Western Gas Partners LP
Form S-1/A
January 23, 2008

Table of Contents

As filed with the Securities and Exchange Commission on January 23, 2008
Registration No. 333-146700

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

Amendment No. 2
to
Form S-1

REGISTRATION STATEMENT UNDER THE SECURITIES ACT OF 1933

WESTERN GAS PARTNERS, LP
(Exact Name of Registrant as Specified in Its Charter)

Delaware	**1311**	**26-1075808**
(State or Other Jurisdiction of Incorporation or Organization)	*(Primary Standard Industrial Classification Code Number)*	*(I.R.S. Employer Identification Number)*

1201 Lake Robbins Drive
The Woodlands, Texas 77380-1046
(832) 636-1000
(Address, Including Zip Code, and Telephone Number, Including Area Code, of Registrant s Principal Executive Offices)

Robert G. Gwin
1201 Lake Robbins Drive
The Woodlands, Texas 77380-1046
(832) 636-1000
(Name, Address, Including Zip Code, and Telephone Number, Including Area Code, of Agent for Service)

Copies to:

David P. Oelman	**G. Michael O Leary**
Vinson & Elkins L.L.P.	**Andrews Kurth LLP**
1001 Fannin Street, Suite 2500	**600 Travis Street, Suite 4200**
Houston, Texas 77002	**Houston, Texas 77002**

(713) 758-2222	**(713) 220-4200**

Approximate date of commencement of proposed sale to the public: As soon as practicable after this Registration Statement becomes effective.

If any of the securities being registered on this form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933, check the following box. o

If this form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If this form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If this form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If delivery of the prospectus is expected to be made pursuant to Rule 434, please check the following box. o

The Registrant hereby amends this Registration Statement on such date or dates as may be necessary to delay its effective date until the Registrant shall file a further amendment which specifically states that this Registration Statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933 or until the Registration Statement shall become effective on such date as the Securities and Exchange Commission, acting pursuant to said Section 8(a), may determine.

Table of Contents

The information in this preliminary prospectus is not complete and may be changed. We may not sell these securities until the registration statement filed with the Securities and Exchange Commission is effective. This preliminary prospectus is not an offer to sell these securities and we are not soliciting offers to buy these securities in any jurisdiction where the offer or sale is not permitted.

PRELIMINARY PROSPECTUS Subject to Completion January 23, 2008

18,750,000 Common Units

Representing Limited Partner Interests

This is the initial public offering of our common units. We currently estimate that the initial public offering price will be between $20.00 and $22.00 per common unit. Prior to this offering, there has been no public market for the common units. Our common units have been approved for listing on the New York Stock Exchange, subject to official notice of issuance, under the symbol WES.

Investing in our common units involves risks. Please read Risk factors beginning on page 18.

These risks include the following:

Ø We are dependent on a single natural gas producer, Anadarko Petroleum Corporation, for almost all of the natural gas that we gather and transport. A material reduction in Anadarko s production gathered or transported by our assets would result in a material decline in our revenues and cash available for distribution.

Ø We may not have sufficient cash from operations following the establishment of cash 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 and subordinated units.

Ø Because of the natural decline in production from existing wells, our success depends on our ability to obtain new sources of natural gas, which is dependent on certain factors beyond our control. Any decrease in the volumes of natural gas that we gather and transport could adversely affect our business and operating results.

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

Ø Cost reimbursements due to Anadarko 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 you. The amount and timing of such reimbursements will be determined by our general partner.

Ø You will have limited voting rights and are not entitled to elect our general partner or its directors.

Ø Even if you are dissatisfied, you cannot initially remove our general partner without its consent.

Ø Our general partner interest or the control of our general partner may be transferred to a third party without your consent.

- Ø You will experience immediate and substantial dilution in pro forma net tangible book value of $6.09 per common unit.
- Ø You will be required to pay taxes on your share of our income even if you do not receive any cash distributions from us.

	Per common unit	Total
Public offering price	$	$
Underwriting discounts and commissions(1)	$	$
Proceeds, before expenses, to Western Gas Partners, LP	$	$

(1) Excludes a structuring fee payable to UBS Securities LLC that is equal to % of the gross proceeds of this offering, or approximately $.

We have granted the underwriters a 30-day option to purchase up to an additional 2,812,500 common units from us on the same terms and conditions as set forth above if the underwriters sell more than 18,750,000 common units in this offering.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or passed upon the adequacy or accuracy of this prospectus. Any representation to the contrary is a criminal offense.

The underwriters expect to deliver the common units on or about , 2008.

Joint Book-Running Managers

UBS Investment Bank **Citi** **Credit Suisse** **Morgan Stanley**

Banc of America Securities LLC
Goldman, Sachs & Co.
JPMorgan
Lehman Brothers
Wachovia Securities

Scotia Capital
Bear, Stearns & Co. Inc.
Friedman Billings Ramsey
Stifel Nicolaus

Table of Contents

Table of Contents

You should rely only on the information contained in this prospectus and any free writing prospectus prepared by us or on our behalf. We have not, and the underwriters have not, authorized anyone to provide you with different information. If anyone provides you with different or inconsistent information, you should not rely on it. We are not, and the underwriters are not, making an offer to sell these securities in any jurisdiction where an offer or sale is not permitted. You should assume that the information appearing in this prospectus is accurate as of the date on the front cover of this prospectus. Our business, financial condition, results of operations and prospects may have changed since that date.

TABLE OF CONTENTS

Table of Contents

Table of Contents

Through and including , 2008 (the 25th day after the date of this prospectus), federal securities law may require all dealers that effect transactions in these securities, whether or not participating in this offering, to deliver a prospectus. This requirement is in addition to the dealers obligation to deliver a prospectus when acting as underwriters and with respect to their unsold allotments or subscriptions.

Prospectus summary

This summary provides a brief overview of information contained elsewhere in this prospectus. Because it is abbreviated, this summary does not contain all of the information that you should consider before investing in our common units. You should read the entire prospectus carefully, including the historical and pro forma combined financial statements and the notes to those financial statements. The information presented in this prospectus assumes (1) an initial public offering price of $21.00 per common unit and (2) unless otherwise indicated, that the underwriters option to purchase additional common units is not exercised. You should read Risk factors beginning on page 18 for more information about important risks that you should consider carefully before investing in our common units. We include a glossary of some of the terms used in this prospectus as Appendix B.

Unless the context otherwise requires, references in this prospectus to (i) Western Gas Partners, LP, we, our, us or like terms, when used in a historical context, refer to our Predecessor, as defined in Summary historical and pro forma financial data, and when used in the present tense or prospectively, refer to Western Gas Partners, LP and its subsidiaries; (ii) Anadarko refers to Anadarko Petroleum Corporation and its subsidiaries and affiliates, other than Western Gas Partners, LP and Western Gas Holdings, LLC, our general partner, as of the closing date of this offering; (iii) Anadarko Petroleum Corporation refers to Anadarko Petroleum Corporation excluding its subsidiaries and affiliates; and (iv) MIGC refers to MIGC, Inc.

OVERVIEW

We are a growth-oriented Delaware limited partnership recently formed by Anadarko (NYSE: APC) to own, operate, acquire and develop midstream energy assets. We currently operate in East Texas, the Rocky Mountains, the Mid-Continent and West Texas and are engaged in the business of gathering, compressing, treating and transporting natural gas for our ultimate parent, Anadarko, and third-party producers and customers. We principally provide our midstream services under long-term contracts with fee-based rates extending for primary terms of up to 20 years. We generally do not take title to the natural gas that we gather and, therefore, are able to avoid significant direct commodity price exposure.

We believe that one of our principal strengths is our relationship with Anadarko. During each of the year ended December 31, 2006 and the nine months ended September 30, 2007, over 90% of our total natural gas gathering and transportation volumes were comprised of natural gas production owned or controlled by Anadarko. Anadarko Petroleum Corporation has dedicated to us all of the natural gas production it owns or controls from (i) wells that are currently connected to our gathering systems, and (ii) additional wells that are drilled within one mile of connected wells or our gathering systems, as the systems currently exist and as they are expanded to connect additional wells in the future. As a result, this dedication will continue to expand as additional wells are connected to our gathering systems. Volumes associated with this dedication averaged approximately 736 MMBtu/d for the year ended December 31, 2006 and 738 MMBtu/d for the nine months ended September 30, 2007.

We expect to utilize the significant experience of Anadarko s management team to execute our growth strategy, which includes acquiring and constructing additional midstream assets. For the nine months ended September 30, 2007, as adjusted for divestitures prior to this offering and including the assets being contributed to us, Anadarko s total domestic midstream asset portfolio consisted of 25 gathering systems and one transportation system with an aggregate throughput of approximately 3.0 Bcf/d, approximately 11,200 miles of pipeline and 25 processing and/or treating facilities.

Table of Contents

OUR ASSETS AND AREAS OF OPERATION

Our assets consist of six gathering systems, five natural gas treating facilities and one interstate pipeline. Our assets are located in East Texas, the Rocky Mountains (Utah and Wyoming), the Mid-Continent (Kansas and Oklahoma) and West Texas. The following table provides information regarding our assets by operating area as of or for the nine months ended September 30, 2007:

Area	Asset Type	Length (miles)	Approximate # of receipt points	Gas compression (horsepower)	Treating capacity (MMcf/d)	Average throughput (MMcf/d)
East Texas	Gathering and Treating	577	789	45,633	510	304[(1)]
Rocky Mountains	Gathering and Treating	114	162	20,385	92	55
	Transportation	264	19	29,696		137
Mid-Continent	Gathering	1,753	1,507	130,720		123
West Texas	Gathering	87	50			185
Total		2,795	2,527	226,434	602	804

(1) To avoid duplicating volumes, 213 MMcf/d that is gathered on our Dew gathering system and delivered into our Pinnacle gas treating system is included only once in the calculation of average throughput.

STRATEGY

Our primary business objective is to increase our cash distribution per unit over time. We intend to accomplish this objective by executing the following strategy:

Ø *Pursuing accretive acquisitions.* We expect to pursue accretive acquisition opportunities within the midstream energy industry from Anadarko and third parties.

Ø *Capitalizing on organic growth opportunities.* We expect to grow organically by meeting Anadarko s gathering needs, which we expect to increase as a result of its anticipated drilling activity in our areas of operation.

Ø *Attracting additional third-party volumes to our systems.* We intend to actively market our midstream services to and pursue strategic relationships with third-party producers to attract additional volumes and/or expansion opportunities.

Ø *Minimizing commodity price exposure.* Our midstream services are provided under fee-based arrangements which minimize our direct commodity price exposure. We expect to utilize hedging to manage any significant future commodity price risk that could result from contracts we may acquire or enter into in the future.

COMPETITIVE STRENGTHS

We believe that we are well positioned to successfully execute our strategy and achieve our primary business objective because of the following competitive strengths:

- *Affiliation with Anadarko.* We believe Anadarko, as the owner of our general partner interest, all of our incentive distribution rights and a 57.3% limited partner interest in us, is motivated to promote and support the successful execution of our business plan and to pursue projects that enhance the value of our business.

- *Relatively stable and predictable cash flow.* Our cash flow is largely protected from fluctuations caused by commodity price volatility due to the fee-based, long-term nature of our midstream service agreements.

- *Well-positioned, well-maintained and efficient assets*. We believe that our established positions in our areas of operation provide us with opportunities to expand and attract additional volumes to our systems. Moreover, our systems consist of high-quality, well-maintained assets for which we have implemented modern treating, measuring and operating technologies.

Table of Contents

Ø *Financial flexibility to pursue expansion and acquisition opportunities*. We have up to $100 million of borrowing capacity available to us under Anadarko s $750 million credit facility and, concurrently with the closing of this offering, we expect to obtain a $30 million working capital facility from Anadarko. In addition, we will have no indebtedness outstanding at the closing of this offering. We believe that our borrowing capacity and our ability to effectively access debt and equity capital markets provide us with the financial flexibility necessary to achieve our organic expansion and acquisition strategy.

Ø *Experienced management team.* Members of our general partner s management team have extensive experience in building, acquiring, integrating, financing and managing midstream assets. In addition, our relationship with Anadarko provides us with the services of experienced personnel who successfully managed our assets and operations while they were owned by Anadarko.

We believe that we will effectively leverage our competitive strengths to successfully implement our strategy; however, our business involves numerous risks and uncertainties which may prevent us from achieving our primary business objective. For a more complete description of the risks associated with an investment in us, please read Risk factors.

OUR RELATIONSHIP WITH ANADARKO PETROLEUM CORPORATION

One of our principal attributes is our relationship with Anadarko. It will own our general partner and a significant interest in us following this offering. Anadarko is one of the largest independent oil and gas exploration and production companies in the world. Anadarko s upstream oil and gas business finds and produces natural gas, crude oil, condensate and natural gas liquids, or NGLs, and Anadarko annually pursues one of the most active drilling programs in the industry. At September 30, 2007, including the assets being contributed to us but adjusted for divestitures prior to this offering, Anadarko s total domestic midstream asset portfolio consisted of 25 gathering systems and one transportation system with an aggregate throughput of approximately 3.0 Bcf/d, approximately 11,200 miles of pipeline and 25 processing and/or treating facilities.

Following this offering, Anadarko s remaining midstream business will consist of 19 gathering systems with an aggregate throughput of approximately 2.2 Bcf/d, 8,400 miles of pipeline and 20 processing and/or treating facilities. Anadarko has invested significant capital into its domestic midstream business, including the assets being contributed to us, with investments of approximately $290 million in 2006 and planned investments of approximately $600 million in 2007, of which approximately $475 million had been invested as of September 30, 2007. On December 27, 2007, Anadarko announced a $2.2 billion financing of its midstream assets which may require partial repayment based on a debt to EBITDA leverage ratio that declines incrementally over time. The debt repayments that may be necessary to satisfy the terms of this financing may be made with internally generated cash flow, cash on hand, or cash received from midstream asset sales. Should Anadarko choose to pursue midstream asset sales, it is under no contractual obligation to offer assets or business opportunities to us. We are neither a guarantor nor an obligor for such financing.

Upon completion of this offering, Anadarko will own a 2.0% general partner interest in us, all of our incentive distribution rights and a 57.3% limited partner interest in us. We will enter into an omnibus agreement with Anadarko and our general partner that will govern our relationship with them regarding certain reimbursement and indemnification matters. Please read Certain relationships and related party transactions Agreements governing the transactions Omnibus agreement. Although our relationship with Anadarko provides us with a significant advantage in the midstream natural gas market, it is also a source of potential conflicts. For example, Anadarko is not restricted from competing with us. Please read Conflicts of interest and fiduciary duties. Given Anadarko s significant ownership of limited and general partner interests in us following this offering, we believe it will be in Anadarko s best interest for it to sell additional assets to us over time; however, Anadarko continually evaluates acquisitions and divestitures and may elect to acquire, construct or dispose of midstream assets in the future without offering us the opportunity to acquire or construct those assets. Anadarko is under no contractual obligation to offer any such opportunities to us, nor are we obligated to participate in any such opportunities. We cannot state with any certainty which, if any, opportunities to acquire assets from Anadarko may be made available to us or if we will elect to pursue any such opportunities.

RISK FACTORS

An investment in our common units involves risks associated with our business, regulatory and legal matters, our limited partnership structure and the tax characteristics of our common units. Please read Risk factors for a more thorough description of these and other risks.

FORMATION TRANSACTIONS AND PARTNERSHIP STRUCTURE

General

We are a growth-oriented Delaware limited partnership recently formed by Anadarko to own, operate, acquire and develop midstream energy assets. At the closing of this offering, assuming that the underwriters do not exercise their option to purchase additional common units, the following transactions, which we refer to as the formation transactions, will occur:

- Anadarko will contribute certain midstream assets to us;
- we will issue to Western Gas Holdings, LLC, our general partner and a subsidiary of Anadarko, 921,385 general partner units representing a 2.0% general partner interest in us as well as all of our incentive distribution rights;
- we will issue to Anadarko 3,823,925 common units and 22,573,925 subordinated units, representing an aggregate 57.3% limited partner interest in us;[1]
- we will issue 18,750,000 common units to the public, representing a 40.7% limited partner interest in us;[1]
- we will receive gross proceeds of $393.8 million from the issuance and sale of 18,750,000 common units at an assumed initial offering price of $21.00 per unit;
- we will use the proceeds from this offering to pay underwriting discounts and a structuring fee totaling approximately $25.6 million and other estimated offering expenses of $5.0 million;
- we will use the remaining $363.2 million of aggregate net proceeds of this offering to (i) make a loan of $337.6 million to Anadarko in exchange for a 30-year note bearing interest at a fixed annual rate of 6.00%, (ii) reimburse Anadarko for $15.5 million of capital expenditures it incurred with respect to assets contributed to us and (iii) provide $10.0 million for general partnership purposes;
- we will have up to $100 million of long-term borrowing capacity available to us under Anadarko s $750 million credit facility;
- we will enter into a $30 million working capital facility with Anadarko as the lender;
- we will enter into an omnibus agreement with Anadarko and our general partner pursuant to which, among other things, (i) we will reimburse Anadarko and our general partner for certain expenses incurred on our behalf, including expenses for various general and administrative services rendered by Anadarko and our general partner to us, and (ii) the parties will agree to certain indemnification obligations;

- our general partner will enter into a services and secondment agreement with Anadarko, pursuant to which certain employees of Anadarko will be under our control and render services to us or on our behalf; and

- our general partner will enter into a tax sharing agreement with Anadarko, pursuant to which we will pay Anadarko for our share of state and local income and other taxes that are included in combined or consolidated tax returns filed by Anadarko.

(1) If the underwriters exercise their option to purchase up to 2,812,500 additional common units within 30 days of this offering, the number of units purchased by the underwriters pursuant to such exercise will be issued to the public instead of Anadarko.

Table of Contents

Ownership of Western Gas Partners, LP

The diagram below illustrates our organization and ownership after giving effect to the offering and the related formation transactions and assumes that the underwriters option to purchase additional common units is not exercised.

Public Common Units	40.7%
Anadarko Common and Subordinated Units	57.3%
General Partner Units	2.0%
Total	100.0%

Table of Contents

OUR MANAGEMENT

Our general partner has sole responsibility for conducting our business and for managing our operations and will be controlled by our ultimate parent, Anadarko. Pursuant to the omnibus agreement and the services and secondment agreement that we will enter into concurrently with the closing of this offering, Anadarko and our general partner will be entitled to reimbursement for all direct and indirect expenses that they incur on our behalf. Under the omnibus agreement, our reimbursement to Anadarko for certain general and administrative expenses it allocates to us will be capped at $6.0 million annually through December 31, 2009, subject to adjustments to reflect changes in the Consumer Price Index and, with the concurrence of the special committee of our general partner s board of directors, to reflect expansions of our operations through the acquisition or construction of new assets or businesses. Thereafter, our general partner will determine the general and administrative expenses to be reimbursed by us in accordance with our partnership agreement. The cap contained in the omnibus agreement does not apply to incremental general and administrative expenses we expect to incur or to be allocated to us as a result of becoming a publicly traded partnership. We currently expect those expenses to be approximately $2.5 million per year. Please read Certain relationships and related party transactions Agreements governing the transactions Omnibus agreement and Services and secondment agreement.

Neither our general partner nor its board of directors will be elected by our unitholders. Anadarko is the sole member of our general partner and will have the right to appoint our general partner s entire board of directors. Certain of our officers and directors are also officers of Anadarko.

As is common with publicly traded partnerships and in order to maximize operational flexibility, we will conduct our operations through subsidiaries. We will initially have one direct subsidiary, Western Gas Operating, LP, a limited partnership that will conduct business itself and through its subsidiaries.

PRINCIPAL EXECUTIVE OFFICES AND INTERNET ADDRESS

Our principal executive offices are located at 1201 Lake Robbins Drive, The Woodlands, Texas 77380, and our telephone number is (832) 636-1000. We expect our website to be located at www.westerngas.com. We expect to make available our periodic reports and other information filed with or furnished to the Securities and Exchange Commission, which we refer to as the SEC, free of charge through our website, as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC. Information on our website or any other website is not incorporated by reference herein and does not constitute a part of this prospectus.

OUR GENERAL PARTNER S RIGHT TO RECEIVE DISTRIBUTIONS

2.0% general partner interest

Our general partner initially will be entitled to receive 2.0% of our quarterly cash distributions. This 2.0% interest will initially be represented by 921,385 general partner units. General partner units are not deemed outstanding units for purposes of voting rights and such units represent a non-voting general partner interest. Our general partner s initial 2.0% interest in these distributions will be reduced if we issue additional units in the future and our general partner does not elect to contribute a proportionate amount of capital to us to maintain its initial 2.0% general partner interest. If and to the extent our general partner elects to contribute sufficient capital to maintain its 2.0% general partner interest, it will be issued the number of general partner units necessary to maintain its 2.0% interest. All references in this prospectus to our general partner s 2.0% general partner interest assume that our general partner will elect to make these additional capital contributions in order to maintain its right to receive 2.0% of our cash distributions.

Incentive distributions

In addition to its 2.0% general partner interest, our general partner holds the incentive distribution rights, which are non-voting limited partner interests that represent the right to receive an increasing

6

Table of Contents

percentage of quarterly distributions of available cash as higher target distribution levels of cash are achieved. The following table shows how our available cash will be distributed among our unitholders and our general partner as higher target distribution levels are met:

	Total quarterly distribution per unit	Marginal percentage interest in distributions[1]	
		Unitholders	General partner
Minimum Quarterly Distribution	$0.300	98.0%	2.0%
First Target Distribution	up to $0.345	98.0%	2.0%
Second Target Distribution	above $0.345 up to $0.375	85.0%	15.0%
Third Target Distribution	above $0.375 up to $0.450	75.0%	25.0%
Thereafter	above $0.450	50.0%	50.0%

(1) *Assumes that there are no arrearages on common units and that our general partner maintains its 2.0% general partner interest and continues to own the incentive distribution rights.*

For a more detailed description of the incentive distribution rights, please read Provisions of our partnership agreement relating to cash distributions General partner interest and incentive distribution rights.

Our general partner s right to reset the target distribution levels

Our general partner has the right, at any time when there are no subordinated units outstanding and it has received incentive distributions at the highest level to which it is entitled (48%) for each of the prior four consecutive fiscal quarters, to reset the initial target distribution levels to higher levels based on our cash 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 reset to an amount equal to the average cash distribution per common unit for the two fiscal quarters immediately preceding the reset election (we refer to such amount as the reset minimum quarterly distribution), and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution. As a result, following a reset, we would distribute all of our available cash for each quarter thereafter as follows (assuming our general partner maintains its 2.0% general partner interest and the ownership of the incentive distribution rights):

- *first*, 98.0% to all unitholders, pro rata, and 2.0% to our general partner, until each unitholder receives a total amount equal to 115% of the reset minimum quarterly distribution for that quarter;
- *second*, 85.0% to all unitholders, pro rata, and 15.0% to our general partner, until each unitholder receives a total amount per unit equal to 125% of the reset minimum quarterly distribution for the quarter;
- *third*, 75.0% to all unitholders, pro rata, and 25.0% to our general partner, until each unitholder receives a total amount per unit equal to 150% of the reset minimum quarterly distribution for the quarter; and
- *thereafter*, 50.0% to all unitholders, pro rata, and 50.0% to our general partner.

If our general partner elects to reset the target distribution levels, it will be entitled to receive a number of Class B units and general partner units. The Class B units will be entitled to the same cash distributions per unit as our common units and will be convertible into an equal number of common units. The number of Class B units to be issued to our general partner will be equal to that number of common units which would have entitled their holder to an average aggregate quarterly cash distribution in the prior two quarters equal to the average of the distributions to our general partner on the incentive distribution rights in the prior two quarters. Our general partner will be issued the number of general partner units necessary to maintain our general partner s interest in us immediately prior to the reset election.

SUMMARY OF CONFLICTS OF INTEREST AND FIDUCIARY DUTIES

General

Our general partner has a legal duty to manage us in a manner beneficial to holders of our common and subordinated units. This legal duty originates in statutes and judicial decisions and is commonly referred to as a fiduciary duty. However, the officers and directors of our general partner also have fiduciary duties to manage our general partner in a manner beneficial to its owner, Anadarko. Certain of the officers and directors of our general partner are also officers of Anadarko. As a result, conflicts of interest will arise in the future between us and holders of our common and subordinated units, on the one hand, and Anadarko and our general partner, on the other hand. For example, our general partner will be entitled to make determinations that affect the amount of cash distributions we make to the holders of common units, which in turn has an effect on whether our general partner receives incentive cash distributions as discussed above.

Partnership agreement modifications to fiduciary duties

Our partnership agreement limits the liability of, and reduces the fiduciary duties owed by, our general partner to holders of our common and subordinated units. Our partnership agreement also restricts the remedies available to holders of our common and subordinated units for actions that might otherwise constitute a breach of our general partner s fiduciary duties. By purchasing a common unit, the purchaser agrees to be bound by the terms of our partnership agreement, and pursuant to the terms of our partnership agreement, each holder of common units consents to various actions and potential conflicts of interest contemplated in the partnership agreement that might otherwise be considered a breach of fiduciary or other duties under applicable state law.

Anadarko may engage in competition with us

Neither our partnership agreement nor the omnibus agreement between us and Anadarko will prohibit Anadarko from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, Anadarko may acquire, construct or dispose of additional midstream or other assets in the future, without any obligation to offer us the opportunity to acquire or construct any of those assets.

For a more detailed description of the conflicts of interest and the fiduciary duties of our general partner, please read Conflicts of interest and fiduciary duties.

Table of Contents

The offering

Common units offered to the public	18,750,000 common units 21,562,500 common units, if the underwriters exercise in full their option to purchase additional common units
Units outstanding after this offering	22,573,925 common units(1) and 22,573,925 subordinated units, each representing a 49.0% limited partner interest in us. Our general partner will own 921,835 general partner units, representing a 2.0% general partner interest in us.
Use of proceeds	We expect to receive gross proceeds of \$393.8 million from this offering. We will use the proceeds to (i) make a loan of \$337.6 million to Anadarko in exchange for a 30-year note bearing interest at a fixed annual rate of 6.00%, (ii) reimburse Anadarko for \$15.5 million of capital expenditures it incurred with respect to assets contributed to us, (iii) provide \$10.0 million for general partnership purposes and (iv) pay underwriting discounts and a structuring fee totaling approximately \$25.6 million and other estimated offering expenses of \$5.0 million. The net proceeds from any exercise of the underwriters option to purchase additional common units will be used to reimburse Anadarko for capital expenditures it incurred with respect to the assets contributed to us.
Cash distributions	Our general partner will adopt a cash distribution policy that will require us to pay a minimum quarterly distribution of \$0.30 per unit (\$1.20 per unit on an annualized basis) to the extent we have sufficient cash from operations after establishment of cash reserves and payment of fees and expenses, including payments to our general partner and its affiliates. We refer to this cash as available cash, and it is defined in our partnership agreement included in this prospectus as Appendix A and in the glossary included in this prospectus as Appendix B. Our ability to pay the minimum quarterly distribution is subject to various restrictions and other factors described in more detail under the caption Our cash distribution policy and restrictions on distributions. We will adjust the minimum quarterly distribution payable for the period from the completion of this offering through March 31, 2008, based on the actual length of that period. Our partnership agreement requires that we distribute all of our available cash each quarter in the following manner: Ø *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 \$0.30 plus any arrearages from prior quarters;

Ø *second*, 98.0% to the holders of subordinated units and 2.0% to our general partner, until each subordinated unit

(1) Excludes common units subject to issuance under our Long-Term Incentive Plan. Please read Management Long-term incentive plan.

9

Table of Contents

	has received the minimum quarterly distribution of $0.30; and
	Ø *third*, 98.0% to all unitholders, pro rata, and 2.0% to our general partner, until each unit has received a distribution of $0.345.
	If cash distributions to our unitholders exceed $0.345 per unit in any quarter, our general partner will receive, in addition to distributions on its 2.0% general partner interest, increasing percentages, up to 48.0%, of the cash we distribute in excess of that amount. We refer to these distributions as incentive distributions. Please read Provisions of our partnership agreement relating to cash distributions.
	The amounts of pro forma available cash generated during each of the year ended December 31, 2006 and twelve months ended September 30, 2007 would have been sufficient to allow us to pay the full minimum quarterly distribution ($0.30 per unit per quarter, or $1.20 on an annualized basis) on all of our common and subordinated units for such periods. Please read Our cash distribution policy and restrictions on distributions.
	We believe that, based on the Statement of Estimated Adjusted EBITDA included under the caption Our cash distribution policy and restrictions on distributions, we will have sufficient cash available for distribution to pay the minimum quarterly distribution of $0.30 per unit on all common and subordinated units and the corresponding distributions on our general partner s 2.0% interest for the four quarters ending December 31, 2008.
Subordinated units	Anadarko will initially indirectly own all of our subordinated units. The principal difference between our common and subordinated units is that in any quarter during the subordination period, holders of the 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. Subordinated units will not accrue arrearages.
Conversion of subordinated units	The subordination period will end on the first business day after we have earned and paid at least (i) $1.20 (the minimum quarterly distribution on an annualized basis) on each outstanding common and subordinated unit and the corresponding distribution on our general partner s 2.0% interest for each of three consecutive, non-overlapping four quarter periods ending on or after March 31, 2011 or (ii) $0.45 per quarter (150% of the minimum quarterly distribution, which is $1.80 on an annualized basis) on each outstanding common and subordinated unit and the corresponding distributions on our general partner s 2.0% interest for each of four consecutive quarters.

Table of Contents

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 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.

General partner s right to reset the target distribution levels

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

If our general partner elects to reset the target distribution levels, it will be entitled to receive Class B units and additional general partner units. The Class B units will be entitled to the same cash distributions per unit as our common units and will be convertible into an equal number of common units. The number of Class B units to be issued to our general partner will be equal to that number of common units which would have entitled their holder to an average aggregate quarterly cash distribution in the prior two quarters equal to the average of the distributions to our general partner on the incentive distribution rights in the prior two quarters. Our general partner will be issued the number of general partner units necessary to maintain our general partner s interest in us immediately prior to the reset election. Please read Provisions of our partnership agreement relating to cash distributions General partner s right to reset incentive distribution levels.

Issuance of additional units

We can issue an unlimited number of units without the consent of our unitholders. Please read Units eligible for future sale and The partnership agreement Issuance of additional securities.

Limited voting rights

Our general partner will manage and operate us. Unlike the holders of common stock in a corporation, you will have only limited voting rights on matters affecting our business. You will have no right to elect our general partner or its directors on an annual or continuing basis. Our general partner may not be removed except by a vote of the holders of at least 662/3% of the outstanding limited partner units voting together as a single class, including any limited partner units owned by our general partner and its affiliates, including Anadarko. Upon consummation of this offering, Anadarko will own an

11

	aggregate of 58.5% of our common and subordinated units. This will give Anadarko the ability to prevent the involuntary removal of our general partner. Please read The partnership agreement Voting rights.
Limited call right	If at any time our general partner and its affiliates own more than 80% of the outstanding common units, our general partner has the right, but not the obligation, to purchase all of the remaining common units at a price that is not less than the then-current market price of the common units.
Estimated ratio of taxable income to distributions	We estimate that if you own the common units you purchase in this offering through the record date for distributions for the period ending December 31, 2010, you will be allocated, on a cumulative basis, an amount of federal taxable income for that period that will be 35% or less of the cash distributed to you with respect to that period. For example, if you receive an annual distribution of $1.20 per unit, we estimate that your average allocable federal taxable income per year will be no more than $0.42 per unit. Please read Material tax consequences Tax consequences of unit ownership Ratio of taxable income to distributions and Material tax consequences Tax consequences of unit ownership Limitations on deductibility of losses.
Material tax consequences	For a discussion of other material federal income tax consequences that may be relevant to prospective unitholders who are individual citizens or residents of the United States, or the U.S., please read Material tax consequences.
Exchange listing	Our common units have been approved for listing on the New York Stock Exchange, subject to notice of issuance, under the symbol WES.

Summary historical and pro forma financial and operating data

The following table shows (i) the summary combined historical financial and operating data of our Predecessor, which is comprised of Anadarko Gathering Company and Pinnacle Gas Treating, Inc., with MIGC reported as an acquired business of our Predecessor, and (ii) the summary combined pro forma as adjusted financial and operating data of Western Gas Partners, LP (the Partnership), for the periods and as of the dates indicated. The information in the following table should be read together with Management s discussion and analysis of financial condition and results of operations.

Our Predecessor s summary combined historical balance sheet data as of December 31, 2006 and 2005 and summary combined historical statement of income and cash flow data for the years ended December 31, 2006, 2005 and 2004 are derived from the audited historical combined financial statements of our Predecessor included elsewhere in this prospectus. Our Predecessor s summary combined historical balance sheet data as of December 31, 2004 are derived from the unaudited historical combined financial statements of our Predecessor not included in this prospectus. Our Predecessor s summary combined historical balance sheet data as of September 30, 2007 and summary combined historical statement of income and cash flow data for the nine months ended September 30, 2007 and 2006 are derived from the unaudited historical combined financial statements of our Predecessor included elsewhere in this prospectus. Our Predecessor s summary combined historical balance sheet data as of September 30, 2006 are derived from the unaudited historical combined financial statements of our Predecessor not included in this prospectus.

The Partnership s summary combined pro forma as adjusted statement of income data for the year ended December 31, 2006 and the nine months ended September 30, 2007 and summary combined pro forma as adjusted balance sheet data as of September 30, 2007 are derived from the unaudited pro forma combined financial statements of the Partnership included elsewhere in this prospectus.

The pro forma adjustments have been prepared as if the acquisition of MIGC by our Predecessor occurred on January 1, 2006 and as if certain transactions to be effected at the closing of this offering had taken place on September 30, 2007, in the case of the pro forma balance sheet, and on January 1, 2006, in the case of the pro forma statements of operations for the year ended December 31, 2006 and the nine months ended September 30, 2007. These transactions include:

- the receipt by the Partnership of gross proceeds of $393.8 million from the issuance and sale of 18,750,000 common units at an assumed initial offering price of $21.00 per unit;
- the use of the proceeds from this offering to pay underwriting discounts and a structuring fee totaling approximately $25.6 million and other estimated offering expenses of $5.0 million; and
- the use of the remaining $363.2 million of aggregate net proceeds of this offering to (i) make a loan of $337.6 million to Anadarko in exchange for a 30-year note bearing interest at a fixed annual rate of 6.00%, (ii) reimburse Anadarko for $15.5 million of capital expenditures it incurred with respect to assets contributed to us and (iii) provide $10.0 million for general partnership purposes.

The following table includes our Predecessor s historical and our pro forma Adjusted EBITDA, which have not been prepared in accordance with generally accepted accounting principles (GAAP). Adjusted EBITDA is presented because it is helpful to management, industry analysts, investors, lenders and rating agencies and may be used to assess the financial performance and operating results of our fundamental business activities. For a reconciliation of Adjusted EBITDA to its most directly comparable financial measures calculated and presented in accordance with GAAP, please read Non-GAAP financial measure below.

Table of Contents

	Predecessor combined					Partnership pro forma as adjusted	
	Year ended December 31,			Nine months ended September 30,		Nine months ended September 30,	Year ended December 31,
	2006	2005	2004	2007	2006	2007	2006
	(in thousands, except for operating and per unit data)						
Statement of Income Data:							
Total revenues	$ 81,152	$ 71,650	$ 68,049	$ 85,513	$ 57,481	$ 85,513	$ 93,304
Costs and expenses	39,960	35,720	31,301	33,184	29,057	33,184	43,857
Depreciation	18,009	15,447	14,841	17,104	12,635	17,104	19,710
Total operating expenses	57,969	51,167	46,142	50,288	41,692	50,288	63,567
Operating income	23,183	20,483	21,907	35,225	15,789	35,225	29,737
Other expense (income)	26	(66)			25		377
Interest expense (income)	9,631	8,650	7,146	6,643	7,943	(15,022)	(20,030)
Income tax expense	3,814	4,789	5,504	10,469	1,740	160	978
Net income	$ 9,712	$ 7,110	$ 9,257	$ 18,113	$ 6,081	$ 50,087	$ 48,412
General partner interest in pro forma net income						1,315	968
Common unitholders interest in pro forma net income						24,386	27,089
Subordinated unitholder s interest in pro forma net income						24,386	20,355
Net income per common unit (basic and diluted)						$ 1.08	$ 1.20
Net income per subordinated unit (basic and diluted)						$ 1.08	$ 0.90
Balance Sheet Data (at period end):							
Net, property, plant and equipment	$ 310,871	$ 200,451	$ 196,065	$ 353,294	$ 302,057	$ 353,294	

Total assets	332,228	206,373	199,110	360,692	324,772	708,306	
Total partners capital/parent net equity	238,531	160,585	162,542	273,507	234,063	691,561	
Cash Flow Data:							
Net cash provided by (used in):							
Operating activities	27,323	30,131	31,160	41,810	12,941		
Investing activities	(42,713)	(21,076)	(16,548)	(37,247)	(27,952)		
Financing activities	15,844	(9,067)	(14,596)	(5,021)	15,007		
Adjusted EBITDA(1)	41,192	35,930	36,748	52,329	28,424	52,329	49,447
Capital expenditures, net	42,299	20,841	16,548	37,020	27,709		
Operating Data:							
Affiliate							
Throughput, MMBtu/d	820	757	715	904	778	904	878
Average rate per MMBtu	$ 0.22	$ 0.21	$ 0.21	$ 0.28	$ 0.22	$ 0.28	$ 0.23
Third Party							
Throughput, MMBtu/d	72	41	31	90	64	90	93
Average rate per MMBtu	$ 0.19	$ 0.16	$ 0.13	$ 0.25	$ 0.21	$ 0.25	$ 0.23
Total							
Throughput, MMBtu/d	892	798	746	994	842	994	971
Average rate per MMBtu	$ 0.21	$ 0.21	$ 0.21	$ 0.28	$ 0.22	$ 0.28	$ 0.23

(1) Adjusted EBITDA is defined in Non-GAAP financial measure below.

Table of Contents

NON-GAAP FINANCIAL MEASURE

We define Adjusted EBITDA as net income (loss), plus interest expense, income taxes and depreciation, less interest income and other income (expense). We believe that the presentation of Adjusted EBITDA provides information useful to investors in assessing our financial condition and results of operations and that Adjusted EBITDA is a widely accepted financial indicator of a company s ability to incur and service debt, fund capital expenditures and make distributions. Adjusted EBITDA is a supplemental financial measure that management and external users of our combined financial statements, such as industry analysts, investors, lenders and rating agencies, may use to assess:

Ø our operating performance as compared to other publicly traded partnerships in the midstream energy industry, without regard to financing methods, capital structure or historical cost basis;

Ø the ability of our assets to generate sufficient cash flow to make distributions to our unitholders; and

Ø the viability of acquisitions and capital expenditure projects and the returns on investment of various investment opportunities.

The GAAP measures most directly comparable to Adjusted EBITDA are net income and net cash provided by operating activities. Our non-GAAP financial measure of Adjusted EBITDA should not be considered as an alternative to GAAP net income or net cash provided by operating activities. Adjusted EBITDA has important limitations as an analytical tool because it excludes some but not all items that affect net income and net cash provided by operating activities. You should not consider Adjusted EBITDA in isolation or as a substitute for analysis of our results as reported under GAAP. Because Adjusted EBITDA may be defined differently by other companies in our industry, our definition of Adjusted EBITDA may not be comparable to similarly titled measures of other companies, thereby diminishing its utility.

Management compensates for the limitations of Adjusted EBITDA as an analytical tool by reviewing the comparable GAAP measures, understanding the differences between Adjusted EBITDA and net income and net cash provided by operating activities, and incorporating this knowledge into its decision-making processes. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating our operating results.

Table of Contents

The following table presents a reconciliation of the non-GAAP financial measure of Adjusted EBITDA to the GAAP financial measures of net income and net cash provided by operating activities on an historical and pro forma as adjusted basis:

	Predecessor combined					Partnership pro forma as adjusted	
	Year ended December 31,			Nine months ended September 30,		Nine months ended September 30,	Year ended December 31,
	2006	2005	2004	2007	2006	2007	2006
	(in thousands)						
Reconciliation of Adjusted EBITDA to Net Income							
Net income	$ 9,712	$ 7,110	$ 9,257	$ 18,113	$ 6,081	$ 50,087	$ 48,412
Add:							
Interest expense (income)	9,631	8,650	7,146	6,643	7,943	(15,022)	(20,030)
Income tax expense	3,814	4,789	5,504	10,469	1,740	160	978
Depreciation	18,009	15,447	14,841	17,104	12,635	17,104	19,710
Less:							
Other income (expense)	(26)	66			(25)		(377)
Adjusted EBITDA	$ 41,192	$ 35,930	$ 36,748	$ 52,329	$ 28,424	$ 52,329	$ 49,447
Reconciliation of Adjusted EBITDA to Net Cash Provided by Operating Activities							
Net cash provided by operating activities[1]	$ 27,323	$ 30,131	$ 31,160	$ 41,810	$ 12,941	$ 66,722	$ 64,888
Interest expense (income)	9,631	8,650	7,146	6,643	7,943	(15,022)	(20,030)
Current income tax expense				3,406		159	
Other income (expense)	(26)	66			(25)		(377)
Changes in operating working capital:							
Accounts receivable	(374)	662	(933)	1,062	1,410	1,062	(374)
Accounts payable and accrued expenses	4,556	(3,373)	551	(580)	6,015	(580)	4,556
Other, including changes in non-current assets and liabilities	30	(74)	(1,176)	(12)	90	(12)	30

Adjusted EBITDA	$ 41,192	$ 35,930	$ 36,748	$ 52,329	$ 28,424	$ 52,329	$ 49,447

Table of Contents

(1) Reconciliation of reported amounts of net cash provided by operating activities from reported amounts to pro forma amounts for the nine months ended September 30, 2007 and year ended December 31, 2006:

	Nine months ended September 30, 2007	Year ended December 31, 2006
Net cash provided by operating activities reported	$ 41,810	$ 27,323
Adjustments:		
Additional MIGC net income		4,375
Interest income for MIGC		(574)
Depreciation for MIGC		918
Depreciation for MIGC basis step up		783
Income tax for MIGC		2,647
Income tax for MIGC depreciation on step up		(245)
Reported interest expense	6,643	9,631
Pro forma interest income	15,193	20,258
Pro forma interest expense	(171)	(228)
Reported income tax expense	10,469	3,814
Reported deferred tax adjustment	(7,063)	(3,814)
Pro forma income tax	(160)	(978)
Pro forma deferred tax adjustment	1(a)	978
Net cash provided by operating activities pro forma	$ 66,722	$ 64,888

(a) Pro forma income tax expense	160
Current income tax expense	159
Deferred income tax expense	1

Risk factors

Limited partner units are inherently different from capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in similar businesses. We urge you to carefully consider the following risk factors together with all of the other information included in this prospectus in evaluating an investment in our common units.

If any of the following risks were to occur, our business, financial condition or results of operations could be materially adversely affected. In that case, we might not be able to pay the minimum quarterly distribution on our common units, the trading price of our common units could decline and you could lose all or part of your investment in us.

RISKS RELATED TO OUR BUSINESS

We are dependent on a single natural gas producer, Anadarko, for almost all of the natural gas that we gather and transport. A material reduction in Anadarko s production gathered or transported by our assets would result in a material decline in our revenues and cash available for distribution.

We rely on Anadarko for virtually all of the natural gas that we gather and transport. For the nine months ended September 30, 2007, Anadarko accounted for over 90% of our natural gas gathering and transportation volumes. We may be unable to negotiate on favorable terms, if at all, extensions or replacements of our contracts to gather, compress, treat and transport Anadarko s production. Furthermore, Anadarko may suffer a decrease in production volumes in the areas serviced by us and is under no contractual obligation to maintain its production dedicated to us. The loss of a significant portion of the natural gas volumes supplied by Anadarko would result in a material decline in our revenues and our cash available for distribution. In addition, Anadarko may determine in the future that drilling activity in other areas of operation is strategically more attractive. A shift in Anadarko s focus away from our areas of operation could result in reduced throughput on our system and a material decline in our revenues.

We may not have sufficient cash from operations following the establishment of cash 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 and subordinated units.

In order to pay the minimum quarterly distribution of $0.30 per unit per quarter, or $1.20 per unit per year, we will require available cash of approximately $13.8 million per quarter, or $55.3 million per year, based on the number of common and subordinated units to be outstanding immediately after completion of this offering. We may not have sufficient available cash from operating surplus 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:

Ø the prices of, level of production of and demand for natural gas;

Ø the volume of natural gas we gather, compress, treat and transport;

Ø the volumes and prices of condensate that we retain and sell;

Ø demand charges and volumetric fees associated with our transportation services;

Ø the level of competition from other midstream energy companies;

- the level of our operating and maintenance and general and administrative costs;

Risk factors

- regulatory action affecting the supply of or demand for natural gas, the rates we can charge, how we contract for services, our existing contracts, our operating costs or our operating flexibility; 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, please read Our cash distribution policy and restrictions on distributions.

The amount of cash we have available for distribution to holders of our common and 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.

The amount of available cash we need to pay the minimum quarterly distribution on all of our units to be outstanding immediately after this offering and the corresponding distribution on our general partner s 2.0% interest for four quarters is approximately $55.3 million. The amounts of pro forma available cash generated during each of the year ended December 31, 2006 and twelve months ended September 30, 2007 would have been sufficient to allow us to pay the full minimum quarterly distribution on all of our common and subordinated units for such periods. For a calculation of our ability to make distributions to unitholders based on our pro forma results for 2006, please read Our cash distribution policy and restrictions on distributions.

The assumptions underlying the forecast of cash available for distribution that we include in Our cash distribution policy and restrictions on distributions are inherently uncertain and are subject to significant business, economic, financial, regulatory and competitive risks and uncertainties that could cause actual results

to differ materially from those forecasted.

The forecast of cash available for distribution set forth in Our cash distribution policy and restrictions on distributions includes our forecasted results of operations, Adjusted EBITDA and cash available for distribution for the twelve months ending December 31, 2008. The financial forecast has been prepared by management, and we have not received an opinion or report on it from our or any other independent auditor. The assumptions underlying the forecast are inherently uncertain and are subject to significant business, economic, financial, regulatory and competitive risks and uncertainties that could cause actual results to differ materially from those forecasted. If we do not achieve the forecasted results, we may not be able to pay the full minimum quarterly distribution or any amount on our common or subordinated units, in which event the market price of our common units may decline materially.

Risk factors

Because of the natural decline in production from existing wells, our success depends on our ability to obtain new sources of natural gas, which is dependent on certain factors beyond our control. Any decrease in the volumes of natural gas that we gather and transport could adversely affect our business and operating results.

The volumes that support our business are dependent on the level of production from natural gas wells connected to our gathering systems, the production of which will naturally decline over time. As a result, our cash flows associated with these wells will also decline over time. In order to maintain or increase throughput levels on our gathering systems, we must obtain new sources of natural gas. The primary factors affecting our ability to obtain non-dedicated sources of natural gas include (i) the level of successful drilling activity near our systems and (ii) our ability to compete for volumes from successful new wells.

While Anadarko has dedicated production from certain of its properties to us, we have no control over the level of drilling activity in our areas of operation, the amount of reserves associated with wells connected to our gathering systems or the rate at which production from a well declines. In addition, we have no control over Anadarko or other producers or their drilling or production decisions, which are affected by, among other things, the availability and cost of capital, prevailing and projected energy prices, demand for hydrocarbons, levels of reserves, geological considerations, governmental regulations, the availability of drilling rigs and other production and development costs. Fluctuations in energy prices can also greatly affect investments by Anadarko and third parties in the development of new natural gas reserves. Declines in natural gas prices could have a negative impact on exploration, development and production activity, and if sustained, could lead to a material decrease in such activity. Sustained reductions in exploration or production activity in our areas of operation would lead to reduced utilization of our gathering and treating assets.

Because of these factors, even if new natural gas reserves are known to exist in areas served by our assets, producers may choose not to develop those reserves. Moreover, Anadarko may not develop the acreage it has dedicated to us. If competition or reductions in drilling activity result in our inability to maintain the current levels of throughput on our systems, it could reduce our revenue and impair our ability to make cash distributions to our unitholders.

We typically do not obtain independent evaluations of natural gas reserves connected to our gathering and transportation systems; therefore, in the future, volumes of natural gas on our systems could be less than we anticipate.

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

Lower natural gas and oil prices could adversely affect our business.

Lower natural gas and oil prices could impact natural gas and oil exploration and production activity levels and result in a decline in the production of natural gas and condensate, resulting in reduced throughput on our systems. Any such decline may cause our current or potential customers to delay drilling or shut in production. In addition, such a decline would reduce the amount of condensate we retain and sell. As a result, lower natural gas prices could have an adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to you.

20

Risk factors

In general terms, the prices of natural gas, oil, condensate, NGLs and other hydrocarbon products fluctuate in response to changes in supply and demand, market uncertainty and a variety of additional factors that are beyond our control. These factors include:

Ø worldwide economic conditions;

Ø weather conditions and seasonal trends;

Ø the levels of domestic production and consumer demand;

Ø the availability of imported liquified natural gas, or LNG;

Ø the availability of transportation systems with adequate capacity;

Ø the volatility and uncertainty of regional pricing differentials such as in the Mid-Continent;

Ø the price and availability of alternative fuels;

Ø the effect of energy conservation measures;

Ø the nature and extent of governmental regulation and taxation; and

Ø the anticipated future prices of natural gas, LNG and other commodities.

Our industry is highly competitive, and increased competitive pressure could adversely affect our business and operating results.

We compete with similar enterprises in our areas of operation. Our competitors may expand or construct gathering, compression, treating or transportation systems that would create additional competition for the services we provide to our customers. In addition, our customers, including Anadarko, may develop their own gathering, compression, treating or transportation systems in lieu of using ours. Our ability to renew or replace existing contracts with our customers at rates sufficient to maintain current revenues and cash flow could be adversely affected by the activities of our competitors and our customers. All of these competitive pressures could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to you.

Our operating income could be affected by a change in oil prices relative to the price of natural gas.

Under our gathering agreements, we retain and sell condensate, which falls out of the natural gas stream during the gathering process, and compensate shippers with a thermally equivalent volume of natural gas. Condensate sales comprised approximately 9% of our gathering system revenues for the nine months ended September 30, 2007. The price we receive for our condensate is generally tied to the market price of oil. The relationship between natural gas prices and oil prices therefore affects the margin on our condensate sales. When natural gas prices are high relative to oil prices, the profit margin we realize on our condensate sales is low due to the higher value of natural gas. Correspondingly, when natural gas prices are low relative to oil prices, the profit margin is high.

If third-party pipelines or other facilities interconnected to our gathering or transportation systems become partially or fully unavailable, or if the volumes we gather or transport do not meet the natural gas quality requirements of such pipelines or facilities, our revenues and cash available for distribution could be adversely affected.

Our natural gas gathering and transportation systems connect to other pipelines or facilities, the majority of which are owned by third parties. The continuing operation of such third-party pipelines or facilities is not within our control. If any of these pipelines or facilities becomes unable to transport natural gas, or if the volumes we gather or transport do not meet the natural gas quality requirements of such pipelines or facilities, our revenues and cash available for distribution could be adversely affected.

Table of Contents

Risk factors

Our interstate natural gas transportation operations are subject to regulation by FERC, which could have an adverse impact on our ability to establish transportation rates that would allow us to earn a reasonable return on our investment, or even recover the full cost of operating our pipeline, thereby adversely impacting our ability to make distributions to you.

MIGC, our interstate natural gas transportation system, is subject to regulation by the Federal Energy Regulatory Commission, or FERC, under the Natural Gas Act of 1938, or the NGA, and the Energy Policy Act of 2005, or the EPAct 2005.

Under the NGA, FERC has the authority to regulate natural gas companies that provide natural gas pipeline transportation services in interstate commerce. Federal regulation extends to such matters as:

- rates, services and terms and conditions of service;
- the types of services MIGC may offer to its customers;
- the certification and construction of new facilities;
- the acquisition, extension, disposition or abandonment of facilities;
- the maintenance of accounts and records;
- relationships between affiliated companies involved in certain aspects of the natural gas business;
- the initiation and discontinuation of services;
- market manipulation in connection with interstate sales, purchases or transportation of natural gas; and
- participation by interstate pipelines in cash management arrangements.

Natural gas companies are prohibited from charging rates that have been determined to be not just and reasonable by FERC. In addition, FERC prohibits natural gas companies from unduly preferring or unreasonably discriminating against any person with respect to pipeline rates or terms and conditions of service.

The rates and terms and conditions for our interstate pipeline services are set forth in a FERC-approved tariff. Pursuant to FERC s jurisdiction over rates, existing rates may be challenged by complaint and proposed rate increases may be challenged by protest. Any successful complaint or protest against our rates could have an adverse impact on our revenues associated with providing transportation service.

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 EPAct 2005, FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1,000,000 per day for each violation. FERC also has the power to order disgorgement of profits from transactions deemed to violate the NGA and EPAct 2005.

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

Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC. We believe that our natural gas pipelines, other than MIGC, meet the traditional tests FERC has used to determine if a pipeline is a gathering pipeline and is, therefore, not subject to FERC jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of substantial ongoing litigation and, over time, FERC policy concerning where to draw the line between activities it regulates and activities excluded from its regulation has changed. The classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements

Table of Contents

Risk factors

and complaint-based rate regulation. In recent years, FERC has taken a more light-handed approach to regulation of the gathering activities of interstate pipeline transmission companies, which has resulted in a number of such companies transferring gathering facilities to unregulated affiliates. As a result of these activities, natural gas gathering may begin to receive greater regulatory scrutiny at both the state and federal levels.

FERC regulation of MIGC, including the outcome of certain FERC proceedings on the appropriate treatment of tax allowances included in regulated rates and the appropriate return on equity, may reduce our transportation revenues, affect our ability to include certain costs in regulated rates and increase our costs of operations, and thus adversely affect our cash available for distribution.

FERC has pending certain proceedings concerning the appropriate allowance for income taxes that may be included in cost-based rates for FERC regulated pipelines owned by publicly traded partnerships that do not directly pay federal income tax. FERC issued a policy permitting such tax allowances in 2005. FERC s policy and its initial application in a specific case were upheld on appeal by the D.C. Circuit in May of 2007 and the D.C. Circuit s decision is final. In December 2006, FERC issued another order addressing the income tax allowance in rates, in which it reaffirmed prior statements regarding its income tax allowance policy, but raised a new issue regarding the implication of the policy statement for publicly traded partnerships. FERC noted that the tax deferral features of a publicly traded partnership may cause some investors to receive, for some indeterminate duration, cash distributions in excess of their taxable income, creating an opportunity for those investors to earn an additional return, funded by ratepayers. Responding to this concern, FERC adjusted the equity rate of return of the pipeline at issue downward based on the percentage by which the publicly traded partnership s cash flow exceeded taxable income. Rehearing is currently pending before FERC.

FERC also has pending a proceeding on the appropriate composition of proxy groups for purposes of determining natural gas and oil pipeline equity returns to be included in cost-of-service based rates. In a policy statement issued July 19, 2007, FERC proposed to permit inclusion of publicly traded partnerships in the proxy group analysis relating to return on equity determinations in rate proceedings, provided that the analysis be limited to actual publicly traded partnership distributions capped at the level of the pipeline s earnings and that evidence be provided in the form of a multiyear analysis of past earnings demonstrating a publicly traded partnership s ability to provide stable earnings over time. In November 2007, the FERC requested additional comments and announced a technical conference regarding the method to be used for creating growth forecasts for publicly traded partnerships.

The ultimate outcome of these proceedings is not certain and may result in new policies being established at FERC that would limit the amount of income tax allowance permitted to be recovered in regulated rates or disallow the full use of distributions to unitholders by pipeline publicly traded partnerships in any proxy group comparisons used to determine return on equity in future rate proceedings. Any such policy developments may adversely affect the ability of MIGC to achieve a reasonable level of return or impose limits on its ability to include a full income tax allowance in cost of service, and therefore could adversely affect our cash available for distribution.

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

Our natural gas gathering, compression, treating and transportation operations are subject to stringent and complex federal, state and local environmental laws and regulations that govern the discharge of materials into the environment or otherwise relate to environmental protection. Examples of these laws include:

- the federal Clean Air Act and analogous state laws that impose obligations related to air emissions;

Risk factors

- the federal Comprehensive Environmental Response, Compensation and Liability Act, also known as CERCLA or the Superfund law, and analogous state laws that regulate the cleanup of hazardous substances that may be or have been released at properties currently or previously owned or operated by us or at locations to which our wastes are or have been transported for disposal;

- the federal Water Pollution Control Act, also known as the Clean Water Act, and analogous state laws that regulate discharges from our facilities into state and federal waters, including wetlands;

- the federal Resource Conservation and Recovery Act, also known as RCRA, and analogous state laws that impose requirements for the storage, treatment and disposal of solid and hazardous waste from our facilities; and

- the Toxic Substances Control Act, also known as TSCA, and analogous state laws that impose requirements on the use, storage and disposal of various chemicals and chemical substances at our facilities.

These laws and regulations may impose numerous obligations that are applicable to our operations, including the acquisition of permits to conduct regulated activities, the incurrence of capital expenditures to limit or prevent releases of materials from our pipelines and facilities, and the imposition of substantial liabilities for pollution resulting from our operations. Numerous governmental authorities, such as the U.S. Environmental Protection Agency, or the EPA, and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly corrective actions. Failure to comply with these laws, regulations and permits may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations and the issuance of injunctions limiting or preventing some or all of our operations.

There is an inherent risk of incurring significant environmental costs and liabilities in connection with our operations due to historical industry operations and waste disposal practices, our handling of hydrocarbon wastes and potential emissions and discharges related to our operations. Joint and several, strict liability may be incurred, without regard to fault, under certain of these environmental laws and regulations in connection with discharges or releases of hydrocarbon wastes on, under or from our properties and facilities, many of which have been used for midstream activities for a number of years, oftentimes by third parties not under our control. Private parties, including the owners of the properties through which our gathering or transportation systems pass and facilities where our wastes are taken for reclamation or disposal, 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. In addition, changes in environmental laws and regulations occur frequently, and any such changes that result in more stringent and costly waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our operations or financial position. We may not be able to recover all or any of these costs from insurance. Please read Business Environmental matters for more information.

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

One of the ways we intend to grow our business is through the construction of new midstream assets. The construction of additions or modifications to our existing systems and the construction of new midstream assets involve numerous regulatory, environmental, political and legal uncertainties that are beyond our control. Such expansion projects may also require the expenditure of significant amounts of capital, and financing may not be available on economically acceptable terms or at all. If we undertake these projects, they may not be completed on schedule, at the budgeted cost, or at all. Moreover, our revenues may not increase immediately upon the expenditure of funds on a particular project. For

24

Risk factors

instance, if we expand a pipeline, the construction may occur over an extended period of time, yet we will not receive any material increases in revenues until the project is completed. Moreover, we could construct facilities to capture anticipated future growth in production in a region in which such growth does not materialize. Since we are not engaged in the exploration for and development of natural gas and oil reserves, we often do not have access to third-party estimates of potential reserves in an area prior to constructing facilities in that area. To the extent we rely on estimates of future production in our decision to construct additions to our systems, such estimates may prove to be inaccurate as a result of the numerous uncertainties inherent in estimating quantities of future production. As a result, new facilities may not be able to attract enough throughput to achieve our expected investment return, which could adversely affect our results of operations and financial condition. In addition, the construction of additions to our existing gathering and transportation assets may require us to obtain new rights-of-way. We may be unable to obtain such rights-of-way and may, therefore, be unable to connect new natural gas volumes to our systems or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for us to obtain new rights-of-way or to renew existing rights-of-way. If the cost of renewing or obtaining new rights-of-way increases, our cash flows could be adversely affected.

If Anadarko were to limit divestitures of midstream assets to us or if we were to be unable to make acquisitions on economically acceptable terms from Anadarko or third parties, our future growth would be limited, and the acquisitions we do make may reduce, rather than increase, our cash generated from operations on a per unit basis.

Our ability to grow depends, in part, on our ability to make acquisitions that increase our cash generated from operations on a per unit basis. The acquisition component of our strategy is based, in large part, on our expectation of ongoing divestitures of midstream energy assets by industry participants, including, most notably, Anadarko. A material decrease in such divestitures would limit our opportunities for future acquisitions and could adversely affect our ability to grow our operations and increase our distributions to our unitholders.

On December 27, 2007, Anadarko announced a $2.2 billion financing of its midstream assets, the proceeds of which were used to further reduce Anadarko s acquisition indebtedness. To facilitate the transaction, Anadarko formed a subsidiary, WGR Asset Holding Company LLC, or WGRAH, that owns or has rights to substantially all of Anadarko s midstream assets (including the assets to be contributed to us in connection with this offering). WGRAH received a $2.2 billion loan from an entity owned by Anadarko and a group of third-party investors pursuant to a loan agreement that has an initial term of five years and contains various affirmative and negative covenants. One of the covenants requires WGRAH to reduce its debt to EBITDA ratio incrementally over the life of the loan. Although WGRAH may elect to satisfy its obligations under the financing by divesting its midstream assets over time, these divestitures may be made to third parties rather than to us. This financing could reduce the willingness of Anadarko to contribute assets to us for non-cash consideration.

If we are unable to make accretive acquisitions from Anadarko or third parties, either because we are (i) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts, (ii) unable to obtain financing for these acquisitions on economically acceptable terms or (iii) outbid by competitors, then our future growth and ability to increase distributions will be limited. Furthermore, even if we do make acquisitions that we believe will be accretive, these acquisitions may nevertheless result in a decrease in the cash generated from operations on a per unit basis.

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

- mistaken assumptions about volumes, revenues and costs, including synergies;
- an inability to successfully integrate the assets or businesses we acquire;
- the assumption of unknown liabilities;

Table of Contents

Risk factors

- limitations on rights to indemnity from the seller;
- mistaken assumptions about the overall costs of equity or debt;
- the diversion of management s and employees attention from other business concerns;
- unforeseen difficulties operating in new geographic areas; and
- customer or key employee losses at the acquired businesses.

If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and you 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.

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

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

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 gathering, compressing, treating and transportation of natural gas, including:

- damage to pipelines and plants, related equipment and surrounding properties caused by hurricanes, tornadoes, floods, fires and other natural disasters and acts of terrorism;
- inadvertent damage from 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;
- leaks of natural gas containing hazardous quantities of hydrogen sulfide from our Pinnacle gathering system or Bethel treating facility;
- fires and explosions; and
- other hazards that could also result in personal injury and loss of life, pollution and suspension of operations.

These risks could result in substantial losses due to personal injury and/or loss of life, severe 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. For example, we do not have any property insurance on any of our underground pipeline systems that would cover damage to the pipelines. In addition, although we are insured for environmental pollution resulting from environmental accidents that occur on a sudden and accidental basis, we may not be insured against all environmental accidents that might incur, 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 adversely affect our operations and financial condition. Furthermore, we may not be able to maintain or obtain insurance of the type and amount we desire at

Risk factors

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.

We are exposed to the credit risk of Anadarko, and any material non-payment or non-performance by Anadarko, including with respect to our gathering and transportation agreements and our $337.6 million note receivable, could reduce our ability to make distributions to our unitholders.

We are dependent on Anadarko for the majority of our revenues. In addition, we anticipate using the proceeds of this offering to make a loan to Anadarko. Consequently, we are subject to the risk of non-payment or non-performance by Anadarko, including with respect to our gathering and transportation agreements and our $337.6 million note receivable. Any such non-payment or non-performance could reduce our ability to make distributions to our unitholders. Furthermore, Anadarko is subject to its own financial, operating and regulatory risks, which could increase the risk of default on its obligations to us. We cannot predict the extent to which Anadarko s business would be impacted if conditions in the energy industry were to deteriorate nor can we estimate the impact such conditions would have on Anadarko s ability to perform under our gathering and transportation agreements or note receivable. Further, unless and until we receive full repayment of the $337.6 million note from Anadarko, we will be subject to the risk of non-payment or late payment of the interest payments and principal of the note. Interest income on the note receivable from Anadarko will be allocated in accordance with the general profit and loss allocation provisions included in our partnership agreement. Accordingly, any material non-payment or non-performance by Anadarko could reduce our ability to make distributions to our unitholders.

Anadarko s credit facility and other debt instruments contain financial and operating restrictions that may limit our access to credit. In addition, our ability to obtain credit in the future may be affected by Anadarko s credit rating.

We have the ability to incur up to $100 million of indebtedness under Anadarko s $750 million credit facility. However, this $100 million of borrowing capacity will be available to us only to the extent that sufficient amounts remain unborrowed by Anadarko. As a result, borrowings by Anadarko could restrict our access to credit. In addition, if we or Anadarko were to fail to comply with the terms of Anadarko s credit facility, we could be unable to make any borrowings under Anadarko s credit facility, even if capacity were otherwise available. As a result, the restrictions in Anadarko s credit facility could adversely affect our ability to finance our future operations or capital needs or to engage in, expand or pursue our business activities, and could also prevent us from engaging in certain transactions that might otherwise be considered beneficial to us.

Anadarko s and our ability to comply with the terms of Anadarko s debt instruments may be affected by events beyond its and our control, including prevailing economic, financial and industry conditions. If market or other economic conditions deteriorate, Anadarko s and our ability to comply with the terms of Anadarko s debt instruments may be impaired. We and Anadarko are subject to financial covenants and ratios under Anadarko s credit facility. Should we or Anadarko fail to comply with such financial covenants and ratios, we could be unable to make any borrowings under Anadarko s credit facility. Additionally, a default by Anadarko under one of Anadarko s debt instruments may cause a cross-default under Anadarko s other debt instruments, including the credit facility under which we are a co-borrower. Accordingly, a breach by Anadarko of certain of the covenants or ratios in another debt instrument could cause the acceleration of any indebtedness we have outstanding under the credit facility. In the event of an acceleration, we might not have, or be able to obtain, sufficient funds to

Risk factors

make the required repayments of debt, finance our operations and pay distributions to unitholders. For more information regarding our debt agreements, please read Management s discussion and analysis of financial condition and results of operations Liquidity and capital resources.

Due to our relationship with Anadarko, our ability to obtain credit will be affected by Anadarko s credit rating. Even if we obtain our own credit rating or separate financing arrangement, any future change in Anadarko s credit rating would likely also result in a change in our credit rating. Regardless of whether we have our own credit rating, a downgrading of Anadarko s credit rating could limit our ability to obtain financing in the future upon favorable terms or at all.

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.

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 may increase in the future to counter possible inflation. As a result, 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 our level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could have an adverse impact on our unit price, our ability to issue equity or incur debt for acquisitions or other purposes and our ability to make cash distributions at our intended levels.

RISKS INHERENT IN AN INVESTMENT IN US

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

Following this offering, Anadarko will own and control our general partner, as well as appoint all of the officers and directors of our general partner, some of whom will also be officers of Anadarko.

Risk factors

Although our general partner has a fiduciary 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 fiduciary duty to manage our general partner in a manner that is beneficial to its owner, Anadarko. Conflicts of interest may arise between Anadarko 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 Anadarko over our interests and the interests of our unitholders. These conflicts include the following situations, among others:

- Neither our partnership agreement nor any other agreement requires Anadarko to pursue a business strategy that favors us.
- Anadarko is not limited in its ability to compete with us and may offer business opportunities or sell midstream assets to parties other than us.
- Our general partner is allowed to take into account the interests of parties other than us, such as Anadarko, in resolving conflicts of interest.
- The officers of our general partner will also devote significant time to the business of Anadarko and will be compensated by Anadarko accordingly.
- Our partnership agreement limits the liability of and reduces the fiduciary duties owed by of our general partner, and also restricts the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty.
- Except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval.
- Our general partner determines the amount and timing of asset purchases and sales, borrowings, issuance of additional partnership securities and the creation, reduction or increase of reserves, each of which can affect the amount of cash that is distributed to our unitholders.
- Our general partner determines the amount and timing of any capital expenditures and whether a capital expenditure is classified as a maintenance capital expenditure, which reduces operating surplus, or an expansion capital expenditure, which does not reduce operating surplus. This determination can affect the amount of cash that is distributed to our unitholders and to our general partner and the ability of the subordinated units to convert to common units.
- Our general partner determines which costs incurred by it are reimbursable by us.
- Our general partner may cause us to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make a distribution on the subordinated units, to make incentive distributions or to accelerate the expiration of the subordination period.
- Our partnership agreement permits us to classify up to $27.1 million as operating surplus, even if it is generated from asset sales, non-working capital borrowings or other sources that would otherwise constitute capital surplus. This cash may be used to fund distributions on our subordinated units or to our general partner in respect of the

general partner interest or the incentive distribution rights.

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

- Our general partner intends to limit its liability regarding our contractual and other obligations.

- Our general partner may exercise its right to call and purchase all of the common units not owned by it and its affiliates if they own more than 80% of the common units.

- Our general partner controls the enforcement of the obligations that it and its affiliates owe to us.

Risk factors

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

Ø Our general partner may elect to cause us to issue Class B units to it in connection with a resetting of the target distribution levels related to our general partner s incentive distribution rights without the approval of the special committee of the board of directors of our general partner or our unitholders. This election may result in lower distributions to our common unitholders in certain situations.

Please read Conflicts of interest and fiduciary duties.

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

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

Cost reimbursements due to Anadarko 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 you. The amount and timing of such reimbursements will be determined by our general partner.

Prior to making distributions on our common units, we will reimburse our general partner and its affiliates for all expenses they incur on our behalf. These expenses will include all costs incurred by Anadarko and our general partner in managing and operating us. While our reimbursement of allocated general and administrative expenses is capped under the omnibus agreement, we are required to reimburse Anadarko and our general partner for all direct operating expenses incurred on our behalf. These direct operating expense reimbursements and the reimbursement of incremental general and administrative expenses we will incur as a result of becoming a publicly traded partnership are not capped. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us. The reimbursements to Anadarko and our general partner will reduce the amount of cash otherwise available for distribution to our unitholders.

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 fiduciary duties, even if we could have obtained more favorable terms without the limitation on liability. In addition, we are obligated to reimburse or indemnify our general partner to the extent that it incurs obligations on our behalf. Any such reimbursement or indemnification payments would reduce the amount of cash otherwise available for distribution to our unitholders.

30

Risk factors

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

We expect that we will distribute all of our available cash to our unitholders and will rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our acquisitions and expansion capital expenditures. As a result, to the extent we are unable to finance growth externally, our cash distribution policy will significantly impair our ability to grow. Furthermore, we anticipate using substantially all of the net proceeds of this offering to make a loan to Anadarko, and therefore, the net proceeds of this offering will not be directly used to grow our business.

In addition, because we distribute all of our available cash, our growth may not be as fast as that of businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our partnership agreement or in Anadarko s credit facility, under which we are a co-borrower, 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.

Our partnership agreement limits our general partner s fiduciary duties to holders of our common and subordinated units.

Our partnership agreement contains provisions that modify and reduce the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty law. 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, or otherwise free of fiduciary duties to us and our unitholders. This entitles our general partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our limited partners. Examples of decisions that our general partner may make in its individual capacity include:

Ø how to allocate corporate opportunities among us and its affiliates;

Ø whether to exercise its limited call right;

Ø how to exercise its voting rights with respect to the units it owns;

Ø whether to exercise its registration rights;

Ø whether to elect to reset target distribution levels; and

Ø whether or not to consent to any merger or consolidation of the partnership or amendment to the partnership agreement.

By purchasing a common unit, a common unitholder agrees to become bound by the provisions in the partnership agreement, including the provisions discussed above. Please read Conflicts of interest and fiduciary duties Fiduciary duties.

Risk factors

Our partnership agreement restricts the remedies available to holders of our common and subordinated units for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that restrict the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty under state fiduciary duty law. For example, our partnership agreement:

- provides that whenever our general partner makes a determination 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 believed that the decision was in the best interest of our partnership;

- 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; and

- provides that our general partner will not be in breach of its obligations under the partnership agreement or its fiduciary duties to us or our unitholders if a transaction with an affiliate or the resolution of a conflict of interest is:

  (a) approved by the special committee of the board of directors of our general partner, although our general partner is not obligated to seek such approval;

  (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;

  (c) on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or

  (d) fair and reasonable to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

In connection with a situation involving a transaction with an affiliate or a conflict of interest, any determination by our general partner must be made in good faith. If an affiliate transaction or the resolution of a conflict of interest is not approved by our common unitholders or the special committee and the board of directors of our general partner determines that the resolution or course of action taken with respect to the affiliate transaction or conflict of interest satisfies either of the standards set forth in subclauses (c) and (d) above, then it will be presumed that, in making its decision, the board of directors acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Table of Contents

Risk factors

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

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

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

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

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management s decisions regarding our business. Unitholders will have no right on an annual or ongoing basis to elect our general partner or its board of directors. The board of directors of our general partner will be chosen by Anadarko. Furthermore, if the unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price. Our partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders ability to influence the manner or direction of management.

Even if holders of our common units are dissatisfied, they cannot initially remove our general partner without its consent.

The unitholders initially will be unable to remove our general partner without its consent because our general partner and its affiliates will own sufficient units upon completion of this offering to be able to

Risk factors

prevent its removal. The vote of the holders of at least 662/3% of all outstanding limited partner units voting together as a single class is required to remove our general partner. Following the closing of this offering, Anadarko will own 58.5% of our outstanding common and subordinated 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 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 common units by prematurely eliminating their distribution and liquidation preference over our subordinated units, which would otherwise have continued until we had met certain distribution and performance 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 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 Anadarko 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 would then be in a position to replace the board of directors and officers of our general partner with its own designees and thereby exert significant control over the decisions made by the board of directors and officers.

You will experience immediate and substantial dilution in pro forma net tangible book value of $6.09 per common unit.

The estimated initial public offering price of $21.00 per common unit exceeds our pro forma net tangible book value of $14.91 per unit. Based on the estimated initial public offering price of $21.00 per common unit, you will incur immediate and substantial dilution of $6.09 per common unit. This dilution results primarily because the assets contributed by our general partner and its affiliates are recorded in accordance with GAAP at their historical cost, and not their fair value. Please read Dilution.

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

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

Ø our existing unitholders proportionate ownership interest in us will decrease;

Risk factors

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

Anadarko 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.

After the sale of the common units offered by this prospectus, assuming that the underwriters do not exercise their option to purchase additional common units, Anadarko will hold an aggregate of 3,823,925 common units and 22,573,925 subordinated units. All of the subordinated units will convert into common units at the end of the subordination period and may convert earlier under certain circumstances. 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.

Our general partner has a limited call right that may require you to sell your 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, you may be required to sell your common units at an undesirable time or price and may not receive any return on your investment. You may also incur a tax liability upon a sale of your units. At the completion of this offering, and assuming no exercise of the underwriters option to purchase additional common units, Anadarko will own approximately 16.9% of our outstanding common units. At the end of the subordination period, assuming no additional issuances of common units (other than upon the conversion of the subordinated units), Anadarko will own approximately 58.5% of our outstanding common units. For additional information about this right, please read The partnership agreement Limited call right.

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

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law, and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. You could be liable for any and all of our obligations as if you were a general partner if a court or government agency were to determine that:

- Ø we were conducting business in a state but had not complied with that particular state s partnership statute; or

- your right to act with other unitholders to remove or replace our general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute control of our business.

For a discussion of the implications of the limitations of liability on a unitholder, please read The partnership agreement Limited liability.

Risk factors

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 you 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.

There is no existing market for our common units, and a trading market that will provide you with adequate liquidity may not develop. The price of our common units may fluctuate significantly, and you could lose all or part of your investment.

Prior to this offering, there has been no public market for our common units. After this offering, there will be only 18,750,000 publicly traded common units, assuming no exercise of the underwriters option to purchase additional common units. In addition, Anadarko will own 3,823,925 common and 22,573,925 subordinated units, representing an aggregate 57.3% ownership interest in us. We do not know the extent to which investor interest will lead to the development of a trading market or how liquid that market might be. You may not be able to resell your common units at or above the initial public offering price. Additionally, the lack of liquidity may result in wide bid-ask spreads, contribute to significant fluctuations in the market price of the common units and limit the number of investors who are able to buy the common units.

The initial public offering price for the common units will be determined by negotiations between us and the representatives of the underwriters and may not be indicative of the market price of the common units that will prevail in the trading market. The market price of our common units may decline below the initial public offering price. The market price of our common units may also be influenced by many factors, some of which are beyond our control, including:

Ø our quarterly distributions;

Ø our quarterly or annual earnings or those of other companies in our industry;

Ø the loss of a large customer;

Ø announcements by us or our competitors of significant contracts or acquisitions;

Ø changes in accounting standards, policies, guidance, interpretations or principles;

Ø general economic conditions;

Ø

the failure of securities analysts to cover our common units after this offering or changes in financial estimates by analysts;

- Ø future sales of our common units; and
- Ø other factors described in these Risk factors.

We will incur increased costs as a result of being a publicly traded partnership.

We have no history operating as a publicly traded partnership. As a publicly traded partnership, we will incur significant legal, accounting and other expenses. In addition, the Sarbanes-Oxley Act of 2002 and related rules subsequently implemented by the SEC and the New York Stock Exchange, or the NYSE,

Risk factors

have required changes in the corporate governance practices of publicly traded companies. We expect these rules and regulations to increase our legal and financial compliance costs and to make activities more time-consuming and costly. For example, as a result of becoming a publicly traded partnership, we are required to have at least three independent directors, create an audit committee and adopt policies regarding internal controls and disclosure controls and procedures, including the preparation of reports on internal controls over financial reporting. In addition, we will incur additional costs associated with our publicly traded partnership reporting requirements. We also expect these new rules and regulations to make it more difficult and more expensive for our general partner to obtain director and officer liability insurance and to possibly result in our general partner having to accept reduced policy limits and coverage. As a result, it may be more difficult for our general partner to attract and retain qualified persons to serve on its board of directors or as executive officers. We have included $2.5 million of estimated incremental costs per year associated with being a publicly traded partnership in our financial forecast included elsewhere in this prospectus. However, it is possible that our actual incremental costs of being a publicly traded partnership will be higher than we currently estimate. These costs are not subject to the $6.0 million cap in the omnibus agreement applicable to general and administrative expenses allocable to us by Anadarko.

If we are deemed to be an investment company under the Investment Company Act of 1940, it would adversely affect the price of our common units and could have a material adverse effect on our business.

Our initial assets will consist of our ownership interests in our operating subsidiaries as well as a $337.6 million note receivable from Anadarko. If this note receivable together with a sufficient amount of our other assets are deemed to be investment securities, within the meaning of the Investment Company Act of 1940, or the Investment Company Act, we would either have to register as an investment company under the Investment Company Act, obtain exemptive relief from the SEC or modify our organizational structure or contract rights so as to fall outside of the definition of investment company. Registering as an investment company could, among other things, materially limit our ability to engage in transactions with affiliates, including the purchase and sale of certain securities or other property from or to our affiliates, restrict our ability to borrow funds or engage in other transactions involving leverage and require us to add additional directors who are independent of us or our affiliates. The occurrence of some or all of these events would adversely affect the price of our common units and could have a material adverse effect on our business.

Moreover, treatment of us as an investment company would prevent our qualification as a partnership for federal income tax purposes, in which case we would be treated as a corporation for federal income tax purposes. As a result, we would pay federal income tax on our taxable income at the corporate tax rate, distributions to you would generally be taxed again as corporate distributions and none of our income, gains, losses or deductions would flow through to you. If we were taxed as a corporation, our cash available for distribution to you would be substantially reduced. Therefore, treatment of us as an investment company 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. For a discussion of the federal income tax implications that would result from our treatment as a corporation in any taxable year, please read Material tax consequences Partnership status.

TAX RISKS TO COMMON UNITHOLDERS

In addition to reading the following risk factors, you should read Material tax consequences for a more complete discussion of the expected material federal income tax consequences of owning and disposing of common units.

Table of Contents

Risk factors

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 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 additional amounts of entity-level taxation for state tax purposes, then our cash available for distribution to you 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. 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.

Despite the fact that we are classified as a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. Although we do not believe, based upon our current operations, that we will be so treated, a change in our business (or a change in current law) could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

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 you would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to you. Because a tax would be imposed upon us as a corporation, our cash available for distribution to you 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.

Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. In addition, if we are deemed to be an investment company, as described above, we would be subject to such taxation. Moreover, at the federal level, legislation has been proposed that would eliminate partnership tax treatment for certain publicly traded partnerships. Although such legislation would not apply to us as currently proposed, it could be amended prior to enactment such that it would apply to us. We are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

At the state level, were we to be subject to federal income tax, we would also be subject to the income tax provisions of many states. Moreover, because of widespread state budget deficits and other reasons, several states are evaluating ways to independently subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Specifically, beginning in 2008, we will be required to pay Texas franchise tax at a maximum effective rate of 0.7% of our gross income apportioned to Texas in the prior year. Imposition of such a tax on us by Texas and, if applicable, by any other state will reduce the cash available for distribution to you.

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.

Risk factors

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

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury regulations, and, accordingly, our counsel is unable to opine as to the validity of this method. If the IRS were to challenge this method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders. Please read Material tax consequences Disposition of common units Allocations between transferors and transferees.

If the IRS contests the federal income tax positions we take or the pricing of our related party agreements with Anadarko, the market for our common units may be adversely impacted and the cost of any IRS contest will reduce our cash available for distribution to you.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us, including the pricing of our related party agreements with Anadarko. The IRS may adopt positions that differ from the conclusions of our counsel expressed in this prospectus or from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel s conclusions or the positions we take. A court may not agree with some or all of our counsel s conclusions or positions we take. For example, the IRS may reallocate items of income, deductions, credits or allowances between related parties if the IRS determines that such reallocation is necessary to prevent evasion of taxes or clearly to reflect the income of any such related parties. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. If the IRS were successful in any such challenge, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders and our general partner. Such a reallocation may require us and our unitholders to file amended tax returns. In addition, 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.

You will be required to pay taxes on your share of our income even if you do not receive any cash distributions from us.

Because our unitholders will be treated as partners to whom we will allocate taxable income which could be different in amount than the cash we distribute, you will be required to pay any federal income taxes and, in some cases, state and local income taxes on your share of our taxable income whether or not you receive cash distributions from us. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the actual tax liability that results from that income.

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

If you sell your common units, you will recognize a gain or loss equal to the difference between the amount realized and your tax basis in those common units. Because distributions in excess of your allocable share of our net taxable income decrease your tax basis in your common units, the amount, if any, of such prior excess distributions with respect to the units you sell will, in effect, become taxable income to you, if you sell such units at a price greater than your tax basis in those units, even if the price you receive is less than your original cost. Furthermore, a substantial portion of the amount

Risk factors

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 you sell your units, you may incur a tax liability in excess of the amount of cash you receive from the sale. Please read Material tax consequences Disposition of common units Recognition of gain or loss for a further discussion of the foregoing.

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. If you are a tax-exempt entity or a non-U.S. person, you should consult your tax advisor before investing in our common units.

We will 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.

Because we cannot match transferors and transferees of common units, we will adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. Our counsel is unable to opine on the validity of such filing positions. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. It also could affect the timing of these tax benefits or the amount of gain from your sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to your tax returns. Please read Material tax consequences Tax consequences of unit ownership Section 754 election for a further discussion of the effect of the depreciation and amortization positions we adopt.

We will adopt 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 will determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and 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.

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

We will be considered to have terminated 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. 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. Please read Material tax consequences Disposition of common units Constructive termination for a discussion of the consequences of our termination for federal income tax purposes.

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

In addition to federal income taxes, you will likely be subject to other taxes, including foreign, state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property, even if you do not live in any of those jurisdictions. You will likely be required to file foreign, state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, you may be subject to penalties for failure to comply with those requirements. We will initially own assets and conduct business in the states of Kansas, Oklahoma, Texas, Utah and Wyoming. Each of these states, other than Texas and Wyoming, currently imposes a personal income tax, and all of theses states also impose 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 that impose a personal income tax. It is your responsibility to file all U.S. federal, foreign, state and local tax returns. Our counsel has not rendered an opinion on the foreign, state or local tax consequences of an investment in our common units.

Table of Contents

Use of proceeds

We expect to receive gross proceeds of approximately $393.8 million from the issuance and sale of 18,750,000 common units offered by this prospectus. We will use these proceeds to (i) make a loan of $337.6 million to Anadarko in exchange for a 30-year note bearing interest at a fixed annual rate of 6.00%, (ii) reimburse Anadarko for $15.5 million of capital expenditures it incurred with respect to assets contributed to us, (iii) provide $10.0 million for general partnership purposes and (iv) pay underwriting discounts and a structuring fee totaling approximately $25.6 million and other estimated offering expenses of $5.0 million.

Our estimates assume an initial public offering price of $21.00 per common unit and no exercise of the underwriters option to purchase additional common units. An increase or decrease in the initial public offering price of $1.00 per common unit would cause the net proceeds from the offering, after deducting underwriting discounts and the structuring fee, to increase or decrease by $17.5 million. If the proceeds increase due to a higher initial public offering price, we will use the additional proceeds to reimburse Anadarko for capital expenditures it incurred with respect to the assets contributed to us. If the proceeds decrease due to a lower initial public offering price, we will, to the extent necessary, (i) decrease our reimbursement to Anadarko for capital expenditures it incurred with respect to assets contributed to us by up to $15.5 million, (ii) decrease the amount of cash retained for general partnership purposes by up to $10.0 million and then (iii) reduce the amount of our loan to Anadarko by the balance of such amount.

The proceeds from any exercise of the underwriters option to purchase additional common units will be used to reimburse Anadarko for capital expenditures it incurred with respect to the assets contributed to us.

Anadarko has informed us that the $337.6 million of proceeds that we loan to it, and other proceeds that it receives from this offering, will be used to repay a portion of the amount outstanding under the recently completed $2.2 billion financing entered into by WGRAH, and a portion of such proceeds will ultimately be paid to affiliates of UBS Securities LLC, Citigroup Global Markets Inc., Credit Suisse Securities (USA) LLC, Morgan Stanley & Co. Incorporated, J.P. Morgan Securities Inc., Lehman Brothers Inc., Banc of America Securities LLC, Goldman, Sachs & Co., Scotia Capital (USA) Inc. and Wachovia Capital Markets, LLC. Please read Underwriting Affiliations.

Table of Contents

Capitalization

The following table shows:

- Ø the historical capitalization of our Predecessor as of September 30, 2007; and

- Ø our pro forma as adjusted capitalization as of September 30, 2007, reflecting this offering of 18,750,000 common units at an assumed initial public offering price of $21.00, the other formation transactions described under Prospectus summary Formation transactions and partnership structure General and the application of the net proceeds from this offering as described under Use of proceeds.

We derived this table from, and it should be read in conjunction with and is qualified in its entirety by reference to, the historical and pro forma combined financial statements and the accompanying notes included elsewhere in this prospectus. You should also read this table in conjunction with Management s discussion and analysis of financial condition and results of operations.

	As of September 30, 2007	
	Historical	**Pro forma as adjusted[1]**
	(in millions)	
Debt	$	$
Total partners equity/parent net equity:		
Parent net equity	273.5	
Common units public[2][3]		363.2
Common units Anadarko[2][3]		46.0
Subordinated units Anadarko[3]		271.3
General partner units[2]		11.1
Total partners equity/parent net equity	273.5	691.6
Total capitalization	$ 273.5	$ 691.6

(1) *On a pro forma as adjusted basis, as of September 30, 2007, the public and Anadarko would have held 18,750,000 and 3,823,925 common units, respectively, Anadarko would have held 22,573,925 subordinated units and our general partner would have held 921,385 general partner units representing a 2.0% general partner interest in us.*

(2) *An increase or decrease in the initial public offering price of $1.00 per common unit would cause the public common unitholders capital to increase or decrease by $17.5 million. In the case of a $1.00 per common unit increase, Anadarko s partners capital would decrease by $17.5 million, and, in the case of a $1.00 per common unit decrease, Anadarko s partners capital would increase by $15.5 million.*

(3) A 1,000,000 unit increase in the number of common units issued to the public would result in an $19.6 million increase in the public common unitholders capital and an $19.6 million decrease in the partners capital of Anadarko.

Table of Contents

Dilution

Dilution is the amount by which the offering price paid by the purchasers of common units sold in this offering will exceed the pro forma net tangible book value per unit after the offering. On a pro forma basis as of September 30, 2007, after giving effect to the offering of common units and the application of the related net proceeds, and assuming the underwriters option to purchase additional common units is not exercised, our net tangible book value was $686.8 million, or $14.91 per unit. Net tangible book value excludes $4.8 million of net intangible assets. Purchasers of common units in this offering will experience substantial and immediate dilution in net tangible book value per common unit for financial accounting purposes, as illustrated in the following table:

Initial public offering price per common unit		$ 21.00
Net tangible book value per unit before the offering(1)	9.84	
Increase in net tangible book value per unit attributable to purchasers in the offering	5.07	
Less: Pro forma net tangible book value per unit after the offering(2)		14.91
Immediate dilution in tangible net book value per common unit to purchasers in the offering(3)		$ 6.09

(1) *Determined by dividing the number of units (3,823,925 common units, 22,573,925 subordinated units and 921,385 general partner units) to be issued to our general partner and its affiliates, including Anadarko, for the contribution of assets and liabilities to Western Gas Partners, LP into the net tangible book value of the contributed assets and liabilities.*

(2) *Determined by dividing the total number of units to be outstanding after the offering (22,573,925 common units, 22,573,925 subordinated units and 921,385 general partner units) into our pro forma net tangible book value, after giving effect to the application of the expected net proceeds of the offering.*

(3) *If the initial public offering price were to increase or decrease by $1.00 per common unit, then dilution in net tangible book value per common unit would equal $7.09 and $5.14, respectively.*

The following table sets forth the number of units that we will issue and the total consideration contributed to us by our general partner and its affiliates and by the purchasers of common units in this offering upon consummation of the transactions contemplated by this prospectus:

	Units acquired		**Total consideration**	
	Number	**Percent**	**Amount**	**Percent**
			(in thousands)	
General partner and affiliates(1)(2)(3)	27,319,235	59.3%	$ 257,976	39.6%
Purchasers in the offering	18,750,000	40.7%	393,750	60.4%
Total	46,069,235	100.0%	$ 651,726	100.0%

(1) The units acquired by our general partner and its affiliates, including Anadarko, consist of 3,823,925 common units, 22,573,925 subordinated units and 921,385 general partner units.

(2) The assets contributed by our general partner and its affiliates were recorded at historical cost in accordance with GAAP. Book value of the consideration provided by our general partner and its affiliates, as of September 30, 2007, equals parent net investment, which was $273.5 million, reduced by $15.5 million for reimbursement to Anadarko of capital expenditures it incurred with respect to assets contributed to us.

(3) Assumes the underwriters option to purchase additional common units is not exercised.

Table of Contents

Our cash distribution policy and restrictions on distributions

You should read the following discussion of our cash distribution policy in conjunction with the factors and assumptions upon which our cash distribution policy is based, which are included under the heading Assumptions and considerations. In addition, please read Forward-looking statements and Risk factors for information regarding statements that do not relate strictly to historical or current facts and certain risks inherent in our business. For additional information regarding our historical and pro forma operating results, you should refer to our historical and pro forma combined financial statements, and the notes thereto, included elsewhere in this prospectus.

GENERAL

Rationale for our cash distribution policy

Our partnership agreement requires us to distribute all of our available cash quarterly. Our cash distribution policy reflects a basic judgment that our unitholders will be better served by our distributing rather than retaining our available cash. Generally, our available cash is our cash on hand at the end of a quarter after the payment of our expenses and the establishment of cash reserves and cash on hand resulting from working capital borrowings made after the end of the quarter.

Limitations on cash distributions and our ability to change our cash distribution policy

There is no guarantee that our unitholders will receive quarterly distributions from us. We do not have a legal obligation to pay the minimum quarterly distribution or any other distribution except as provided in our partnership agreement. Our cash distribution policy may be changed at any time and is subject to certain restrictions, including the following:

- Our general partner will have the authority to establish reserves for the prudent conduct of our business and for future cash distributions to our unitholders, and the establishment or increase of those reserves could result in a reduction in cash distributions to you from the levels we currently anticipate pursuant to our stated distribution policy. Any determination to establish cash reserves made by our general partner in good faith will be binding on our unitholders. Our partnership agreement provides that in order for a determination by our general partner to be made in good faith, our general partner must believe that the determination is in our best interests.

- While our partnership agreement requires us to distribute all of our available cash, our partnership agreement, including the provisions requiring us to make cash distributions contained therein, may be amended. Our partnership agreement generally may not be amended during the subordination period without the approval of our public common unitholders. However, our partnership agreement can be amended with the consent of our general partner and the approval of a majority of the outstanding common units (including common units held by Anadarko) and the Class B units issued upon the reset of incentive distribution rights, if any, voting as a single class after the subordination period has ended. At the closing of this offering, Anadarko will own our general partner and approximately 58.5% of our outstanding common and subordinated units.

- Even if our cash distribution policy is not modified or revoked, the amount of distributions we pay under our cash distribution policy and the decision to make any distribution is determined by our general partner, taking into consideration the terms of our partnership agreement.

- Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to you if the distribution would cause our liabilities to exceed the fair value of our assets.

Our cash distribution policy and restrictions on distributions

- Ø We may lack sufficient cash to pay distributions to our unitholders due to increases in our operating or general and administrative expense, principal and interest payments on our debt, tax expenses, working capital requirements and anticipated cash needs.

Our ability to grow is dependent on our ability to access external expansion capital

We will distribute all of our available cash to our unitholders. As a result, we expect that we 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, Anadarko s credit facility, under which we are a co-borrower, or our working capital facility on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which in turn may impact the available cash that we have to distribute to our unitholders.

OUR MINIMUM QUARTERLY DISTRIBUTION

Upon completion of this offering, the board of directors of our general partner will adopt a policy pursuant to which we will declare a minimum quarterly distribution of $0.30 per unit per complete quarter, or $1.20 per unit per year, to be paid no later than 45 days after the end of each fiscal quarter through the quarter ending December 31, 2008. This equates to an aggregate cash distribution of $13.8 million per quarter, or $55.3 million per year, based on the number of common, subordinated and general partner units to be outstanding immediately after the completion of this offering.

If the underwriters do not exercise their option to purchase additional common units within the 30-day option period, we will issue 2,812,500 common units to Anadarko at the expiration of this period. If and to the extent the underwriters exercise their option to purchase additional common units, the number of units purchased by the underwriters pursuant to such exercise will be issued to the public and the remainder, if any, will be issued to Anadarko. Accordingly, the exercise of the underwriters option will not affect the total number of units outstanding or the amount of cash needed to pay the minimum quarterly distribution on all units. Please read Underwriting.

Initially, our general partner will be entitled to 2.0% of all distributions that we make prior to our liquidation. In the future, our general partner s initial 2.0% interest in these distributions may be reduced if we issue additional units and our general partner does not contribute a proportionate amount of capital to us to maintain its initial 2.0% general partner interest. The table below sets forth the assumed number of outstanding common, subordinated and general partner units upon the closing of this offering, assuming the underwriters do not exercise their option to purchase additional common units, and the aggregate distribution amounts payable on such units during the year following the closing of this offering at our minimum quarterly distribution rate of $0.30 per unit per quarter ($1.20 per unit on an annualized basis).

46

Our cash distribution policy and restrictions on distributions

		Minimum quarterly distributions	
	Number of units	One quarter	Annualized
Publicly held common units	18,750,000	$ 5,625,000	$ 22,500,000
Common units held by Anadarko[1]	3,823,925	1,147,178	4,588,710
Subordinated units held by Anadarko	22,573,925	6,772,178	27,088,710
General partner units held by our general partner	921,385	276,416	1,105,662
Total	46,069,235	$ 13,820,772	$ 55,283,082

(1) *Assumes the underwriters do not exercise their option to purchase 2,812,500 common units and that the 2,812,500 common units will be issued to Anadarko upon the expiration of the underwriters 30-day option period. Accordingly, irrespective of whether the underwriters exercise their option to purchase additional common units, the total number of common units we have outstanding upon the completion of this offering and the expiration of the option period will not be impacted.*

The subordination period generally will end if we have earned and paid at least $1.20 on each outstanding common and subordinated unit and the corresponding distribution on our general partner s 2.0% interest for each of three consecutive, non-overlapping four-quarter periods ending on or after March 31, 2011. If we have earned and paid at least $0.45 (150% of the minimum quarterly distribution, which is $1.80 on an annualized basis) on each outstanding common and subordinated unit and the corresponding distribution on our general partner s 2.0% interest for each quarter in any four-quarter period, the subordination period will terminate automatically and all of the subordinated units will convert into an equal number of common units. Please read the Provisions of our partnership agreement relating to cash distributions Subordination period.

If we do not pay the minimum quarterly distribution on our common units, our common unitholders will not be entitled to receive such payments in the future except during the subordination period. To the extent we have available cash in any future quarter during the subordination period in excess of the amount necessary to pay the minimum quarterly distribution to holders of our common units, we will use this excess available cash to pay any distribution arrearages related to prior quarters before any cash distribution is made to holders of subordinated units. Please read Provisions of our partnership agreement relating to cash distributions Subordination period.

Our cash distribution policy, as expressed in our partnership agreement, may not be modified or repealed without amending our partnership agreement. The actual amount of our cash distributions for any quarter is subject to fluctuations based on the amount of cash we generate from our business and the amount of reserves our general partner establishes in accordance with our partnership agreement as described above. We will pay our distributions on or about the 15th of each of February, May, August and November to holders of record on or about the 1st of each such month. If the distribution date does not fall on a business day, we will make the distribution on the business day immediately preceding the indicated distribution date. We will adjust the quarterly distribution for the period from the closing of this offering through March 31, 2008 based on the actual length of the period.

In the sections that follow, we present in detail the basis for our belief that we will be able to fully fund our minimum quarterly distribution of $0.30 per unit each quarter through the quarter ending December 31, 2008. In those sections, we present two tables, consisting of:

Ø Unaudited Pro Forma Available Cash, in which we present the amount of cash we would have had available for distribution on a pro forma basis for our fiscal year ended December 31, 2006 and the twelve months ended September 30, 2007, derived from our unaudited pro forma combined financial statements that are included in this prospectus, as adjusted to give pro forma effect to the offering and the formation transactions; and

Our cash distribution policy and restrictions on distributions

Ø Statement of Estimated Adjusted EBITDA, in which we demonstrate our ability to generate the minimum estimated Adjusted EBITDA necessary for us to pay the minimum quarterly distribution on all units for each quarter in the twelve months ending December 31, 2008.

UNAUDITED PRO FORMA AVAILABLE CASH FOR THE YEAR ENDED DECEMBER 31, 2006 AND THE TWELVE MONTHS ENDED SEPTEMBER 30, 2007

If we had completed the transactions contemplated in this prospectus on January 1, 2006, pro forma available cash generated for the year ended December 31, 2006 would have been approximately $63.3 million. This amount would have been sufficient to pay the minimum quarterly distribution on all of our common and subordinated units for such period.

If we had completed the transactions contemplated in this prospectus on October 1, 2006, our pro forma available cash generated for the twelve months ended September 30, 2007 would have been approximately $59.0 million. This amount would have been sufficient to pay the minimum quarterly distribution on all of our common and subordinated units for such period.

Unaudited pro forma available cash includes incremental revenue we expect to receive pursuant to the new gas gathering agreements we have entered into with Anadarko. These new gathering agreements include fees for gathering and treating that are higher than those reflected in our historical financial results.

Unaudited pro forma available cash also includes general and administrative expenses, which were calculated on a different basis as compared to historical periods. These general and administrative expenses are expected to total $8.5 million annually and consist of $6.0 million of general and administrative expenses allocated to us by Anadarko as well as $2.5 million of general and administrative expenses we expect to incur as a result of becoming a publicly traded partnership. Under the omnibus agreement, our reimbursement to Anadarko for certain general and administrative expenses it allocates to us will be capped at $6.0 million annually through December 31, 2009, subject to adjustments to reflect changes in the Consumer Price Index and, with the concurrence of the special committee of our general partner s board of directors, to reflect expansions of our operations through the acquisition or construction of new assets or businesses. Thereafter, our general partner will determine the general and administrative expenses to be reimbursed by us in accordance with our partnership agreement. The cap contained in the omnibus agreement does not apply to incremental general and administrative expenses we expect to incur or to be allocated to us as a result of becoming a publicly traded partnership. We currently expect those expenses to be approximately $2.5 million per year. Please read Certain relationships and related party transactions Agreements governing the transactions Omnibus agreement. General and administrative expenses related to being a publicly traded partnership include expenses associated with annual and quarterly reporting; tax return and Schedule K-1 preparation and distribution expenses; Sarbanes-Oxley compliance expenses; expenses associated with listing on the New York Stock Exchange; independent auditor fees; legal fees; investor relations expenses; and registrar and transfer agent fees. These expenses are not reflected in the historical combined financial statements of our Predecessor or our pro forma combined financial statements.

We based the pro forma adjustments upon currently available information and specific estimates and assumptions. The pro forma amounts below do not purport to present our results of operations had the transactions contemplated in this prospectus actually been completed as of the dates indicated. In addition, cash available to pay distributions is primarily a cash accounting concept, while our pro forma combined financial statements have been prepared on an accrual basis. As a result, you should view the amount of pro forma available cash only as a general indication of the amount of cash available to pay distributions that we might have generated had we been formed in earlier periods.

Table of Contents

Our cash distribution policy and restrictions on distributions

The following table illustrates, on a pro forma basis, for the year ended December 31, 2006 and for the twelve months ended September 30, 2007, the amount of cash that would have been available for distribution to our unitholders, assuming in each case that this offering had been consummated at the beginning of such period. Each of the pro forma adjustments presented below is explained in the footnotes to such adjustments.

PARTNERSHIP UNAUDITED PRO FORMA AVAILABLE CASH

	Year ended December 31, 2006	Twelve months ended September 30, 2007
	(in millions, except per unit data)	
Net income[(1)]:	$ 14.1	$ 21.7
Add:		
Other income (expense)	0.4	
Depreciation[(2)]	19.7	22.5
Income taxes[(2)]	6.2	12.5
Interest expense[(2)]	9.1	8.3
Adjusted EBITDA[(3)]:	49.5	65.0
Add:		
Pro forma net cash interest income[(4)]	20.3	20.3
Pro forma incremental Anadarko contract revenue[(5)]	38.5	28.0
Less:		
General and administrative expenses of being a publicly traded partnership[(6)]	2.5	2.5
Pro forma net cash interest expense[(7)]	0.2	0.2
Capital expenditures[(8)]	42.3	51.6
Pro forma available cash	$ 63.3	$ 59.0
Pro forma cash distributions		
Distributions per unit[(9)]	$ 1.20	$ 1.20
Distributions to public common unitholders[(9)]	$ 22.5	$ 22.5
Distributions to Anadarko and our general partner[(9)]	32.8	32.8
Total distributions	$ 55.3	$ 55.3
Excess	$ 8.0	$ 3.7

Percent of minimum quarterly distributions payable to common unitholders	100%	100%
Percent of minimum quarterly distributions payable to subordinated unitholders	100%	100%

(1) *Reflects pro forma net income of our Predecessor as if the acquisition of MIGC occurred on (i) January 1, 2006 for the year ended December 31, 2006 and (ii) October 1, 2006 for the twelve months ended September 30, 2007, derived from our Predecessor s combined financial statements.*

(2) *Reflects an adjustment to reconcile net income to Adjusted EBITDA.*

(3) *We define Adjusted EBITDA as net income (loss), plus interest expense, income taxes and depreciation, less interest income and other income (expense). For a reconciliation of Adjusted EBITDA to its most directly comparable financial measures calculated and presented in accordance with GAAP, please read Summary historical and pro forma financial and operating data Non-GAAP financial measure.*

Our cash distribution policy and restrictions on distributions

(4) Represents interest income we expect to receive annually with respect to the $337.6 million 30-year note bearing interest at a fixed annual rate of 6.00% that we will receive from Anadarko concurrently with the closing of this offering.

(5) Represents incremental revenue we expect to receive pursuant to the new gas gathering agreements we have entered into with Anadarko. These new gathering agreements include fees for gathering and treating that are higher than the fees reflected in our historical financial results. If the new gathering agreements had been in place for the year ended December 31, 2006 and the twelve months ended September 30, 2007, the average rate received for our gathering and treating volumes would have increased by $0.13/Mcf and $0.09/Mcf, respectively.

(6) Reflects an adjustment to our Adjusted EBITDA for estimated cash expenses associated with being a publicly traded partnership, such as expenses associated with annual and quarterly reporting; tax return and Schedule K-1 preparation and distribution expenses; Sarbanes-Oxley compliance expenses; expenses associated with listing on the New York Stock Exchange; independent auditor fees; legal fees; investor relations expenses; and registrar and transfer agent fees. We expect these expenses to total approximately $2.5 million per year.

(7) Represents estimated cash interest expense related to annual commitment fees of 0.175% on Anadarko s credit facility, under which we are a co-borrower, and our working capital facility.

(8) For the year ended December 31, 2006 and for the twelve months ended September 30, 2007, our capital expenditures were $42.3 million and $51.6 million, respectively. The capital expenditures are assumed to have occurred ratably throughout the year. For these periods, capital expenditures include both maintenance and expansion capital expenditures (excluding $18.0 million for compressor lease repurchases for the twelve months ended September 30, 2007) because we did not segregate these costs in historic periods. If we were able to isolate these costs, we would reflect borrowings to offset expansion capital expenditures and our pro forma available cash would be reduced by incremental interest expense on those borrowings as opposed to being reduced by the entire amount of such expansion capital expenditures in the table presented above. The $18.0 million for compressor lease repurchases was excluded because during the twelve months ended September 30, 2007, Anadarko exercised its early buyout option contained in three of its compressor leases, under which compressors were leased from a third party to Anadarko and subleased by Anadarko to us. Anadarko then transferred the compressors to us as a contribution to our capital. Absent this offering, these leases would have been refinanced and no capital expenditures would have been incurred.

(9) The table above is based on the assumption that the underwriters option has not been exercised and the 30-day option period for such exercise has expired. Set forth below is the assumed number of outstanding common, subordinated and general partner units upon the closing of this offering and expiration of the underwriters option period, and the aggregate distribution amounts payable on such units during the year following the closing of this offering at our minimum quarterly distribution rate of $0.30 per unit per quarter ($1.20 per unit on an annualized basis).

		Minimum quarterly distributions	
	Number of units	**One quarter**	**Annualized**

Publicly held common units	18,750,000	$ 5,625,000	$ 22,500,000
Common units held by Anadarko[a]	3,823,925	1,147,178	4,588,710
Subordinated units held by Anadarko	22,573,925	6,772,178	27,088,710
General partner units held by our general partner	921,385	276,416	1,105,662
Total	46,069,235	$ 13,820,772	$ 55,283,082

(a) *The number of common units held by Anadarko includes 2,812,500 common units subject to the underwriters option to purchase additional common units. If and to the extent this option is exercised, the remainder of these common units, if any, will be issued to Anadarko at the expiration of the underwriters option period.*

Our cash distribution policy and restrictions on distributions

ESTIMATED ADJUSTED EBITDA FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2008

Set forth below is a Statement of Estimated Adjusted EBITDA that reflects our ability to generate sufficient cash flow to pay the minimum quarterly distribution on all of our outstanding units for each quarter in the twelve months ending December 31, 2008. The financial forecast presents, to the best of our knowledge and belief, the expected results of operations, Adjusted EBITDA and cash available for distribution for the forecast period. We define Adjusted EBITDA as net income (loss), plus interest expense, income taxes, and depreciation, less interest income and other income (expense).
For a reconciliation of Adjusted EBITDA to its most directly comparable financial measures calculated and presented in accordance with GAAP, please read Summary historical and pro forma financial and operating data Non-GAAP financial measure.

Our minimum estimated Adjusted EBITDA reflects our judgment, as of the date of this prospectus, of conditions we expect to exist and the course of action we expect to take in order to pay the minimum quarterly distribution on all of our outstanding units and the corresponding distributions on our general partner s 2.0% interest for each quarter in the twelve months ending December 31, 2008. The assumptions discussed below under Assumptions and considerations are those that we believe are significant to our ability to generate our minimum estimated Adjusted EBITDA. We believe our actual results of operations and cash flows will be sufficient to generate the minimum estimated Adjusted EBITDA; however, we can give you no assurance that we will generate the minimum estimated Adjusted EBITDA. There will likely be differences between our minimum estimated Adjusted EBITDA and our actual results and those differences could be material. If we fail to generate the minimum estimated Adjusted EBITDA, we may not be able to pay the minimum quarterly distribution on our common units. In order to fund distributions to our unitholders at our initial rate of $1.20 per unit for the twelve months ending December 31, 2008, our minimum estimated Adjusted EBITDA for the twelve months ending December 31, 2008 must be at least $63.7 million.

We do not as a matter of course make public projections as to future operations, earnings or other results. However, management has prepared the minimum estimated Adjusted EBITDA and related assumptions set forth below to substantiate our belief that we will have sufficient available cash to pay the minimum quarterly distribution to all our unitholders for each quarter in the twelve months ending December 31, 2008. This forecast is a forward-looking statement and should be read together with the historical and pro forma combined financial statements and the accompanying notes included elsewhere in this prospectus and Management s discussion and analysis of financial condition and results of operations. The accompanying prospective financial information was not prepared with a view toward complying with the guidelines established by the American Institute of Certified Public Accountants with respect to prospective financial information, but, in the view of our management, was prepared on a reasonable basis, reflects the best currently available estimates and judgments, and presents, to the best of management s knowledge and belief, the assumptions on which we base our belief that we can generate the minimum estimated Adjusted EBITDA necessary for us to have sufficient cash available for distribution to pay the minimum quarterly distribution to all unitholders for each quarter in the twelve months ending December 31, 2008. However, this information is not fact and should not be relied upon as being necessarily indicative of future results, and readers of this prospectus are cautioned not to place undue reliance on the prospective financial information.

Neither our independent auditors nor any other independent accountants have compiled, examined or performed any procedures with respect to the prospective financial information contained herein, nor have they expressed any opinion or any other form of assurance on such information or its achievability, and they assume no responsibility for, and disclaim any association with, the prospective financial information.

When considering our financial forecast, you should keep in mind the risk factors and other cautionary statements under Risk factors. Any of the risks discussed in this prospectus, to the extent they are

Table of Contents

Our cash distribution policy and restrictions on distributions

realized, could cause our actual results of operations to vary significantly from those which would enable us to generate the minimum estimated Adjusted EBITDA.

We are providing the minimum estimated Adjusted EBITDA calculation to supplement our pro forma and historical combined financial statements in support of our belief that we will have sufficient available cash to pay the minimum quarterly distribution on all of our outstanding common and subordinated units for each quarter in the twelve months ending December 31, 2008. Please read below under Assumptions and considerations for further information as to the assumptions we have made for the financial forecast.

We do not undertake any obligation to release publicly the results of any future revisions we may make to the financial forecast or to update this financial forecast to reflect events or circumstances after the date of this prospectus. Therefore, you are cautioned not to place undue reliance on this information.

Table of Contents

Our cash distribution policy and restrictions on distributions

PARTNERSHIP STATEMENT OF ESTIMATED ADJUSTED EBITDA

		Twelve months ending December 31, 2008 (in millions)
Revenues		
Gathering and transportation of natural gas	$	121.0
Condensate		9.2
Natural gas and other		0.0
Total revenues		130.2
Costs and expenses		
Cost of product		4.2
Operating and maintenance expense		48.5
General and administrative expense		8.5
Depreciation and amortization expense		24.0
Total costs and expenses		85.2
Operating income		45.0
Interest expense		(0.4)
Interest income Anadarko note		20.3
Texas margin tax		(0.3)
Net income	$	64.6
Adjustments to reconcile net income to estimated Adjusted EBITDA:		
Add:		
Depreciation and amortization expense		24.0
Interest expense		0.4
Texas margin tax		0.3
Less:		
Interest income Anadarko note		(20.3)
Estimated Adjusted EBITDA[1]	$	69.0
Adjustments to reconcile estimated Adjusted EBITDA to estimated cash available for distribution:		
Less:		
Cash interest expense		0.4
Estimated expansion capital expenditures		15.9

Estimated maintenance capital expenditures		28.0
Texas margin tax		0.3
Add:		
Cash interest income Anadarko note		20.3
Cash on hand and borrowings for expansion capital expenditures		15.9
Estimated cash available for distribution	$	60.6
Aggregate annualized minimum quarterly distributions		55.3
Excess of cash available for distribution over aggregate annualized minimum quarterly distributions		5.3
Calculation of minimum estimated Adjusted EBITDA necessary to pay aggregate annualized minimum quarterly distributions:		
Estimated Adjusted EBITDA		69.0
Excess of cash available for distribution over minimum annual cash distributions		(5.3)
Minimum estimated Adjusted EBITDA necessary to pay aggregate annualized minimum quarterly distributions	$	63.7

(1) We define Adjusted EBITDA as net income (loss), plus interest expense, income taxes and depreciation, less interest income and other income (expenses). For a reconciliation of Adjusted EBITDA to its most directly comparable financial measures calculated and presented in accordance with GAAP, please read Summary historical and pro forma financial and operating data Non-GAAP financial measure.

Our cash distribution policy and restrictions on distributions

ASSUMPTIONS AND CONSIDERATIONS

We believe the assumptions and estimates we have made to demonstrate our ability to generate the minimum estimated Adjusted EBITDA, which are set forth below, are reasonable. We define Adjusted EBITDA as net income (loss), plus interest expense, income taxes and depreciation, less interest income and other income (expenses). For a reconciliation of Adjusted EBITDA to its most directly comparable financial measures calculated and presented in accordance with GAAP, please read Summary historical and pro forma financial and operating data Non-GAAP financial measure.

General considerations

- Revenues and operating expenses are net of intercompany transactions.

- Realized gathering throughput volume is the primary factor that will influence whether the amount of cash available for distribution for the twelve months ending December 31, 2008 is above or below our forecast. For example, if all other assumptions are held constant, a 5.0% decline in volumes below forecasted levels would result in a $5.0 million decline in revenues. Additionally, a 5.0% decline in the trading margin between condensate and natural gas would result in a $0.2 million decline in cash available for distribution. A decline in forecasted cash flow of greater than $5.3 million would result in our generating less than the minimum cash required to pay distributions.

- Transportation volumes are provided pursuant to firm and interruptible transportation arrangements.

Total operating revenue

We estimated total operating revenue for the twelve months ending December 31, 2008 based on the following significant assumptions:

- *Gathering and treating volumes.* We estimate that we will gather and/or treat an average of 812 MMcf/d of natural gas for the twelve months ending December 31, 2008 as compared to 845 MMcf/d for the year ended December 31, 2006 and 870 MMcf/d for the twelve months ended September 30, 2007. The decreased volumes estimated for the twelve months ending December 31, 2008 are primarily due to the end of an interim agreement for treating services on approximately 40 MMcf/d at our Pinnacle gas treating facility, together with the natural production declines from the wells connected to our systems, partially offset by new well connections.

- *Gathering and treating fees.* We estimate that we will receive an average gathering and treating fee of $0.34/Mcf for the twelve months ending December 31, 2008 as compared to $0.21/Mcf for the year ended December 31, 2006 and $0.25/Mcf for the twelve months ended September 30, 2007. The expected increase in our gathering and treating fees is due to the new gathering and treating agreements that we recently negotiated with Anadarko.

- *Gathering and treating revenues.* We estimate that gathering and treating revenues for the twelve months ending December 31, 2008 will be $102.1 million as compared to $65.0 million for the year ended December 31, 2006 and $78.1 million for the twelve months ended September 30, 2007.

The expected increase in gathering and treating revenues for the twelve months ending December 31, 2008 as compared to the year ended December 31, 2006 and the twelve months ended September 30, 2007 of approximately $37.1 million and $24.0 million, respectively, is primarily due to higher gathering and treating revenues of $39.8 million and $29.3 million, respectively, attributable to an increase of $0.13/Mcf and $0.09/Mcf, respectively, in average gathering and treating fees offset by a decrease of $2.7 million and $5.3 million, respectively, due to decreased average volumes.

Our higher gathering and treating revenues reflect the employee benefit costs specifically identified and associated with operational personnel working on our assets. All of these costs will be recovered

Our cash distribution policy and restrictions on distributions

by us following this offering through the gathering rates we will charge Anadarko under the new gas gathering agreements. For the year ended December 31, 2006 and the twelve months ended September 30, 2007, only those employee benefit costs reasonably allocated by Anadarko to us were included in and recovered through the gathering and treating fees we charged Anadarko.

- Ø *Transportation volumes.* We estimate that we will transport an average of 178 MMcf/d of natural gas for the twelve months ending December 31, 2008 as compared to 126 MMcf/d for the year ended December 31, 2006 and 134 MMcf/d for the twelve months ended September 30, 2007. The increase in forecasted volumes is primarily attributable to an additional 45 MMcf/d of firm capacity that was contracted for by Anadarko in connection with the recent expansion of the MIGC system. Our transportation volumes increased by an average of 71 Mcf/d as a result of the inclusion of MIGC for the full year ended December 31, 2006.

- Ø *Transportation fees.* We estimate that we will receive an average of $0.30/Mcf for the twelve months ended December 31, 2008 as compared to $0.37/Mcf for the year ended December 31, 2006 and $0.37/Mcf for the twelve months ended September 30, 2007. Our anticipated transportation fees are consistent with fees realized on a historical basis and contained in the FERC-approved rates for MIGC.

- Ø *Transportation revenues.* We estimate that transportation revenues for the twelve months ending December 31, 2008 will be $18.9 million as compared to $17.0 million for the year ended December 31, 2006 and $18.0 million for the twelve months ended September 30, 2007.

The expected increase in transportation revenues for the twelve months ending December 31, 2008 as compared to the year ended December 31, 2006 and the twelve months ended September 30, 2007 of approximately $1.9 million and $0.9 million, respectively, is primarily due to higher transportation revenues attributable to increased volumes, partially offset by lower rates.

- Ø *Condensate margin.* We estimate that we will receive an aggregate condensate margin of $5.0 million, based on revenues of $9.2 million and associated product costs of $4.2 million, for the twelve months ending December 31, 2008 as compared to $3.7 million for the year ended December 31, 2006 and $4.1 million for the twelve months ended September 30, 2007. The expected margin increase is due primarily to a higher forecasted spread between crude oil and natural gas prices in 2008 ($76.00/Bbl and $7.82/Mcf, respectively, based on NYMEX prices as of September 28, 2007) than existed in the year ended December 31, 2006 ($66.22/Bbl and $7.23/Mcf, respectively) and in the twelve months ended September 30, 2007 ($57.64/Bbl and $6.01/Mcf, respectively). Condensate margin is the difference between the revenue from sale of condensate recovered during the gathering of natural gas and the cost of the natural gas required to deliver the same thermal content to the shipper.

Operating and maintenance expense

We estimate that total operating and maintenance expense for the twelve months ending December 31, 2008 will be $48.5 million as compared to $43.9 million for the year ended December 31, 2006 and $43.8 million for the twelve months ended September 30, 2007. The expected increase in operating and maintenance expense for the twelve months ending December 31, 2008 as compared to the year ended December 31, 2006 and the twelve months ended September 30, 2007 of $4.6 million and $4.7 million, respectively, is primarily due to higher expected labor, maintenance and contract services costs. Operating and maintenance expense is comprised primarily of direct labor, insurance, property taxes, repair and maintenance, contract services, utility costs and services provided to us or on our behalf under our services and secondment agreement.

Our cash distribution policy and restrictions on distributions

Our higher expected labor expense is attributable to us bearing all of the employee benefit costs specifically identified and associated with the operational personnel working on our assets. For the year ended December 31, 2006 and the twelve months ended September 30, 2007, only those employee benefit costs reasonably allocated by Anadarko to us were included in and recovered through the gathering and treating fees we charged Anadarko. Under our new gas gathering agreements entered into with Anadarko, all of these costs will be recovered by us following the offering through the gathering rates we will charge Anadarko. As a result, our gathering and treating revenues will increase by an amount equal to the increase in operating and maintenance expense.

General and administrative expense

We estimate that general and administrative expense for the twelve months ending December 31, 2008 will be $8.5 million and will consist of $6.0 million of costs reimbursable to Anadarko for services performed on our behalf pursuant to the omnibus agreement and the services and secondment agreement and $2.5 million of general and administrative expense related to operating as a publicly traded partnership. General and administrative expense was $4.5 million and $3.7 million for the year ended December 31, 2006 and the twelve months ended September 30, 2007, respectively. The expected increase in general and administrative expense is driven by $2.5 million in costs associated with being a publicly traded partnership, with the balance of the increase attributable to increased corporate and management services associated with operating our business on a stand-alone basis.

We intend to grant approximately 24,000 phantom common units effective at the closing of this offering to the independent directors of our general partner pursuant to the Western Gas Partners, LP 2008 Long-Term Incentive Plan. These phantom units will vest 100% on the first anniversary of the date of the grant. Upon vesting, each phantom unit will entitle the holder to receive a common unit or, in the discretion of our general partner s board of directors, cash equal to the fair market value of a common unit. Holders of phantom units are entitled to distribution equivalents on a current basis. Holders of phantom units have no voting rights until such time as the phantom units become vested and common units are issued to such holders. We have not included a cash expense for these phantom units in the estimate of general and administrative expense for the twelve-month period ending December 31, 2008, nor have we included in our distribution coverage calculation distributions to be made in respect of such phantom units for the forecast period.

Depreciation and amortization expense

We estimate depreciation and amortization expense for the twelve months ending December 31, 2008 of $24.0 million as compared to $19.7 million for the year ended December 31, 2006 and $22.5 million for the twelve months ended September 30, 2007. Estimated depreciation and amortization expense reflects management s estimates, which are based on consistent average depreciable asset lives and depreciation methodologies. The increase in depreciation and amortization is attributable to an expected increase in capital investments in our assets.

Interest income and Texas margin tax

Interest income. We will loan $337.6 million of the net proceeds from this offering to Anadarko in exchange for an interest-only, 30-year note bearing interest at a fixed annual rate of 6.00%, resulting in interest income of $20.3 million during the twelve months ending December 31, 2008.

Texas margin tax. We estimate Texas margin tax payments for the twelve months ending December 31, 2008 will be $0.3 million based on a 1.0% tax rate on a maximum of 70% of our projected revenues attributable to operations in Texas for the year ending December 31, 2008.

Table of Contents

Our cash distribution policy and restrictions on distributions

Capital expenditures

We estimate total capital expenditures of $43.9 million for the twelve months ending December 31, 2008 as compared to $42.3 million and $51.6 million for the year ended December 31, 2006 and for the twelve months ended September 30, 2007, respectively. Historically, we did not make a distinction between maintenance and expansion capital expenditures. Our estimate is based on the following assumptions:

- Ø We estimate that maintenance capital expenditures for the twelve months ending December 31, 2008 will be $28.0 million. These expenditures are expected to include $13.0 million of well connection costs associated with maintaining throughput on our systems as well as approximately $5.0 million of one-time expenses at the Dew gathering facility and the Pinnacle gas treating facility to increase available compression. The remainder of the expenditures are primarily expected to be incurred to replace partially or fully depreciated assets and to overhaul existing assets.

- Ø We estimate that expansion capital expenditures for the twelve months ending December 31, 2008 will be $15.9 million. These expenditures are expected to include $11.5 million associated with the expansion of the sulfur treating capacity at our Bethel plant in East Texas that we expect to complete in 2008. We also expect to spend $3.4 million to add additional compression on our Dew gathering system in East Texas.

Financing

Our forecast for the twelve months ending December 31, 2008 is based on the following financing assumptions:

- Ø We expect to use $10 million of the net proceeds of this offering to finance a portion of our expansion capital expenditures during the forecast period.

- Ø We expect to finance the balance of our expansion capital expenditures of $5.9 million through borrowings under Anadarko s credit facility, under which we are a co-borrower, or our working capital facility.

- Ø Our average debt level will be $2.9 million, comprised of funds drawn either on Anadarko s credit facility, under which we are a co-borrower, or our working capital facility.

- Ø We estimate interest expense of $0.4 million for the twelve months ending December 31, 2008, which includes commitment fees of 0.175% on Anadarko s credit facility, under which we are a co-borrower, and our working capital facility and interest associated with funds expected to be drawn. We estimate our borrowings under Anadarko s credit facility and our working capital facility to bear an average annualized variable interest rate of 6.00% through December 31, 2008. An increase or decrease of 1.0% in the annual interest rate would not result in a material change to our annual interest expense.

- Ø Anadarko and we will remain in compliance with the financial and other covenants in the Anadarko credit facility and other debt instruments.

Regulatory, industry and economic factors

Our forecast for the twelve months ending December 31, 2008, is based on the following significant assumptions related to regulatory, industry and economic factors:

- Ø There will not be any new federal, state or local regulation of the midstream energy sector, or any new interpretation of existing regulations, that will be materially adverse to our business.

- Ø There will not be any major adverse change in the midstream energy sector or in market, insurance or general economic conditions.

Provisions of our partnership agreement relating to cash distributions

Set forth below is a summary of the significant provisions of our partnership agreement that relate to cash distributions.

DISTRIBUTIONS OF AVAILABLE CASH

General

Our partnership agreement requires that, within 45 days after the end of each quarter, beginning with the quarter ending March 31, 2008, we distribute all of our available cash to unitholders of record on the applicable record date. We will adjust the minimum quarterly distribution for the period from the closing of the offering through March 31, 2008.

Definition of available cash

Available cash, for any quarter, consists of all cash on hand at the end of that quarter:

Ø *less,* the amount of cash reserves established by our general partner to:

- provide for the proper conduct of our business;
- comply with applicable law, any of our debt instruments or other agreements; or
- provide funds for distributions to our unitholders for any one or more of the next four quarters;

Ø *plus*, if our general partner so determines, all or a portion of cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter.

Working capital borrowings are generally borrowings that are made under a credit facility, commercial paper facility or similar financing arrangement, and in all cases are used solely for working capital purposes or to pay distributions to partners and with the intent of the borrower to repay such borrowings within 12 months.

Intent to distribute the minimum quarterly distribution

We will distribute to the holders of common and subordinated units on a quarterly basis at least the minimum quarterly distribution of $0.30 per unit, or $1.20 per year, to the extent we have sufficient cash from our operations after establishment of cash reserves and payment of fees and expenses, including payments to our general partner. However, there is no guarantee that we will pay the minimum quarterly distribution on the units in any quarter. Even if our cash distribution policy is not modified or revoked, the amount of distributions paid under our policy and the decision to make any distribution is determined by our general partner, taking into consideration the terms of our partnership agreement.

General partner interest and incentive distribution rights

Initially, our general partner will be entitled to 2.0% of all quarterly distributions since inception that we make prior to our liquidation. This general partner interest will be represented by 921,385 general partner units. General partner units are not deemed outstanding units for purposes of voting rights and such units represent a non-voting general partner interest. Our general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its current general partner interest. Our general partner s initial 2.0% interest in our distributions may be reduced if we issue

58

Table of Contents

Provisions of our partnership agreement relating to cash distributions

additional limited partner units in the future and our general partner does not contribute a proportionate amount of capital to us to maintain its 2.0% general partner interest.

Our general partner also currently holds incentive distribution rights that entitle it to receive increasing percentages, up to a maximum of 50.0%, of the cash we distribute from operating surplus (as defined below) in excess of $0.45 per unit per quarter. The maximum distribution of 50.0% includes distributions paid to our general partner on its 2.0% general partner interest and assumes that our general partner maintains its general partner interest at 2.0%. The maximum distribution of 50.0% does not include any distributions that our general partner may receive on limited partner units that it owns.

OPERATING SURPLUS AND CAPITAL SURPLUS

General

All cash distributed to unitholders will be characterized as either operating surplus or capital surplus. Our partnership agreement requires that we distribute available cash from operating surplus differently than available cash from capital surplus.

Operating surplus

Operating surplus consists of:

Ø $27.1 million (as described below);

Ø all of our cash receipts after the closing of this offering, excluding cash from the following:

- borrowings that are not working capital borrowings;
- sales of equity and debt securities;
- sales or other dispositions of assets outside the ordinary course of business;
- the termination of interest rate swap agreements or commodity hedge contracts prior to the termination date specified herein;
- capital contributions received; and
- corporate reorganizations or restructurings; *plus*

Ø working capital borrowings made after the end of a quarter but on or before the date of determination of operating surplus for the quarter; *plus*

Ø cash distributions paid on equity issued to finance all or a portion of the construction, acquisition or improvement or replacement of a capital asset (such as equipment or facilities) during the period beginning on the date that we enter into a binding obligation to commence the construction, acquisition or improvement of a capital improvement or replacement of a capital asset and ending on the earlier to occur of the date the capital improvement or capital asset commences commercial service or the date that it is abandoned or disposed of; *less*

- all of our operating expenditures (as defined below) after the closing of this offering; *less*
- the amount of cash reserves established by our general partner to provide funds for future operating expenditures; *less*
- all working capital borrowings not repaid within twelve months after having been incurred or repaid within such twelve-month period with the proceeds of additional working capital borrowings.

As described above, operating surplus does not reflect actual cash on hand that is available for distribution to our unitholders. For example, it includes a provision that will enable us, if we choose, to distribute as operating surplus up to $27.1 million of cash we receive in the future from non-operating

Provisions of our partnership agreement relating to cash distributions

sources such as asset sales, issuances of securities and long-term borrowings that would otherwise be distributed as capital surplus. In addition, the effect of including, as described above, certain cash distributions on equity securities in operating surplus will be to increase operating surplus by the amount of any such cash distributions. As a result, we may also distribute as operating surplus up to the amount of any such cash distributions we receive from non-operating sources.

If a working capital borrowing, which increases operating surplus, is not repaid during the twelve-month period following the borrowing, it will be deemed repaid at the end of such period, thus decreasing operating surplus at such time. When such working capital borrowing is in fact repaid, it will not be treated as a further reduction in operating surplus because operating surplus will have been previously reduced by the deemed repayment.

We define operating expenditures in the glossary, and it generally means all of our cash expenditures, including, but not limited to, taxes, reimbursement of expenses to our general partner, reimbursement of expenses to Anadarko for services pursuant to the omnibus agreement or personnel provided to us under the services and secondment agreement, payments made in the ordinary course of business under interest rate swap agreements or commodity hedge contracts, manager and officer compensation, repayment of working capital borrowings, debt service payments and estimated maintenance capital expenditures (as discussed in further detail below), provided that operating expenditures will not include:

Ø repayment of working capital borrowings deducted from operating surplus pursuant to the last bullet point of the definition of operating surplus above when such repayment actually occurs;

Ø payments (including prepayments and prepayment penalties) of principal of and premium on indebtedness, other than working capital borrowings;

Ø expansion capital expenditures;

Ø actual maintenance capital expenditures (as discussed in further detail below);

Ø investment capital expenditures;

Ø payment of transaction expenses relating to interim capital transactions;

Ø distributions to our partners (including distributions in respect of our Class B units and incentive distribution rights); or

Ø non-pro rata purchases of units of any class made with the proceeds of a substantially concurrent equity issuance.

Capital surplus

Capital surplus consists of:

Ø borrowings other than working capital borrowings;

Ø sales of our equity and debt securities; and

- sales or other dispositions of assets for cash, other than inventory, accounts receivable and other current assets sold in the ordinary course of business or as part of normal retirement or replacement of assets.

Characterization of cash distributions

Our partnership agreement requires that we treat all available cash distributed as coming from operating surplus until the sum of all available cash distributed since the closing of this offering equals the operating surplus as of the most recent date of determination of available cash. Our partnership agreement requires that we treat any amount distributed in excess of operating surplus, regardless of its

Provisions of our partnership agreement relating to cash distributions

source, as capital surplus. We do not anticipate that we will make any distributions from capital surplus.

CAPITAL EXPENDITURES

For purposes of determining operating surplus, maintenance capital expenditures are those capital expenditures required to maintain our long-term operating capacity or operating income, and expansion capital expenditures are those capital expenditures that we expect will expand our operating capacity or operating income over the long term. Examples of maintenance capital expenditures include capital expenditures associated with the replacement of equipment and well connections, or the construction, development or acquisition of other facilities, to replace expected reductions in hydrocarbons available for gathering, compressing, treating, transporting or otherwise handled by our facilities (which we refer to as operating capacity). Maintenance capital expenditures will also include interest (and related fees) on debt incurred and distributions on equity issued to finance all or any portion of the construction, improvement or replacement of an asset that is paid in respect of the period that begins when we enter into a binding obligation to commence constructing or developing a replacement asset and ending on the earlier to occur of the date of any such replacement asset commences commercial service or the date that it is abandoned or disposed of. Capital expenditures made solely for investment purposes will not be considered maintenance capital expenditures.

Because our maintenance capital expenditures can be irregular, the amount of our actual maintenance capital expenditures may differ substantially from period to period, which could cause similar fluctuations in the amounts of operating surplus, adjusted operating surplus and cash available for distribution to our unitholders if we subtracted actual maintenance capital expenditures from operating surplus.

Our partnership agreement will require that an estimate of the average quarterly maintenance capital expenditures necessary to maintain our operating capacity or operating income over the long term be subtracted from operating surplus each quarter as opposed to the actual amounts spent. The amount of estimated maintenance capital expenditures deducted from operating surplus for those periods will be subject to review and change by our general partner at least once a year, provided that any change is approved by our special committee. The estimate will be made at least annually and whenever an event occurs that is likely to result in a material adjustment to the amount of our maintenance capital expenditures, such as a major acquisition or the introduction of new governmental regulations that will impact our business. For purposes of calculating operating surplus, any adjustment to this estimate will be prospective only. For a discussion of the amounts we have allocated toward estimated maintenance capital expenditures, please read Our cash distribution policy and restrictions on distributions.

The use of estimated maintenance capital expenditures in calculating operating surplus will have the following effects:

- it will reduce the risk that maintenance capital expenditures in any one quarter will be large enough to render operating surplus less than the initial quarterly distribution to be paid on all the units for the quarter and subsequent quarters;
- it will increase our ability to distribute as operating surplus cash we receive from non-operating sources; and
- it will be more difficult for us to raise our distribution above the minimum quarterly distribution and pay incentive distributions on the incentive distribution rights held by our general partner.

Expansion capital expenditures are those capital expenditures that we expect will increase our operating capacity or operating income. Examples of expansion capital expenditures include the acquisition of equipment, or the construction, development or acquisition of additional pipeline or treating capacity or new processing capacity, to the extent such capital expenditures are expected to expand our long-term

Provisions of our partnership agreement relating to cash distributions

operating capacity or operating income. Expansion capital expenditures will also include interest (and related fees) on debt incurred and distributions on equity issued to finance all or any portion of the construction of such capital improvement during the period that commences when we enter into a binding obligation to commence construction of a capital improvement and ending on the date any such capital improvement commences commercial service or the date that it is abandoned or disposed of. Capital expenditures made solely for investment purposes will not be considered expansion capital expenditures.

As described below, neither investment capital expenditures nor expansion capital expenditures are subtracted from operating surplus. Because expansion capital expenditures include interest payments (and related fees) on debt incurred and distributions on equity issued to finance all of the portion of the construction, replacement or improvement of a capital asset (such as gathering pipelines or treating facilities) during the period that begins when we enter into a binding obligation to commence construction of a capital improvement and ending on the earlier to occur of the date any such capital asset commences commercial service or the date that it is abandoned or disposed of, such interest payments and equity distributions are also not subtracted from operating surplus (except, in the case of maintenance capital expenditures, to the extent such interest payments and distributions are included in estimated maintenance capital expenditures).

Investment capital expenditures are those capital expenditures that are neither maintenance capital expenditures nor expansion capital expenditures. Investment capital expenditures largely will consist of capital expenditures made for investment purposes. Examples of investment capital expenditures include traditional capital expenditures for investment purposes, such as purchases of securities, as well as other capital expenditures that might be made in lieu of such traditional investment capital expenditures, such as the acquisition of a capital asset for investment purposes or development of facilities that are in excess of the maintenance of our existing operating capacity or operating income, but which are not expected to expand for more than the short term of our operating capacity or operating income.

Capital expenditures that are made in part for maintenance capital purposes and in part for investment capital or expansion capital purposes will be allocated as maintenance capital expenditures, investment capital expenditures or expansion capital expenditure by our general partner, with the concurrence of our special committee.

SUBORDINATION PERIOD

General

Our partnership agreement provides that, during the subordination period (which we define below), the common units will have the right to receive distributions of available cash from operating surplus each quarter in an amount equal to $0.30 per common unit, which amount is defined in our partnership agreement as the minimum quarterly distribution, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of available cash from operating surplus may be made on the subordinated units. These units are deemed subordinated because for a period of time, referred to as the subordination period, the subordinated units will not be entitled to receive any distributions until the common units have received the minimum quarterly distribution plus any arrearages from prior quarters. Furthermore, no arrearages will be paid on the subordinated units. The practical effect of the subordinated units is to increase the likelihood that during the subordination period there will be available cash to be distributed on the common units.

Table of Contents

Provisions of our partnership agreement relating to cash distributions

Subordination period

The subordination period will extend until the first business day of any quarter beginning after March 31, 2011, that each of the following tests are met:

- Ø distributions of available cash from operating surplus on each of the outstanding common units, subordinated units and general partner units equaled or exceeded the minimum quarterly distribution for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date;
- Ø the adjusted operating surplus (as defined below) generated during each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date equaled or exceeded the sum of the minimum quarterly distributions on all of the outstanding common, subordinated units and general partner units during those periods on a fully diluted basis during those periods; and
- Ø there are no arrearages in payment of the minimum quarterly distribution on the common units.

Early termination of subordination period

Notwithstanding the foregoing, the subordination period will automatically terminate and all of the subordinated units will convert into common units on a one-for-one basis if each of the following occurs:

- Ø distributions of available cash from operating surplus on each of the outstanding common units, subordinated units and general partner units equaled or exceeded $0.45 per quarter (150.0% of the minimum quarterly distribution) for each calendar quarter in the immediately preceding four-quarter period;
- Ø the adjusted operating surplus (as defined below) generated during each calendar quarter in the immediately preceding four-quarter period equaled or exceeded the sum of $0.45 (150.0% of the minimum quarterly distribution) on each of the outstanding common, subordinated and general partner units during that period on a fully diluted basis; and
- Ø there are no arrearages in payment of the minimum quarterly distributions on the common units.

Expiration of the subordination period

When the subordination period ends, each outstanding subordinated unit will convert into one common unit and will then participate pro-rata with the other common units in distributions of available cash. In addition, if the unitholders remove our general partner other than for cause and no units held by our general partner and its affiliates are voted in favor of such removal:

- Ø the subordination period will end and each subordinated unit will immediately convert into one common unit;
- Ø any existing arrearages in payment of the minimum quarterly distribution on the common units will be extinguished; and
- Ø

our general partner will have the right to convert its general partner units and its incentive distribution rights into common units or to receive cash in exchange for those interests.

Adjusted operating surplus

Adjusted operating surplus is intended to reflect the cash generated from operations during a particular period and therefore excludes net increases in working capital borrowings and net drawdowns of reserves of cash generated in prior periods. Adjusted operating surplus consists of:

Ø operating surplus generated with respect to that period; *less*

Ø any net increase in working capital borrowings with respect to that period; *less*

Provisions of our partnership agreement relating to cash distributions

- Ø any net decrease in cash reserves for operating expenditures with respect to that period not relating to an operating expenditure made with respect to that period; *plus*
- Ø any net decrease in working capital borrowings with respect to that period; *plus*
- Ø any net increase in cash reserves for operating expenditures with respect to that period required by any debt instrument for the repayment of principal, interest or premium.

DISTRIBUTIONS OF AVAILABLE CASH FROM OPERATING SURPLUS DURING THE SUBORDINATION PERIOD

Our partnership agreement requires that we make distributions of available cash from operating surplus for any quarter during the subordination period in the following manner:

- Ø *first*, 98.0% to the common unitholders, pro rata, and 2.0% to our general partner, until we distribute for each outstanding common unit an amount equal to the minimum quarterly distribution for that quarter;
- Ø *second*, 98.0% to the common unitholders, pro rata, and 2.0% to our general partner, until we distribute for each outstanding common unit an amount equal to any arrearages in payment of the minimum quarterly distribution on the common units for any prior quarters during the subordination period;
- Ø *third*, 98.0% to the subordinated unitholders, pro rata, and 2.0% to our general partner, until we distribute for each subordinated unit an amount equal to the minimum quarterly distribution for that quarter; and
- Ø *thereafter*, in the manner described in General partner interest and incentive distribution rights below.

The preceding discussion is based on the assumptions that our general partner maintains its 2.0% general partner interest and that we do not issue additional classes of equity securities.

PERCENTAGE ALLOCATIONS OF AVAILABLE CASH FROM OPERATING SURPLUS

The following table illustrates the percentage allocations of available cash from operating surplus between the unitholders and our general partner based on the specified target distribution levels. The amounts set forth under Marginal percentage interest in distributions are the percentage interests of our general partner and the unitholders in any available cash from operating surplus we distribute up to and including the corresponding amount in the column Total quarterly distribution per unit. The percentage interests shown for our unitholders and our general partner for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution. The percentage interests set forth below for our general partner include its 2.0% general partner interest and assume our general partner has contributed any additional capital to maintain its 2.0% general partner interest and has not transferred its incentive distribution rights.

	Marginal percentage interest in distributions(1)

	Total quarterly distribution per unit	Unitholders	General partner
Minimum Quarterly Distribution	$0.300	98.0%	2.0%
First Target Distribution	up to $0.345	98.0%	2.0%
Second Target Distribution	above $0.345 up to $0.375	85.0%	15.0%
Third Target Distribution	above $0.375 up to $0.450	75.0%	25.0%
Thereafter	above $0.450	50.0%	50.0%

Provisions of our partnership agreement relating to cash distributions

(1) Assumes that there are no arrearages on common units and that our general partner maintains its 2.0% general partner interest and continues to own the incentive distribution rights.

DISTRIBUTIONS OF AVAILABLE CASH FROM OPERATING SURPLUS AFTER THE SUBORDINATION PERIOD

Our partnership agreement requires that we make distributions of available cash from operating surplus for any quarter after the subordination period in the following manner:

- *first*, 98.0% to all unitholders, pro rata, and 2.0% to our general partner, until we distribute for each outstanding unit an amount equal to the minimum quarterly distribution for that quarter; and

- *thereafter*, in the manner described in General partner interest and incentive distribution rights below.

The preceding discussion is based on the assumptions that our general partner maintains its 2.0% general partner interest and that we do not issue additional classes of equity securities.

GENERAL PARTNER INTEREST AND INCENTIVE DISTRIBUTION RIGHTS

Our partnership agreement provides that our general partner initially will be entitled to 2.0% of all distributions that we make prior to our liquidation. Our general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its 2.0% general partner interest if we issue additional units. Our general partner s 2.0% interest, and the percentage of our cash distributions to which it is entitled, will be proportionately reduced if we issue additional units in the future and our general partner does not contribute a proportionate amount of capital to us in order to maintain its 2.0% general partner interest. Our general partner will be entitled to make a capital contribution in order to maintain its 2.0% general partner interest in the form of the contribution to us of common units based on the current market value of the contributed common units.

Incentive distribution rights represent the right to receive an increasing percentage (13.0%, 23.0% and 48.0%) of quarterly distributions of available cash from operating surplus after the minimum quarterly distribution and the target distribution levels have been achieved. Our general partner currently holds the incentive distribution rights, but may transfer these rights separately from its general partner interest, subject to restrictions in the partnership agreement.

The following discussion assumes that our general partner maintains its 2.0% general partner interest, that there are no arrearages on common units and that our general partner continues to own the incentive distribution rights.

If for any quarter:

- we have distributed available cash from operating surplus to the common and subordinated unitholders in an amount equal to the minimum quarterly distribution; and

- we have distributed available cash from operating surplus on outstanding common units in an amount necessary to eliminate any cumulative arrearages in payment of the minimum quarterly distribution;

then, our partnership agreement requires that we distribute any additional available cash from operating surplus for that quarter among the unitholders and the general partner in the following manner:

- Ø *first*, 98.0% to all unitholders, pro rata, and 2.0% to our general partner, until each unitholder receives a total of $0.345 per unit for that quarter (the first target distribution);
- Ø *second*, 85.0% to all unitholders, pro rata, and 15.0% to our general partner, until each unitholder receives a total of $0.375 per unit for that quarter (the second target distribution);

Provisions of our partnership agreement relating to cash distributions

- *third*, 75.0% to all unitholders, pro rata, and 25.0% to our general partner, until each unitholder receives a total of $0.45 per unit for that quarter (the third target distribution); and
- *thereafter*, 50.0% to all unitholders, pro rata, and 50.0% to our general partner.

GENERAL PARTNER S RIGHT TO RESET INCENTIVE DISTRIBUTION LEVELS

Our general partner, as the holder of our incentive distribution rights, has the right under our partnership agreement to elect to relinquish the right to receive incentive distribution payments based on the initial cash target distribution levels and to reset, at higher levels, the minimum quarterly distribution amount and cash target distribution levels upon which the incentive distribution payments to our general partner would be set. Our general partner s right to reset the minimum quarterly distribution amount and the target distribution levels upon which the incentive distributions payable to our general partner are based may be exercised, without approval of our unitholders or the special committee of our general partner, at any time when there are no subordinated units outstanding and we have made cash distributions to the holders of the incentive distribution rights at the highest level of incentive distribution for each of the prior four consecutive fiscal quarters. The reset minimum quarterly distribution amount and target distribution levels will be higher than the minimum quarterly distribution amount and the target distribution levels prior to the reset such that our general partner will not receive any incentive distributions under the reset target distribution levels until cash distributions per unit following this event increase as described below. We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would otherwise not be sufficiently accretive to cash distributions per common unit, taking into account the existing levels of incentive distribution payments being made to our general partner.

In connection with the resetting of the minimum quarterly distribution amount and the target distribution levels and the corresponding relinquishment by our general partner of incentive distribution payments based on the target cash distributions prior to the reset, our general partner will be entitled to receive a number of newly issued Class B units and general partner units based on a predetermined formula described below that takes into account the cash parity value of the average cash distributions related to the incentive distribution rights received by our general partner for the two quarters prior to the reset event as compared to the average cash distributions per common unit during this period. Our general partner will be issued the number of general partner units necessary to maintain our general partner s interest in us immediately prior to the reset election.

The number of Class B units that our general partner would be entitled to receive from us in connection with a resetting of the minimum quarterly distribution amount and the target distribution levels then in effect would be equal to the quotient determined by dividing (x) the average amount of cash distributions received by our general partner in respect of its incentive distribution rights during the two consecutive fiscal quarters ended immediately prior to the date of such reset election by (y) the average of the amount of cash distributed per common unit during each of these two quarters. Each Class B unit will be convertible into one common unit at the election of the holder of the Class B unit at any time following the first anniversary of the issuance of these Class B units.

Following a reset election by our general partner, the minimum quarterly distribution amount will be reset to an amount equal to the average cash distribution amount per unit for the two fiscal quarters immediately preceding the reset election (which amount we refer to as the reset minimum quarterly distribution) and the target distribution levels will be reset to be correspondingly higher such that we would distribute all of our available cash from operating surplus for each quarter thereafter as follows:

- Ø *first*, 98.0% to all unitholders, pro rata, and 2.0% to our general partner, until each unitholder receives an amount equal to 115.0% of the reset minimum quarterly distribution for that quarter;

Provisions of our partnership agreement relating to cash distributions

- *second*, 85.0% to all unitholders, pro rata, and 15.0% to our general partner, until each unitholder receives an amount per unit equal to 125.0% of the reset minimum quarterly distribution for the quarter;
- *third*, 75.0% to all unitholders, pro rata, and 25.0% to our general partner, until each unitholder receives an amount per unit equal to 150.0% of the reset minimum quarterly distribution for the quarter; and
- *thereafter*, 50.0% to all unitholders, pro rata, and 50.0% to our general partner.

The following table illustrates the percentage allocation of available cash from operating surplus between the unitholders and our general partner at various cash distribution levels (i) pursuant to the cash distribution provisions of our partnership agreement in effect at the closing of this offering, as well as (ii) following a hypothetical reset of the minimum quarterly distribution and target distribution levels based on the assumption that the average quarterly cash distribution amount per common unit during the two fiscal quarters immediately preceding the reset election was $0.60.

		Marginal percentage interest in distribution		
	Quarterly distribution per unit prior to reset	**Unitholders**	**General partner**	**Quarterly distribution per unit following hypothetical reset**
Minimum Quarterly Distribution	$0.300	98.0%	2.0%	$0.600
First Target Distribution	up to $0.345	98.0%	2.0%	up to $0.690(1)
Second Target Distribution	above $0.345 up to $0.375	85.0%	15.0%	above $0.690(1) up to $0.750(2)
Third Target Distribution	above $0.375 up to $0.450	75.0%	25.0%	above $0.750(2) up to $0.900(3)
Thereafter	above $0.450	50.0%	50.0%	above $0.900(3)

(1) *This amount is 115.0% of the hypothetical reset minimum quarterly distribution.*

(2) *This amount is 125.0% of the hypothetical reset minimum quarterly distribution.*

(3) *This amount is 150.0% of the hypothetical reset minimum quarterly distribution.*

The following table illustrates the total amount of available cash from operating surplus that would be distributed to the unitholders and our general partner, including in respect of incentive distribution rights, or IDRs, based on an average of the amounts distributed for a quarter for the two quarters immediately prior to the reset. The table assumes that immediately prior to the reset there are 45,147,850 common units outstanding, our general partner has maintained its 2.0% general partner interest, and the average distribution to each common unit is $0.60 for the two quarters prior to the reset.

	Quarterly distribution per unit prior to reset	Cash distributions to common unitholders prior to reset	Class B units	Cash distributions to general partner prior to reset: 2.0% general partner interest	Incentive distribution rights	Total	Total distributions
Minimum Quarterly Distribution	$0.300	$ 13,544,355	$	$ 276,415	$	$ 276,415	$ 13,820,770
First Target Distribution	up to $0.345	2,031,653		41,463		41,463	2,073,116
Second Target Distribution	above $0.345 up to $0.375	1,354,436		31,869	207,149	239,018	1,593,454
Third Target Distribution	above $0.375 up to $0.450	3,386,088		90,296	1,038,401	1,128,697	4,514,785
Thereafter	above $0.450	6,772,178		270,887	6,501,290	6,772,177	13,544,355
		$ 27,088,710	$	$ 710,930	$ 7,746,840	$ 8,457,770	$ 35,546,480

Table of Contents

Provisions of our partnership agreement relating to cash distributions

The following table illustrates the total amount of available cash from operating surplus that would be distributed to the unitholders and our general partner, including in respect of IDRs, with respect to the quarter in which the reset occurs. The table reflects that as a result of the reset there are 45,147,850 common units and 12,911,400 Class B units outstanding, our general partner s 2.0% interest has been maintained, and the average distribution to each common unit is $0.60. The number of Class B units to be issued to our general partner upon the reset was calculated by dividing (i) the average of the amounts received by our general partner in respect of its IDRs for the two quarters prior to the reset as shown in the table above, or $7,746,840, by (ii) the average available cash distributed on each common unit for the two quarters prior to the reset as shown in the table above, or $0.60.

	Quarterly distribution per unit after reset	Cash distributions to common unitholders after reset	Cash distributions to general partner after reset				
			Class B units	2.0% General partner interest	Incentive distribution rights	Total	Total distributions
Minimum Quarterly Distribution	$0.600	$ 27,088,710	$ 7,746,840	$ 710,930	$	$ 8,457,770	$ 35,546,480
First Target Distribution	up to $0.690						
Second Target Distribution	above $0.690 up to $0.750						
Third Target Distribution	above $0.750 up to $0.900						
Thereafter	above $0.900						
		$ 27,088,710	$ 7,746,840	$ 710,930	$	$ 8,457,770	$ 35,546,480

Our general partner will be entitled to cause the minimum quarterly distribution amount and the target distribution levels to be reset on more than one occasion, provided that it may not make a reset election except at a time when it has received incentive distributions for the prior four consecutive fiscal quarters based on the highest level of incentive distributions that it is entitled to receive under our partnership agreement.

DISTRIBUTIONS FROM CAPITAL SURPLUS

How distributions from capital surplus will be made

Our partnership agreement requires that we make distributions of available cash from capital surplus, if any, in the following manner:

- *first*, 98.0% to all unitholders, pro rata, and 2.0% to our general partner, until we distribute for each common unit that was issued in this offering, an amount of available cash from capital surplus equal to the initial public offering price;

- *second*, 98.0% to the common unitholders, pro rata, and 2.0% to our general partner, until we distribute for each common unit, an amount of available cash from capital surplus equal to any unpaid arrearages in payment of the minimum quarterly distribution on the common units; and

- *thereafter*, we will make all distributions of available cash from capital surplus as if they were from operating surplus.

Effect of a distribution from capital surplus

Our partnership agreement treats a distribution of capital surplus as the repayment of the initial unit price from this initial public offering, which is a return of capital. The initial public offering price less any distributions of capital surplus per unit is referred to as the unrecovered initial unit price. Each time a distribution of capital surplus is made, the minimum quarterly distribution and the target

Table of Contents

Provisions of our partnership agreement relating to cash distributions

distribution levels will be reduced in the same proportion as the corresponding reduction in the unrecovered initial unit price. Because distributions of capital surplus will reduce the minimum quarterly distribution after any of these distributions are made, it may be easier for our general partner to receive incentive distributions and for the subordinated units to convert into common units. However, any distribution of capital surplus before the unrecovered initial unit price is reduced to zero cannot be applied to the payment of the minimum quarterly distribution or any arrearages.

Once we distribute capital surplus on a unit issued in this offering in an amount equal to the initial unit price, our partnership agreement specifies that the minimum quarterly distribution and the target distribution levels will be reduced to zero. Our partnership agreement specifies that we then make all future distributions from operating surplus, with 50.0% being paid to the holders of units and 50.0% to our general partner. The percentage interests shown for our general partner include its 2.0% general partner interest and assume our general partner has not transferred the incentive distribution rights.

ADJUSTMENT TO THE MINIMUM QUARTERLY DISTRIBUTION AND TARGET DISTRIBUTION LEVELS

In addition to adjusting the minimum quarterly distribution and target distribution levels to reflect a distribution of capital surplus, if we combine our units into fewer units or subdivide our units into a greater number of units, our partnership agreement specifies that the following items will be proportionately adjusted:

Ø the minimum quarterly distribution;

Ø target distribution levels;

Ø the unrecovered initial unit price; and

Ø the number of common units into which a subordinated unit is convertible.

For example, if a two-for-one split of the common units should occur, the minimum quarterly distribution, the target distribution levels and the unrecovered initial unit price would each be reduced to 50% of its initial level, and each subordinated unit would be convertible into two common units. Our partnership agreement provides that we do not make any adjustment by reason of the issuance of additional units for cash or property.

In addition, if legislation is enacted or if existing law is modified or interpreted by a governmental taxing authority, so that we become taxable as a corporation or otherwise subject to taxation as an entity for federal, state or local income tax purposes, our partnership agreement specifies that the minimum quarterly distribution and the target distribution levels for each quarter may be reduced by multiplying each distribution level by a fraction, the numerator of which is available cash for that quarter and the denominator of which is the sum of available cash for that quarter plus our general partner s estimate of our aggregate liability for the quarter for such income taxes payable by reason of such legislation or interpretation. To the extent that the actual tax liability differs from the estimated tax liability for any quarter, the difference will be accounted for in subsequent quarters.

DISTRIBUTIONS OF CASH UPON LIQUIDATION

General

If we dissolve in accordance with the partnership agreement, we will sell or otherwise dispose of our assets in a process called liquidation. We will first apply the proceeds of liquidation to the payment of our creditors. We will distribute any remaining proceeds to the unitholders and the general partner, in accordance with their capital account balances, as adjusted to reflect any gain or loss upon the sale or other disposition of our assets in liquidation.

The allocations of gain and loss upon liquidation are intended, to the extent possible, to entitle the holders of outstanding common units to a preference over the holders of outstanding subordinated units

Provisions of our partnership agreement relating to cash distributions

upon our liquidation, to the extent required to permit common unitholders to receive their unrecovered initial unit price plus the minimum quarterly distribution for the quarter during which liquidation occurs plus any unpaid arrearages in payment of the minimum quarterly distribution on the common units. However, there may not be sufficient gain upon our liquidation to enable the holders of common units to fully recover all of these amounts, even though there may be cash available for distribution to the holders of subordinated units. Any further net gain recognized upon liquidation will be allocated in a manner that takes into account the incentive distribution rights of our general partner.

Manner of adjustments for gain

The manner of the adjustment for gain is set forth in the partnership agreement. If our liquidation occurs before the end of the subordination period, we will allocate any gain to the partners in the following manner:

- *first*, to our general partner and the holders of units who have negative balances in their capital accounts to the extent of and in proportion to those negative balances;

- *second*, 98.0% to the common unitholders, pro rata, and 2.0% to our general partner, until the capital account for each common unit is equal to the sum of: (1) the unrecovered initial unit price; (2) the amount of the minimum quarterly distribution for the quarter during which our liquidation occurs; and (3) any unpaid arrearages in payment of the minimum quarterly distribution;

- *third*, 98.0% to the subordinated unitholders, pro rata, and 2.0% to our general partner, until the capital account for each subordinated unit is equal to the sum of: (1) the unrecovered initial unit price; and (2) the amount of the minimum quarterly distribution for the quarter during which our liquidation occurs;

- *fourth*, 98.0% to all unitholders, pro rata, and 2.0% to our general partner, until we allocate under this paragraph an amount per unit equal to: (1) the sum of the excess of the first target distribution per unit over the minimum quarterly distribution per unit for each quarter of our existence; less (2) the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the minimum quarterly distribution per unit that we distributed 98.0% to the unitholders, pro rata, and 2.0% to our general partner, for each quarter of our existence;

- *fifth*, 85.0% to all unitholders, pro rata, and 15.0% to our general partner, until we allocate under this paragraph an amount per unit equal to: (1) the sum of the excess of the second target distribution per unit over the first target distribution per unit for each quarter of our existence; less (2) the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the first target distribution per unit that we distributed 85.0% to the unitholders, pro rata, and 15.0% to our general partner for each quarter of our existence;

- *sixth*, 75.0% to all unitholders, pro rata, and 25.0% to our general partner, until we allocate under this paragraph an amount per unit equal to: (1) the sum of the excess of the third target distribution per unit over the second target distribution per unit for each quarter of our existence; less (2) the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the second target distribution per unit that we distributed 75.0% to the unitholders, pro rata, and 25.0% to our general partner for each quarter of our existence; and

- *thereafter*, 50.0% to all unitholders, pro rata, and 50.0% to our general partner.

The percentage interests set forth above for our general partner include its 2.0% general partner interest and assume our general partner has not transferred the incentive distribution rights.

If the liquidation occurs after the end of the subordination period, the distinction between common and subordinated units will disappear, so that clause (3) of the second bullet point above and all of the third bullet point above will no longer be applicable.

Table of Contents

Provisions of our partnership agreement relating to cash distributions

Manner of adjustments for losses

If our liquidation occurs before the end of the subordination period, we will generally allocate any loss to our general partner and the unitholders in the following manner:

- *first*, 98.0% to holders of subordinated units in proportion to the positive balances in their capital accounts and 2.0% to our general partner, until the capital accounts of the subordinated unitholders have been reduced to zero;
- *second*, 98.0% to the holders of common units in proportion to the positive balances in their capital accounts and 2.0% to our general partner, until the capital accounts of the common unitholders have been reduced to zero; and
- *thereafter*, 100.0% to our general partner.

If the liquidation occurs after the end of the subordination period, the distinction between common and subordinated units will disappear, so that all of the first bullet point above will no longer be applicable.

Adjustments to capital accounts

Our partnership agreement requires that we make adjustments to capital accounts upon the issuance of additional units. In this regard, our partnership agreement specifies that we allocate any unrealized and, for tax purposes, unrecognized gain or loss resulting from the adjustments to the unitholders and the general partner in the same manner as we allocate gain or loss upon liquidation. In the event that we make positive adjustments to the capital accounts upon the issuance of additional units, our partnership agreement requires that we allocate any later negative adjustments to the capital accounts resulting from the issuance of additional units or upon our liquidation in a manner which results, to the extent possible, in the general partner s capital account balances equaling the amount which they would have been if no earlier positive adjustments to the capital accounts had been made.

Table of Contents

Selected historical and pro forma financial and operating data

The following table shows (i) the selected combined historical financial and operating data of our Predecessor, which are comprised of Anadarko Gathering Company and Pinnacle Gas Treating, Inc., with MIGC, Inc. (MIGC) reported as an acquired business of our Predecessor, and (ii) the selected combined pro forma as adjusted financial and operating data of the Partnership, for the periods and as of the dates indicated. The information in the following table should also be read together with Management s discussion and analysis of financial condition and results of operations.

Our Predecessor s selected combined historical balance sheet data as of December 31, 2006 and 2005 and selected combined historical statement of income and statement of cash flow data for the years ended December 31, 2006, 2005 and 2004 are derived from the audited historical combined financial statements of our Predecessor included elsewhere in this prospectus. Our Predecessor s selected combined historical balance sheet data as of December 31, 2004, 2003 and 2002 and selected combined historical statement of income for the years ended December 31, 2003 and 2002 are derived from the unaudited historical combined financial statements of our Predecessor not included in this prospectus. Our Predecessor s selected combined historical balance sheet data as of September 30, 2007 and selected combined historical statement of income and statement of cash flow data for the nine months ended September 30, 2007 and 2006 are derived from the unaudited historical combined financial statements of our Predecessor included elsewhere in this prospectus. Our Predecessor s selected combined historical balance sheet data as of September 30, 2006 are derived from the unaudited historical financial statements of our Predecessor not included in this prospectus.

The Partnership s selected combined pro forma as adjusted statement of income data for the year ended December 31, 2006 and the nine months ended September 30, 2007 and selected combined pro forma as adjusted balance sheet data as of September 30, 2007 are derived from the unaudited pro forma combined financial statements of the Partnership included elsewhere in this prospectus.

The pro forma adjustments have been prepared as if the acquisition of MIGC by our Predecessor occurred on January 1, 2006 and as if certain transactions to be effected at the closing of this offering had taken place on September 30, 2007, in the case of the pro forma balance sheet, and on January 1, 2006, in the case of the pro forma statements of operations for the year ended December 31, 2006 and the nine months ended September 30, 2007. These transactions include:

- the receipt by the Partnership of gross proceeds of $393.8 million from the issuance and sale of 18,750,000 common units at an assumed initial offering price of $21.00 per unit;
- the use of the proceeds from this offering to pay underwriting discounts and a structuring fee totaling approximately $25.6 million and other estimated offering expenses of $5.0 million; and
- the use of the remaining $363.2 million of aggregate net proceeds of this offering to (i) make a loan of $337.6 million to Anadarko in exchange for a 30-year note bearing interest at a fixed annual rate of 6.00%, (ii) reimburse Anadarko for $15.5 million of capital expenditures it incurred with respect to assets contributed to us and (iii) provide $10.0 million for general partnership purposes.

The following table includes our Predecessor s historical and our pro forma Adjusted EBITDA, which have not been prepared in accordance with GAAP. Adjusted EBITDA is presented because it is helpful to management, industry analysts, investors, lenders and rating agencies and may be used to assess the financial performance and operating results of our fundamental business activities. For a reconciliation of Adjusted EBITDA to its most directly comparable financial measures calculated and presented in accordance with GAAP, please read Summary historical and pro forma financial and operating data Non-GAAP financial measure.

72

Selected historical and pro forma financial and operating data

	Predecessor combined							Partnership pro forma as adjusted	
	Year ended December 31,					Nine months ended September 30,		Nine months ended September 30,	Year ended December 31,
	2006	2005	2004	2003	2002	2007	2006	2007	2006
	(in thousands, except operating and per unit data)								
tatement of ncome Data:									
otal revenues	$ 81,152	$ 71,650	$ 68,049	$ 61,401	$ 50,266	$ 85,513	$ 57,481	$ 85,513	$ 93,304
osts and xpenses	39,960	35,720	31,301	33,804	31,135	33,184	29,057	33,184	43,857
epreciation	18,009	15,447	14,841	14,294	16,509	17,104	12,635	17,104	19,710
otal operating xpenses	57,969	51,167	46,142	48,098	47,644	50,288	41,692	50,288	63,567
perating income	23,183	20,483	21,907	13,303	2,622	35,225	15,789	35,225	29,737
ther expense ncome)	26	(66)					25		377
nterest expense ncome)	9,631	8,650	7,146	6,782	9,019	6,643	7,943	(15,022)	(20,030
ncome tax xpense (benefit)	3,814	4,789	5,504	2,529	(2,331)	10,469	1,740	160	978
hange in ccounting rinciple				1,510					
et income (loss)	$ 9,712	$ 7,110	$ 9,257	$ 5,502	$ (4,066)	$ 18,113	$ 6,081	$ 50,087	$ 48,412
eneral partner terest in pro rma net income								1,315	968
ommon nitholders terest in pro rma net income								24,386	27,089
								24,386	20,355

ubordinated nitholders nterest in pro orma net income									
Net income per ommon unit basic and diluted)								$ 1.08	$ 1.20
Net income per ubordinated unit basic and diluted)								$ 1.08	$ 0.90
alance Sheet Data (at period nd):									
Net, property, lant and quipment	$ 310,871	$ 200,451	$ 196,065	$ 192,415	$ 200,398	$ 353,294	$ 302,057	$ 353,294	
otal assets	332,228	206,373	199,110	195,747	203,623	360,692	324,772	708,306	
otal partners apital/parent net quity	238,531	160,585	162,542	167,881	175,886	273,507	234,063	691,561	

73

Table of Contents

Selected historical and pro forma financial and operating data

	Predecessor combined							Partnership pro forma as adjusted	
	Year ended December 31,					Nine months ended September 30,		Nine months ended September 30,	Year ended December 31,
	2006	2005	2004	2003	2002	2007	2006	2007	2006
	(in thousands, except operating and per unit data)								
Cash Flow Data:									
Net cash provided by (used in):									
Operating activities	27,323	30,131	31,160			41,810	12,941		
Investing activities	(42,713)	(21,076)	(16,548)			(37,247)	(27,952)		
Financing activities	15,844	(9,067)	(14,596)			(5,021)	15,007		
Adjusted EBITDA(1)	41,192	35,930	36,748			52,329	28,424	52,329	49,447
Capital expenditures, net	42,299	20,841	16,548			37,020	27,709		
Operating Data:									
Affiliate									
Throughput, MMBtu/d	820	757	715	667	700	904	778	904	878
Average rate per MMBtu	$ 0.22	$ 0.21	$ 0.21	$ 0.19	$ 0.17	$ 0.28	$ 0.22	$ 0.28	$ 0.23
Third Party									
Throughput, MMBtu/d	72	41	31	32	15	90	64	90	93
Average rate per MMBtu	$ 0.19	$ 0.16	$ 0.13	$ 0.09	$ 0.14	$ 0.25	$ 0.21	$ 0.25	$ 0.23
Total									
Throughput, MMBtu/d	892	798	746	699	715	994	842	994	971
Average rate per MMBtu	$ 0.21	$ 0.21	$ 0.21	$ 0.18	$ 0.16	$ 0.28	$ 0.22	$ 0.28	$ 0.23

(1) *Adjusted EBITDA is defined in Summary historical and pro forma financial and operating data Non-GAAP financial measure. For a reconciliation of Adjusted EBITDA to their most directly comparable financial measures calculated and presented in accordance with GAAP, please read Summary historical and pro forma financial and operating data Non-GAAP financial measure.*

Table of Contents

Management s discussion and analysis of financial condition and results of operations

The historical combined financial statements included in this prospectus reflect the assets, liabilities and operations of our Predecessor, which is comprised of Anadarko Gathering Company (AGC) and Pinnacle Gas Treating, Inc. (PGT), with MIGC, Inc. (MIGC) reported as an acquired business of our Predecessor. All of the assets, liabilities and operations of our Predecessor will be contributed to us by Anadarko upon the closing of this offering. The following discussion analyzes the financial condition and results of operations of our Predecessor. You should read the following discussion and analysis of financial condition and results of operations in conjunction with the historical and pro forma combined financial statements, and the notes thereto, included elsewhere in this prospectus. For ease of reference, we refer to the historical financial results of our Predecessor as being our historical financial results.

OVERVIEW

We are a growth-oriented Delaware limited partnership recently formed by Anadarko to own, operate, acquire and develop midstream energy assets. We currently operate in East Texas, the Rocky Mountains, the Mid-Continent and West Texas and are engaged in the business of gathering, compressing, treating and transporting natural gas for our ultimate parent, Anadarko, and third-party producers and customers.

OUR OPERATIONS

Our results are driven primarily by the volumes of natural gas we gather, compress, treat and transport through our systems. For the nine months ended September 30, 2007, approximately 84% of our revenues were derived from gathering, compression and treating activities and 16% was derived from transportation activities. Approximately 9% of our gathering, compression and treating revenues were comprised of revenues from condensate sales. For the nine months ended September 30, 2007, 89% of our total revenues were generated by transactions with Anadarko.

In our gathering operations, we contract with producers to gather natural gas from individual wells located near our gathering systems. We connect wells to gathering lines through which natural gas may be compressed and delivered to a processing plant, treating facility or downstream pipeline, and ultimately to end-users. We also treat a significant portion of the natural gas that we gather so that it will meet required specifications for pipeline transportation.

We have secured a significant dedication from our largest customer, Anadarko, in order to maintain or increase our existing throughput levels and to offset the natural production declines of the wells currently connected to our gathering systems. Specifically, Anadarko has dedicated to us all of the natural gas production it owns or controls from (i) wells that are currently connected to our gathering systems, and (ii) additional wells that are drilled within one mile of connected wells or our gathering systems, as the systems currently exist and as they are expanded to connect additional wells in the future. As a result, this dedication will continue to expand as additional wells are connected to our gathering systems. Volumes associated with this dedication averaged approximately 736 MMBtu/d for the year ended December 31, 2006 and 738 MMBtu/d for the nine months ended September 30, 2007.

We generally do not take title to the natural gas that we gather, compress, treat or transport. We currently provide all of our gathering and treating services pursuant to fee-based contracts. Under these arrangements, we are paid a fixed fee based on the volume and thermal content of the natural gas we gather or treat. This type of contract provides us with a relatively steady revenue stream that is not subject to direct commodity price risk, except to the extent that we retain and sell condensate that is recovered during the gathering of natural gas from the wellhead. We have entered into new gathering

Management s discussion and analysis of financial condition and results of operations

contracts with Anadarko pursuant to which we will receive higher fees than we have historically realized. We have some indirect exposure to commodity price risk in that persistent low commodity prices may cause our current or potential customers to delay drilling or shut in production, which would reduce the volumes of natural gas available for gathering, compressing, treating and transporting by our systems. Please read Quantitative and qualitative disclosures about market risk below for a discussion of our exposure to commodity price risk through our condensate recovery and sales.

We provide a significant portion of our transportation services on our MIGC system through firm contracts that obligate our customers to pay a monthly reservation or demand charge, which is a fixed charge applied to firm contract capacity and owed by a customer regardless of the actual pipeline capacity used by that customer. When a customer uses the capacity it has reserved under these contracts, we are entitled to collect an additional commodity usage charge based on the actual volume of natural gas transported. These usage charges are typically a small percentage of the total revenues received from our firm capacity contracts. We also provide transportation services through interruptible contracts, pursuant to which a fee is charged to our customers based upon actual volumes transported through the pipeline.

HOW WE EVALUATE OUR OPERATIONS

Our management relies on certain financial and operational metrics to analyze our performance. These metrics are significant factors in assessing our operating results and profitability and include (1) throughput volumes, (2) operating expenses, (3) Adjusted EBITDA, and (4) distributable cash flow.

Throughput volumes

In order to maintain or increase throughput volumes on our gathering systems, we must connect additional wells to our systems. Our success in connecting additional wells is impacted by successful drilling activity on the acreage dedicated to our systems, our ability to secure volumes from new wells drilled on non-dedicated acreage and our ability to attract natural gas volumes currently gathered by our competitors.

To maintain and increase throughput volumes on our MIGC system, we must continue to contract our capacity to shippers, including producers and marketers, for transportation of their natural gas. We monitor producer and marketing activities in the area served by our transportation system to identify new opportunities.

Operating expenses

We analyze operating expenses to evaluate our performance. The primary components of our operating expenses that we evaluate include operation and maintenance expenses, cost of product expenses, general and administrative expenses and direct operating expenses. Certain of our operating expenses are classified based on whether the expenses are accrued for or paid to our affiliates or third-party vendors. Neither affiliate expenses nor third-party expenses bear a direct relationship to affiliate revenues or third-party revenues. For example, our third-party expenses are not those expenses necessary for generating our third-party revenues. Third-party expenses include all amounts accrued for or paid to third parties for the operation of our systems, whether in providing services to Anadarko or third parties, including utilities, field labor, measurement and analysis and other third-party disbursements.

Operation and maintenance expenses include, among other things, direct labor, insurance, repair and maintenance, contract services, utility costs and services provided to us or on our behalf under our services and secondment agreement.

Management s discussion and analysis of financial condition and results of operations

Cost of product expenses include (i) costs associated with the purchase of natural gas pursuant to the gas imbalance provisions contained in our contracts, (ii) costs associated with our obligation under certain contracts to redeliver a volume of natural gas to shippers which is thermally equivalent to condensate retained by us and sold to third parties and (iii) our fuel tracking mechanism, which tracks the difference between actual fuel usage and loss and amounts recovered for estimated fuel usage and loss under our contracts. These expenses are subject to variability. However, for the years ended December 31, 2006, 2005 and 2004, cost of product expenses comprised only 7.8%, 11.7% and 10.8% of total operating expenses, respectively. Thus, we do not expect the variability in our cost of product expenses to have a material impact on our overall results.

In our historical combined financial statements, general and administrative expenses included reimbursements of costs incurred by Anadarko on our behalf and allocations from Anadarko in the form of a management service fee in lieu of direct reimbursements for various corporate services. In the future, Anadarko will not receive a management services fee and we expect general and administrative expenses to be comprised primarily of amounts reimbursed by us to Anadarko pursuant to our omnibus agreement with Anadarko and expenses attributable to our status as a publicly traded partnership, such as expenses associated with annual and quarterly reporting; tax return and Schedule K-1 preparation and distribution expenses; Sarbanes-Oxley compliance expenses; expenses associated with listing on the New York Stock Exchange; independent auditor fees; legal fees; investor relations expenses; and registrar and transfer agent fees.

Pursuant to the omnibus agreement with Anadarko, we will reimburse Anadarko for allocated general and administrative expenses. The amount required to be reimbursed by us to Anadarko for certain allocated general and administrative expenses pursuant to the omnibus agreement will be capped at $6.0 million annually through December 31, 2009, subject to adjustment to reflect changes in the Consumer Price Index and, with the concurrence of the special committee of our general partner s board of directors, to reflect expansions of our operations through the acquisition or construction of new assets or businesses. Thereafter, our general partner will determine the general and administrative expenses to be reimbursed by us in accordance with our partnership agreement. The cap contained in the omnibus agreement does not apply to incremental general and administrative expenses we expect to incur or to be allocated to us as a result of becoming a publicly traded partnership. We currently expect those expenses to be approximately $2.5 million per year.

Adjusted EBITDA

We define Adjusted EBITDA as net income (loss), plus interest expense, income taxes and depreciation, less interest income and other income (expense). Adjusted EBITDA is not a presentation made in accordance with GAAP. For a reconciliation of Adjusted EBITDA to its most directly comparable financial measures calculated and presented in accordance with GAAP, please read Summary historical and pro forma financial and operating data Non-GAAP financial measure.

Distributable cash flow

We define distributable cash flow as Adjusted EBITDA, plus interest income, less net cash paid for interest expense, maintenance capital expenditures and income taxes. Distributable cash flow does not reflect changes in working capital balances. Distributable cash flow is not a presentation made in accordance with GAAP.

Table of Contents

Management s discussion and analysis of financial condition and results of operations

Adjusted EBITDA and distributable cash flow are supplemental financial measures that management and external users of our combined financial statements, such as industry analysts, investors, lenders and rating agencies, may use to assess:

- our operating performance as compared to other publicly traded partnerships in the midstream energy industry, without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate sufficient cash flow to make distributions to our unitholders; and
- the viability of acquisitions and capital expenditure projects and the returns on investment of various investment opportunities.

ITEMS AFFECTING THE COMPARABILITY OF OUR FINANCIAL RESULTS

Our historical results of operations for the periods presented below may not be comparable to our results of operations in the future for the reasons described below:

- We anticipate incurring approximately $2.5 million of general and administrative expenses attributable to operating as a publicly traded partnership, such as expenses associated with annual and quarterly reporting; tax return and Schedule K-1 preparation and distribution expenses; Sarbanes-Oxley compliance expenses; expenses associated with listing on the New York Stock Exchange; independent auditor fees; legal fees; investor relations expenses; and registrar and transfer agent fees. These incremental general and administrative expenses are not reflected in our historical or our pro forma combined financial statements.
- We anticipate incurring $6.0 million in general and administrative expenses to be allocated to us by Anadarko pursuant to the omnibus agreement. This amount is expected to be greater than the amount allocated to us by Anadarko for the management services fee and reflected in our historical combined financial statements.
- The impact of all affiliated transactions historically has been net settled within our combined financial statements because these transactions related to Anadarko and were funded by Anadarko s working capital. Third-party transactions were funded by our working capital. In the future, all affiliate and third-party transactions will be funded by our working capital. This will impact the comparability of our cash flow statements, working capital analysis and liquidity discussion.
- Prior to this offering, we incurred interest expense on intercompany notes payable to Anadarko. These balances were extinguished through non-cash transactions prior to this offering; therefore, interest expense attributable to these balances and reflected in our historical combined financial statements will not be incurred in future periods.
- We have entered into new gas gathering agreements with Anadarko which include fees for gathering and treating that are higher than those fees reflected in our historical financial results.
- Our combined financial statements reflect the gathering fees we historically charged Anadarko under our historic affiliate cost of service based arrangements. Under these arrangements, we recovered, on an annual basis, our operation and maintenance, general and administrative and depreciation expenses in addition to earning a return on our invested capital. Effective January 1, 2008, we entered into new 10-year gas gathering agreements with

Anadarko. Under the terms of these new agreements, we expect our operation and maintenance expense to increase as a result of us bearing all of the cost of employee benefits specifically identified and related to operational personnel working on our assets as compared to bearing only those employee benefit costs reasonably allocated by Anadarko to us in historic periods. Since our new gas gathering agreements are designed to fully recover these costs, our future revenues are expected to increase by an amount equal to the increase in operation and maintenance expense. Although we do not expect this change in methodology for computing affiliate gathering rates to impact our net cash flows or net income, we do expect this

Management s discussion and analysis of financial condition and results of operations

methodology change to impact the components thereof as compared to historic periods. If we applied the methodology employed under our new gas gathering agreements with Anadarko to historic periods, we estimate our gathering revenues and operation and maintenance expense for the years ended December 31, 2006, 2005, and 2004, would have increased by $2.8 million, $1.4 million and $0.9 million, respectively.

Ø Concurrently with the closing of this offering, we will loan $337.6 million to Anadarko in exchange for an interest-only, 30-year note bearing interest at a fixed annual rate of 6.00%. Interest income attributable to the note is not reflected in our historical combined financial statements, but will be included in our combined financial statements in the future.

Ø As a co-borrower under Anadarko s credit facility, we will incur an annual commitment fee of 0.175% of our committed and unused borrowing capacity of up to $100 million, or up to $175,000. In addition, Anadarko will enter into a working capital facility with us, under which we will incur an annual commitment fee of 0.175% of the unused portion of our committed borrowing capacity of $30 million, or up to $52,500.

Ø Our historical combined financial statements include U.S. federal and state income tax expense incurred by us. Due to our status as a partnership, we will not be subject to U.S. federal income tax and certain state income taxes in the future. However, we will make payments to Anadarko pursuant to a tax sharing agreement for our share of state and local income and other taxes that are included in combined or consolidated tax returns filed by Anadarko.

Ø Following the closing of this offering, we intend to make cash distributions to our unitholders and our general partner at an initial distribution rate of $0.30 per unit per quarter ($1.20 per unit on an annualized basis). Based on the terms of our cash distribution policy, we expect that we will distribute to our unitholders and our general partner most of the cash generated by our operations. As a result, we expect that we will rely upon external financing sources, including commercial bank borrowings and debt and equity issuances, to fund our acquisition and expansion capital expenditures. Historically, we largely relied on internally generated cash flows and capital contributions from Anadarko to satisfy our capital expenditure requirements.

GENERAL TRENDS AND OUTLOOK

We expect our business to continue to be affected by the following key trends. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about, or interpretations of, available information prove to be incorrect, our actual results may vary materially from our expected results.

Natural gas supply and demand

Natural gas continues to be a critical component of energy supply in the U.S. According to the Energy Information Administration, or EIA, total annual domestic consumption of natural gas is expected to increase from approximately 21.7 trillion cubic feet, or Tcf, in 2006 to approximately 24.7 Tcf in 2010. During the last three years, the U.S. has, on average, consumed approximately 22.0 Tcf per year, while total domestic production averaged approximately 18.4 Tcf per year during the same period. We believe that high natural gas prices and increasing demand will continue to drive an increase in natural gas drilling and production in the U.S. Natural gas reserves in the U.S. have increased overall in recent years, based on data obtained from the EIA.

There is a natural decline in production from existing wells, but in the areas in which we operate there is a significant level of drilling activity that can offset this decline. Although we anticipate continued high levels of exploration and production activities in all of the areas in which we operate, we have no

Management s discussion and analysis of financial condition and results of operations

control over this activity. Fluctuations in energy prices could affect production rates over time and levels of investment by Anadarko and third parties in exploration for and development of new natural gas reserves.

Rising operating costs and inflation

The current high level of natural gas exploration, development and production activities across the U.S. has resulted in increased competition for personnel and equipment. This is causing increases in the prices we pay for labor, supplies and property, plant and equipment. An increase in the general level of prices in the economy could have a similar effect. We attempt to recover increased costs from our customers, but there may be a delay in doing so or we may be unable to recover all these costs. To the extent we are unable to procure necessary supplies or recover higher costs, our operating results will be negatively impacted.

Impact of interest rates

Interest rates have been volatile in recent periods. If interest rates rise, our future financing costs will increase accordingly. In addition, because our common units are yield-based securities, rising market interest rates could impact the relative attractiveness of our common units to investors, which could limit our ability to raise funds, or increase the price of raising funds, in the capital markets. Though our competitors may face similar circumstances, such an environment could render us less competitive in our efforts to expand our operations or make future acquisitions.

Benefits from system expansions

We expect that expansion projects, including the following, will allow us to capitalize on increased drilling activity by Anadarko and other third-party producers:

Ø We installed additional compression on our Dew system, which added an incremental 16,537 horsepower in 2007 and anticipate adding an additional 2,680 of horsepower in 2008;

Ø We are expanding our Bethel treating facility by installing an additional 11 LTD of sulfur treating capacity in order to provide additional sour gas treating capacity for drilling in the area, which we expect to complete in 2008; and

Ø We are expanding our Hugoton gathering system.

Acquisition opportunities

We may acquire additional midstream energy assets from Anadarko. On December 27, 2007, Anadarko announced a $2.2 billion financing of its midstream assets which may require partial repayment based on a debt to EBITDA leverage ratio that declines incrementally over time. The debt repayments that may be necessary to satisfy the terms of this financing may be made with internally generated cash flow, cash on hand, or cash received from midstream asset sales. Should Anadarko choose to pursue midstream asset sales, it is under no contractual obligation to offer assets or business opportunities to us. In addition, we may also pursue selected asset acquisitions from third parties to the extent such acquisitions complement our or Anadarko s existing asset base or allow us to capture operational efficiencies from Anadarko s production. However, if we do not make acquisitions on economically acceptable terms, our future growth will be limited, and the acquisitions we do make may reduce, rather than increase, our cash generated from operations on a per-unit basis.

Management s discussion and analysis of financial condition and results of operations

RESULTS OF OPERATIONS COMBINED OVERVIEW

The following table and discussion presents a summary of our combined results of operations for the years ended December 31, 2006, 2005 and 2004 and for the nine months ended September 30, 2007 and 2006:

	Year ended December 31,			Nine months ended September 30,	
	2006	2005	2004	2007	2006
			(in thousands)		
Revenues-affiliates					
Gathering and transportation of natural gas	$ 65,946	$ 58,363	$ 54,407	$ 69,311	$ 46,546
Condensate	7,440	7,006	6,407	6,266	5,374
Natural gas and other	1,327	789	4,526	918	324
Total	74,713	66,158	65,340	76,495	52,244
Revenues-third parties					
Gathering and transportation of natural gas	5,022	2,420	1,458	6,067	3,660
Condensate, natural gas and other	1,417	3,072	1,251	2,951	1,577
Total	6,439	5,492	2,709	9,018	5,237
Total revenues	81,152	71,650	68,049	85,513	57,481
Operating expenses-affiliates					
Cost of product	3,830	5,551	4,425	4,439	4,196
General and administrative	3,198	2,829	2,251	2,370	2,394
Total	7,028	8,380	6,676	6,809	6,590
Operating expenses-third parties					
Cost of product	714	456	553		
Operation and maintenance(1)	27,585	23,044	20,678	21,840	18,598
General and administrative		9	48	751	204
Property and other taxes	4,633	3,831	3,346	3,784	3,665
Total	32,932	27,340	24,625	26,375	22,467
Depreciation	18,009	15,447	14,841	17,104	12,635
Total operating expenses	57,969	51,167	46,142	50,288	41,692

Operating income	23,183	20,483	21,907	35,225	15,789
Other income (expense)	(26)	66			(25)
Interest expense	9,631	8,650	7,146	6,643	7,943
Income before income taxes	13,526	11,899	14,761	28,582	7,821
Income tax expense	3,814	4,789	5,504	10,469	1,740
Net income	$ 9,712	$ 7,110	$ 9,257	$ 18,113	$ 6,081
Adjusted EBITDA(2)	$ 41,192	$ 35,930	$ 36,748	$ 52,329	$ 28,424

(1) Third-party operation and maintenance expenses do not bear a direct relationship to third-party revenues because all operating expenses ultimately settled with third parties, including utilities, field labor, measurement and analysis and other expenses, are included within third-party operation and maintenance expenses.

(2) We define Adjusted EBITDA as net income (loss), plus interest expense, income taxes and depreciation, less interest income and other income (expense). For a reconciliation of this measure to its directly comparable financial measures calculated and presented in accordance with GAAP, please read Summary historical and pro forma financial and operating data Non-GAAP financial measure.

Table of Contents

Management s discussion and analysis of financial condition and results of operations

OPERATING RESULTS

Our discussion below compares the results for specific periods to the previous comparable period. The discussion compares: (i) the twelve months ended December 31, 2006 to the twelve months ended December 31, 2005, (ii) the twelve months ended December 31, 2005 to the twelve months ended December 31, 2004 and (iii) the nine months ended September 30, 2007 to the nine months ended September 30, 2006.

For purposes of the following discussion:

- Ø any increases or decreases for the year ended December 31, 2006 refer to the comparison of the twelve-month period ended December 31, 2006 to the twelve-month period ended December 31, 2005;
- Ø any increases or decreases for the year ended December 31, 2005 refer to the comparison of the twelve-month period ended December 31, 2005 to the twelve-month period ended December 31, 2004; and
- Ø any increases or decreases for the nine months ended September 30, 2007 refer to the comparison of the nine-month period ended September 30, 2007 to the nine-month period ended September 30, 2006.

We acquired MIGC on August 23, 2006. The following discussion only includes MIGC operating results since the date of its acquisition.

Summary

Total revenues increased by $9.5 million and $3.6 million for the year ended December 31, 2006 and for the year ended December 31, 2005, respectively. Total revenues also increased by $28.0 million for the nine months ended September 30, 2007. The primary reason revenues increased for the year ended December 31, 2006 and for the nine months ended September 30, 2007 was the acquisition of MIGC in August 2006; however, the 2006 and 2007 revenue increases were also aided by increased rates and increased throughput volumes, respectively. The revenue increase for the year ended December 31, 2005 was driven by higher throughput volumes. The revenue increases for these periods were partially offset by higher costs and expenses, as described in more detail below.

Net income increased by $2.6 million and decreased by $2.1 million for the year ended December 31, 2006 and for the year ended December 31, 2005, respectively. Net income increased by $12.0 million for the nine months ended September 30, 2007. The increase in net income for the year ended December 31, 2006 was attributable to the increase in revenue discussed above, partially offset by increased operating costs. The decrease in net income for the year ended December 31, 2005 was attributable to increased operating expenses, partially offset by increased revenues. The increase in net income for the nine months ended September 30, 2007 was attributable to the revenue increase discussed above, partially offset by increased operating costs and income tax expense.

Table of Contents

Management s discussion and analysis of financial condition and results of operations

Revenues and operating statistics

	Year ended December 31,			Nine months ended September 30,	
	2006	**2005**	**2004**	**2007**	**2006**
	(in thousands, except operating and per unit data)				
Revenues					
Affiliate	$ 74,713	$ 66,158	$ 65,340	$ 76,495	$ 52,244
Third-party	6,439	5,492	2,709	9,018	5,237
Total revenues	$ 81,152	$ 71,650	$ 68,049	$ 85,513	$ 57,481
Throughput (MMbtu/d)					
Affiliate	820	757	715	904	778
Third-party	72	41	31	90	64
Total throughput	892	798	746	994	842
Weighted average price per MMbtu					
Affiliate	$ 0.22	$ 0.21	$ 0.21	$ 0.28	$ 0.22
Third-party	$ 0.19	$ 0.16	$ 0.13	$ 0.25	$ 0.21
Total	$ 0.21	$ 0.21	$ 0.21	$ 0.28	$ 0.22

Total revenues. Total revenues increased by $9.5 million and $3.6 million for the year ended December 31, 2006 and for the year ended December 31, 2005, respectively. Total revenues also increased by $28.0 million for the nine months ended September 30, 2007. Additional discussion regarding increases in affiliate and third-party revenues is provided below.

Revenues affiliate. Affiliate revenues increased by $8.6 million for the year ended December 31, 2006. Of this amount, $4.2 million was associated with the acquisition of MIGC. Excluding the operating revenue increases associated with the MIGC acquisition, revenues from affiliates increased by $4.4 million primarily due to increased throughput volumes at PGT. AGC gathering revenues also increased by $0.6 million, as a result of increases in gathering volumes and condensate revenues. Increased gathering volumes at AGC were primarily attributable to continued development of the Haley field.

The $0.8 million increase in affiliate revenues for the year ended December 31, 2005 was largely related to a 15% increase in throughput volumes at AGC, which resulted in a $3.7 million increase in revenues for the period and was partially offset by a $3.0 million decrease in gas imbalance revenues for AGC. The increase in throughput volume at AGC was primarily attributable to increased production activity at the Haley field.

The $24.3 million increase in affiliate revenues for the nine months ended September 30, 2007 included $8.6 million of increased revenues attributable to the inclusion of MIGC operating results for the entire nine-month period ended September 30, 2007 as compared to only 38 days during the nine-month period ended September 30, 2006. The

$15.7 million increase not related to MIGC was mostly attributable to a 6% and 3% increase in throughput volumes, combined with a 19% and 39% increase in average rates realized, at AGC and PGT, respectively. This combination of throughput volume and rate increases resulted in increased gathering revenues of $8.8 million and $5.1 million for AGC and PGT, respectively. The increase in affiliate throughput volumes at AGC was attributable to the continued development of the Haley field. The increase in affiliate throughput volumes at PGT was primarily attributable to the connection of additional wells to the Pinnacle system. In addition, condensate and gas imbalance revenues for AGC increased by $0.9 million and $0.7 million, respectively.

Table of Contents

Management s discussion and analysis of financial condition and results of operations

Revenues third-party. Third-party revenues increased by $0.9 million for the year ended December 31, 2006. Of this amount, $2.3 million was associated with the acquisition of MIGC. Excluding the revenue increases associated with the MIGC acquisition, revenues from third parties decreased by $1.4 million due to a one-time payment on a volume commitment received in 2005.

The $2.8 million increase in third-party revenues for the year ended December 31, 2005 was primarily due to a one-time payment on a volume commitment received in 2005. AGC gathering revenues also increased by $0.7 million due to higher realized rates.

The $3.8 million increase in third-party revenues for the nine months ended September 30, 2007 was primarily attributable to an increase of $4.0 million associated with the inclusion of MIGC operating results for the entire nine-month period ended September 30, 2007 as compared to only 38 days during the nine-month period ended September 30, 2006.

Operating expenses

	Year ended December 31,			Nine months ended September 30,	
	2006	**2005**	**2004**	**2007**	**2006**
	(in thousands)				
Operating expenses					
Affiliate	$ 7,028	$ 8,380	$ 6,676	$ 6,809	$ 6,590
Third-party	32,932	27,340	24,625	26,375	22,467
Depreciation	18,009	15,447	14,841	17,104	12,635
Total operating expenses	$ 57,969	$ 51,167	$ 46,142	$ 50,288	$ 41,692

Total operating expenses. Total operating expenses increased by $6.8 million and $5.0 million for the year ended December 31, 2006 and for the year ended December 31, 2005, respectively. Total operating expenses also increased by $8.6 million for the nine months ended September 30, 2007. Additional discussion regarding changes in affiliate operating expenses, third-party operating expenses and depreciation expense is provided below.

Operating expenses affiliate. Affiliate operating expenses decreased by $1.4 million for the year ended December 31, 2006. This decrease was largely attributable to a $1.7 million decrease in cost of product expenses related to our fuel tracking mechanism. Specifically, for 2006, actual fuel consumed and line loss was exceeded by fuel volumes recovered pursuant to contractual arrangements.

The $1.7 million increase in affiliate operating expenses for the year ended December 31, 2005 was attributable to a $1.1 million increase in cost of product expenses largely attributable to increased replacement cost of gas associated with condensate sales, and a $0.6 million increase in general and administrative expenses related to management fees.

Affiliate operating expenses remained relatively flat for the nine months ended September 30, 2007.

Operating expenses third-party. Third-party operating expenses increased by $5.6 million for the year ended December 31, 2006. The MIGC acquisition resulted in $2.0 million of additional operation and maintenance expenses. Third-party operating expenses, not related to MIGC, increased by $3.6 million, primarily due to increases in operation and maintenance expenses of $1.6 million and $1.0 million for AGC and PGT, respectively, coupled with an $0.8 million increase in property taxes. The AGC increase in operation and maintenance expenses was primarily comprised of surface maintenance and repair and chemical service expense increases at the Helper, Clawson Springs and Dew gathering systems during the period. The increase in operation and maintenance expense at PGT was

Management s discussion and analysis of financial condition and results of operations

primarily comprised of an increase in salary and contract labor expenses and an increase in equipment rental expense for a rental amine unit and a rental compressor unit.

The $2.7 million increase in third-party operating expenses for the year ended December 31, 2005 was largely attributable to a $2.4 million increase in operation and maintenance expenses for AGC primarily due to increased throughput and service level improvements.

Third-party operating expenses increased by $3.9 million for the nine months ended September 30, 2007. Of this amount, $3.1 million was due to higher operation and maintenance and general and administrative expenses and property taxes associated with the inclusion of MIGC operating results for the entire nine-month period ended September 30, 2007 as compared to only 38 days during the nine-month period ended September 30, 2006. Third-party operating expenses not related to MIGC increased by $0.8 million, which was principally attributable to a $1.0 million increase in operation and maintenance expenses, partially offset by a $0.3 million decrease in property taxes.

Operating expenses depreciation. Depreciation expense increased by $2.6 million for the year ended December 31, 2006. This increase included $1.0 million in additional depreciation expense related to the MIGC acquisition. Depreciation expense not related to MIGC increased by $1.6 million due to $1.2 million and $0.4 million increases in deprecation expense related to AGC and PGT, respectively. These increases were primarily attributable to additional capital expenditures related to adding additional compression at the Dew system and additional well connections at PGT.

The $0.6 million increase in depreciation expense for the year ended December 31, 2005 was attributable to a $0.3 million increase in depreciation expense related to each of AGC and PGT. The AGC increase in depreciation expense was primarily due to the expansion at the Haley field. The PGT increase in depreciation expense was primarily due to $4.0 million of capital spent on a project to install a tie-in for connecting the PGT system into a nearby intrastate pipeline.

Depreciation expense increased by $4.5 million for the nine months ended September 30, 2007. Of this amount, $2.2 million was attributable to the inclusion of MIGC operating results for the entire nine-month period ended September 30, 2007 as compared to only 38 days during the nine-month period ended September 30, 2006. The $2.3 million increase in depreciation expense not related to MIGC was due to an increase in AGC s depreciation expense resulting from a $9.3 million increase in capital expenditures related to adding compression and connecting additional wells to the Dew system and continued expansion of the Haley field.

Operating income

	Year ended December 31,			Nine months ended September 30,	
	2006	2005	2004	2007	2006
	(in thousands)				
Operating income excluding MIGC	$ 19,670	$ 20,483	$ 21,907	$ 26,255	$ 15,074

Operating income MIGC	3,513			8,970	715
Operating income reported	$ 23,183	$ 20,483	$ 21,907	$ 35,225	$ 15,789

Reported operating income increased by $2.7 million for the year ended December 31, 2006. This increase included a $3.5 million increase related to the MIGC acquisition. Operating income, excluding operating income related to MIGC, decreased by $0.8 million, primarily due to a $1.6 and $1.0 million increase in AGC and PGT operation and maintenance expense, respectively, and a $1.2 million increase in AGC depreciation expense, partially offset by a $2.3 million and $0.7 million increase in PGT and AGC revenues, respectively.

Table of Contents

Management s discussion and analysis of financial condition and results of operations

Operating income decreased by $1.4 million for the year ended December 31, 2005. This decrease was primarily due to a $2.4 million increase in AGC operation and maintenance expense, a $1.1 million increase in cost of product expenses, and $0.6 million and $0.6 million increases in general and administrative expense and depreciation, respectively, partially offset by a $2.1 million and $1.5 million increase in AGC and PGT revenues, respectively.

Operating income increased by $19.4 million for the nine months ended September 30, 2007. This increase included an increase of $8.3 million due to the inclusion of MIGC operating results for the entire nine-month period ended September 30, 2007 as compared to only 38 days during the nine-month period ended September 30, 2006. Excluding the effect of MIGC operating results, operating income increased by $11.1 million due to a $8.1 million and $3.0 million increase in operating income at AGC and PGT, respectively. The $8.1 million increase in AGC s operating income included an increase of $10.0 million in revenues, and a $0.8 million decrease in operation and maintenance expenses, partially offset by a $2.0 million increase in depreciation expense. The $3.0 million increase in PGT s operating income was principally attributable to increased throughput volumes and realized gathering rates, which resulted in a $5.4 million increase in revenues, partially offset by a $2.0 million increase in operation and maintenance expenses for the period.

Income tax expense

	Year ended December 31,			Nine months ended September 30	
	2006	2005	2004	2007	2006
	(in thousands, except tax rates)				
Income before income taxes	$ 13,526	$ 11,899	$ 14,761	$ 28,582	$ 7,821
Income tax expense	3,814	4,789	5,504	10,469	1,740
Effective tax rate	28.20%	40.25%	37.29%	36.63%	22.25%

The decrease in the effective tax rate for the year ended December 31, 2006 was primarily due to the recording of a one-time benefit to deferred state income tax for the new Texas margin tax enacted in May 2006. The increase in the effective tax rate for the year ended December 31, 2005 was primarily due to additional state income taxes attributable to an increase in apportioned income to states with higher statutory tax rates. The increase in the effective rate for the nine months ended September 30, 2007 was primarily due to a one-time benefit to deferred state income tax for the new Texas margin tax recorded in the prior period.

The net decrease in income taxes for the year ended December 31, 2006 was primarily due to the recording of a one-time benefit to deferred state income tax for the new Texas margin tax enacted in May 2006, partially offset by the tax impact of the increase in income before income taxes. The net decrease in income taxes for the year ended December 31, 2005 was primarily due to a decrease in income before income taxes, partially offset by additional state income taxes attributable to an increase in apportioned income to states with higher statutory rates. The net increase in income taxes for the nine months ended September 30, 2007 was primarily due to a one-time benefit to deferred state income tax for the new Texas margin tax recorded in the prior period and higher income before income taxes in the nine months ended September 30, 2007.

Texas House Bill 3, signed into law in May 2006, eliminated the taxable capital and earned surplus components of the existing franchise tax and replaced these components with a taxable margin tax calculated on a combined group reporting basis. Our Predecessor was required to include the impact of the new law in income for the period which included the date of the law s enactment. The adjustment, a

86

Management s discussion and analysis of financial condition and results of operations

reduction in deferred state income taxes in the amount of approximately $1.1 million, net of federal tax benefit, was included in 2006 income tax expense.

LIQUIDITY AND CAPITAL RESOURCES

Our ability to finance operations and fund maintenance capital expenditures will largely depend on our ability to generate sufficient cash flow to cover these expenses. Our ability to generate cash flow is subject to a number of factors, some of which are beyond our control. Please read Risk factors included elsewhere in this prospectus.

Historically, our sources of liquidity included cash generated from operations and funding from Anadarko. We historically participated in Anadarko s cash management program, whereby Anadarko, on a periodic basis, swept cash balances residing in our bank accounts. Thus, our historical combined financial statements reflect little or no cash balances. Unlike our transactions with third parties which ultimately settle in cash, our affiliate transactions are settled on a net basis through an adjustment to parent net equity.

Prospectively, we will maintain our own bank accounts and sources of liquidity and will utilize Anadarko s cash management system and expertise.

Subsequent to this offering, we expect our sources of liquidity to include:

Ø $10 million of net offering proceeds to be retained for general partnership purposes;

Ø cash generated from operations;

Ø borrowings under Anadarko s credit facility up to the amount of our borrowing limit;

Ø borrowings under our working capital facility with Anadarko;

Ø interest income from our $337.6 million note receivable from Anadarko;

Ø issuances of additional partnership units; and

Ø 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.

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 by changes in accounts receivable and accounts payable. These changes are primarily impacted 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. Historically, all affiliated transactions were not cash settled within our combined financial statements, and did not require independent working capital borrowings. Prospectively, to the extent transactions with Anadarko and third parties require working capital, such amounts will be independently obtained by us.

Historical combined cash flow

The following table and discussion presents a summary of our combined net cash provided by (used in) operating activities, combined net cash provided by (used in) investing activities and combined net cash provided by (used in) financing activities for the years ended December 31, 2006, 2005 and 2004 and for the nine months ended September 30, 2007 and 2006.

Management s discussion and analysis of financial condition and results of operations

For all periods presented below, our net cash from operating activities and capital contributions from our parent were used to service our cash requirements, which included our operating expenses, maintenance capital expenditures and expansion capital expenditures.

	Year ended December 31, 2006	2005	2004	Nine months ended September 30, 2007	2006
	(in thousands)				
Net cash provided by (used in):					
Operating activities	$ 27,323	$ 30,131	$ 31,160	$ 41,810	$ 12,941
Investing activities	$ (42,713)	$ (21,076)	$ (16,548)	$ (37,247)	$ (27,952)
Financing activities	$ 15,844	$ (9,067)	$ (14,596)	$ (5,021)	$ 15,007
Net increase (decrease) in cash	$ 454	$ (12)	$ 16	$ (458)	$ (4)

Operating Activities. Net cash provided by operating activities decreased by $2.8 million, or 9%, for the year ended December 31, 2006. Net cash provided by operating activities decreased by $1.0 million, or 3%, for the year ended December 31, 2005. Net cash provided by operating activities increased by $28.9 million, or 223%, for the nine months ended September 30, 2007.

The $2.8 million decrease in net cash provided by operating activities during the year ended December 31, 2006 was primarily due to a $6.9 million decrease in net accounts payable and accrued expenses, natural gas imbalances, and accounts receivable, offset by $4.4 million of additional net cash provided by operating activities related to MIGC.

The $1.0 million decrease in net cash provided by operating activities during the year ended December 31, 2005 was primarily due to a $2.2 million decrease in net income, partially offset by a $1.2 million increase in net cash provided from changes in assets and liabilities.

The $28.9 million increase in net cash provided by operating activities during the nine months ended September 30, 2007 was primarily due to a $10.4 million increase in net cash provided by operating activities related to MIGC, a $13.4 million increase in net income, not related to MIGC, adjusted for non-cash items and a $6.6 million increase from changes in accounts payable and accrued expenses.

Investing Activities. Net cash used in investing activities for the year ended December 31, 2006 increased by $21.6 million, or 103%. Net cash used in investing activities increased by $4.5 million, or 27%, for the year ended December 31, 2005. Net cash used in investing activities increased by $9.3 million, or 33%, for the nine months ended September 30, 2007.

Our investing activities included $21.5 million, $4.5 million, and $9.3 million in capital expenditure increases for the year ended December 31, 2006, the year ended December 31, 2005, and the nine months ended September 30, 2007, respectively.

The increase in capital expenditures for the year ended December 31, 2006 was related to additional compression and well connections on the Dew system and additional well connections on the Haley system.

The increase in capital expenditures for the year ended December 31, 2005 was attributable to increased activity within the Haley field and the Dew gathering system.

The increase in capital expenditures for the nine months ended September 30, 2007 was attributable to adding compression and connecting additional wells to the Dew system.

Financing Activities. Net cash provided by financing activities for the year ended December 31, 2006 increased by $24.9 million. Net cash used in financing activities decreased by $5.5 million for the year

Management s discussion and analysis of financial condition and results of operations

ended December 31, 2005. Net cash provided by financing activities decreased by $20.0 million for the nine months ended September 30, 2007. All increases and decreases were attributable to period-to-period variances in cash contributions from or cash payments to Anadarko.

Off-balance sheet arrangements

We do not have any off-balance sheet arrangements.

Capital requirements

Our businesses can be capital-intensive, requiring significant investment to maintain and improve existing facilities. We categorize capital expenditures as either:

- Maintenance capital expenditures, which include those expenditures required to maintain the existing operating capacity and service capability of our assets, including the replacement of system components and equipment that have suffered significant wear and tear, become obsolete or approached the end of their useful lives, those expenditures necessary to remain in compliance with regulatory or legal requirements or those expenditures necessary to complete additional well connections to maintain existing system volumes and related cash flows; or

- Expansion capital expenditures, which include those expenditures incurred in order to extend the useful lives of our assets, increase gathering, treating and transmission throughput from current levels, reduce costs or increase revenues.

Our historical accounting records did not differentiate between maintenance and expansion capital expenditures. We estimate that expansion capital expenditures represented approximately 63%, 49% and 35% of total capital expenditures for the years ended December 31, 2006, 2005 and 2004, respectively. Our total historical capital expenditures were as follows:

	Year ended December 31,			Nine months ended September 30,	
	2006	2005	2004	2007	2006
	(in thousands)				
Total capital expenditures, net	$ 42,299	$ 20,841	$ 16,548	$ 37,020	$ 27,709

We expect our maintenance and expansion capital expenditures for the twelve months ending December 31, 2008 to be $28.0 million and $15.9 million, respectively. Two components of our strategy are growth through organic expansion and pursuit of accretive acquisitions, and we expect to invest capital in a manner that positions us to execute on our strategy. Our future expansion capital expenditures may vary significantly from period to period based on the investment opportunities available to us. We expect to fund future capital expenditures from cash flow generated from our operations, borrowings under Anadarko s credit facility, the issuance of additional partnership units and debt offerings.

Our borrowing capacity under Anadarko s credit facility

On December 14, 2007, Anadarko amended its $750 million credit facility, which is available for borrowings and letters of credit, to permit us to borrow up to $100 million under the facility. Anadarko s credit facility has a maturity date of August 31, 2009. Our $100 million borrowing limit under Anadarko s credit facility is available for general partnership purposes, including acquisitions, but only to the extent that sufficient amounts remain unborrowed by Anadarko and its other subsidiaries. At September 30, 2007, letters of credit totaling $3.0 million had been issued on behalf of Anadarko by the participating institutions under this facility and no revolving credit loans were outstanding.

Management s discussion and analysis of financial condition and results of operations

Interest on borrowings under this credit facility is calculated based on the election by the borrower of either: (i) a floating rate equal to the federal funds effective rate plus 0.5% or (ii) a periodic fixed rate equal to LIBOR plus an applicable margin. We are required to pay a commitment fee based on the unused portion of our $100 million borrowing capacity under the facility, currently 0.175% annually. The applicable margin, which is currently 0.675%, and the commitment fees are based on Anadarko s senior unsecured long-term debt rating. Under the credit facility, Anadarko and we are required to comply with certain covenants, including a financial covenant that requires both Anadarko and us to maintain a debt-to-book capitalization ratio of 60% or less. Anadarko was in compliance with this ratio at September 30, 2007. Should we or Anadarko fail to comply with this or any other covenant in Anadarko s credit facility, we may not be allowed to borrow under Anadarko s credit facility. Pursuant to the credit facility, Anadarko is a guarantor of all borrowings under the credit facility, including our borrowings. We are not a guarantor of Anadarko s borrowings under the credit facility.

Our working capital facility

Concurrently with the closing of this offering, we will enter into a $30 million, two-year, revolving credit facility with Anadarko as the lender. The facility will be available exclusively to fund working capital borrowings. Borrowings under the facility will bear interest at the same rate as would apply to borrowings under the Anadarko revolving credit facility described above. We will pay a commitment fee to Anadarko on the unused portion of the working capital facility of 0.175% annually.

We will be required to reduce all borrowings under our working capital facility to zero for a period of at least 15 consecutive days at least once during each of the twelve-month periods prior to the maturity date of the facility.

Credit risk

We bear credit risk represented by our exposure to non-payment or non-performance by our customers, including Anadarko. Generally, non-payment or non-performance results from a customer s inability to satisfy receivables for services rendered or volumes owed pursuant to gas imbalance agreements. We examine the creditworthiness of third-party customers to whom we grant credit and establish credit limits in accordance with our credit policy. We are dependent upon a single producer, Anadarko, for the majority of our natural gas volumes, and we do not have a credit policy with respect to Anadarko. Consequently, we are subject to the risk of non-payment or late payment by Anadarko of gathering, treating and transmission fees, and this risk is greater than it would be with a broader customer base with a similar credit profile. We expect our exposure to concentrated risk of non-payment or non-performance to continue for as long as we remain substantially dependent on Anadarko for our revenues.

While Anadarko currently has investment grade credit ratings, if Anadarko becomes unable to perform under the terms of our gathering and transportation agreements, its note payable to us or the omnibus agreement, it may significantly reduce our ability to make distributions to our unitholders. We will be exposed to credit risk on the note receivable from Anadarko that will be issued by Anadarko to us concurrently with the closing of this offering. In addition, we will enter into an omnibus agreement with Anadarko under which Anadarko is required to indemnify us for certain environmental claims, losses arising from rights-of-way claims, failures to obtain required consents or governmental permits, and income taxes.

Management s discussion and analysis of financial condition and results of operations

Total contractual cash obligations

A summary of our total contractual cash obligations as of December 31, 2006, which consisted of four compressor leases, is as follows:

	Total	Less than 1 year	2-3 years	4-5 years	More than 5 years
			(in thousands)		
Lease commitments	$ 13,359	$ 3,123	$ 4,177	$ 4,277	$ 1,782

During the nine months ended September 30, 2007, Anadarko exercised its option to purchase three of the four compressors which were under lease from a third party to Anadarko and subleased by Anadarko to us. Anadarko then transferred the compressors to us as a contribution to our capital. This transaction is expected to reduce operation and maintenance expense by approximately $1.7 million annually, which will be partially offset by a $1.5 million increase in depreciation expense. As a result of this transaction, our contractual cash obligations changed, and at September 30, 2007 were as follows:

	Total	Less than 1 year	2-3 years	4-5 years	More than 5 years
			(in thousands)		
Lease commitments	$ 5,360	$ 799	$ 1,936	$ 1,958	$ 667

In addition to the obligations listed above, we will enter into an omnibus agreement with Anadarko whereby we will reimburse Anadarko for certain operating and general and administrative expenses it incurs for our benefit with respect to our assets and operations. Under the omnibus agreement, our reimbursement to Anadarko for certain general and administrative expenses it allocates to us will be capped at $6.0 million annually through December 31, 2009, subject to adjustment to reflect changes in the Consumer Price Index and, with the concurrence of the special committee of our general partner s board of directors, to reflect expansions of our operations through the acquisition or construction of new assets or businesses. Thereafter, our general partner will determine the general and administrative expenses to be reimbursed by us in accordance with our partnership agreement. The cap contained in the omnibus agreement does not apply to incremental general and administrative expenses we expect to incur or to be allocated to us as a result of becoming a publicly traded partnership. We currently expect those expenses to be approximately $2.5 million per year.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity price risk

We bear a limited degree of commodity price risk with respect to our gathering contracts. Specifically, pursuant to our contracts, we retain and sell condensate that is recovered during the gathering of natural gas. As part of this arrangement, we are required to provide a thermally equivalent volume of natural gas or the cash equivalent thereof to the shipper. Thus, our revenues for this portion of our contractual arrangement are based on the price received for the condensate and our costs for this portion of our contractual arrangement are dependent upon the price of natural gas. Condensate historically sells at a price representing a slight discount to the price of crude oil. We consider our exposure to commodity price risk associated with these arrangements to be minimal based on the amount of operating income generated under these arrangements compared to our overall operating income and the fact that the balance of our operating income is fee-based. For the years ended December 31, 2006, 2005 and 2004, a 10% change in the trading margin between condensate and natural gas would have resulted in a $375,000, or 1.6%, $250,000, or 1.2%, and $206,000, or 1.0%, change in operating income for those periods, respectively.

Management s discussion and analysis of financial condition and results of operations

Interest rate risk

Interest rates during the periods discussed above were low compared to rates over the last 50 years. If interest rates were to rise, our financing costs would increase accordingly. Although increased borrowing costs could limit our ability to raise funds in the capital markets, we expect our competitors would be similarly affected. We expect to have immaterial amounts of borrowings through December 31, 2008. Accordingly, we do not expect to have any material interest rate risk.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of combined financial statements in accordance with accounting principles generally accepted in the U.S. requires our management to make estimates and assumptions that affect the amounts reported in the combined financial statements and the accompanying notes. Although these estimates are based on management s best available knowledge of current and expected future events, actual results may vary significantly from those estimates. Management considers an understanding of our critical accounting policies and estimates to be essential to gaining a full understanding of our combined financial results. For additional information concerning our accounting policies not discussed below, see the Notes to the Combined Financial Statements included elsewhere in this prospectus.

Depreciation and impairment policy

Depreciation expense is generally computed using the straight-line method over the estimated useful life of the assets. Determination of depreciation expense requires judgment regarding the estimated useful lives and salvage values of property, plant and equipment. As circumstances warrant, depreciation estimates are reviewed to determine if any changes in the underlying assumptions are necessary.

Each reporting period, management assesses whether facts and circumstances indicate that the carrying amounts of property, plant and equipment may not be recoverable from expected undiscounted cash flows from the use and eventual disposition of an asset. If the carrying amount of the asset is not expected to be recoverable from future undiscounted cash flows, an impairment may be recognized. Any impairment is measured as the excess of the carrying amount of the asset over its estimated fair value. The weighted average life of our long-lived assets is approximately 21 years. If the depreciable lives of our assets were reduced by 10%, we estimate that depreciation expense would increase by $2.5 million, which would result in a corresponding reduction in our operating income.

In assessing long-lived assets for impairment, management evaluates changes in our business and economic conditions and their implications for recoverability of the assets carrying amounts. Since a significant portion of our revenues arises from gathering and transporting natural gas production from Anadarko-operated properties, significant downward revisions in reserve estimates or changes in future development plans by Anadarko, to the extent they affect our operations, may necessitate assessment of the carrying amount of our affected assets for recoverability. Such assessment requires application of judgment regarding the use and ultimate disposition of the asset, long-range revenue and expense estimates, global and regional economic conditions, including commodity prices and drilling activity by our customers, as well as other factors affecting estimated future net cash flows. The measure of impairment to be recognized, if any, depends upon management s estimate of the asset s fair value, which may be determined based on the estimates of future net cash flows or values at which similar assets were transferred in the market in recent transactions, if such data is available. For the periods presented, we believe that no facts were present that would indicate the carrying amount of assets may not be recoverable. However, given the degree of judgment about highly uncertain matters involved in assessing our key assets for impairment, it is reasonably possible that such assessments in future periods would have material effects on our financial conditions and results of operations. If an assessment of impairment resulted in a reduction of 1% of our assets, our operating income would decrease by $3.5 million.

Table of Contents

Business

OVERVIEW

We are a growth-oriented Delaware limited partnership recently formed by Anadarko (NYSE: APC) to own, operate, acquire and develop midstream energy assets. We currently operate in East Texas, the Rocky Mountains, the Mid-Continent and West Texas and are engaged in the business of gathering, compressing, treating and transporting natural gas for our ultimate parent, Anadarko, and third-party producers and customers. We principally provide our midstream services under long-term contracts with fee-based rates extending for primary terms of up to 20 years. We generally do not take title to the natural gas that we gather and, therefore, are able to avoid significant direct commodity price exposure.

We believe that one of our principal strengths is our relationship with Anadarko. During each of the year ended December 31, 2006 and the nine months ended September 30, 2007, over 90% of our total natural gas gathering and transportation volumes were comprised of natural gas production owned or controlled by Anadarko. In addition, Anadarko Petroleum Corporation has dedicated to us all of the natural gas production it owns or controls from (i) wells that are currently connected to our gathering systems, and (ii) additional wells that are drilled within one mile of connected wells or our gathering systems, as the systems currently exist and as they are expanded to connect additional wells in the future. As a result, this dedication will continue to expand as additional wells are connected to our gathering systems. Volumes associated with this dedication were approximately 736 MMBtu/d for the year ended December 31, 2006 and approximately 738 MMBtu/d for the nine months ended September 30, 2007.

We expect to utilize the significant experience of Anadarko s management team to execute our growth strategy, which includes acquiring and constructing additional midstream assets. For the nine months ended September 30, 2007, as adjusted for divestitures prior to this offering and including the assets being contributed to us, Anadarko s total domestic midstream asset portfolio consisted of 25 gathering systems and one transportation system with an aggregate throughput of approximately 3.0 Bcf/d, approximately 11,200 miles of pipeline and 25 processing and/or treating facilities.

OUR ASSETS AND AREAS OF OPERATION

Our assets consist of six gathering systems, five natural gas treating facilities and one interstate pipeline. Our assets are located in East Texas, the Rocky Mountains (Utah and Wyoming), the Mid-Continent (Kansas and Oklahoma) and West Texas. The following table provides information regarding our assets by operating area as of or for the nine months ended September 30, 2007:

Area	Asset type	Length (miles)	Approximate # of receipt points	Gas compression (horsepower)	Treating capacity (MMcf/d)	Average throughput (MMcf/d)
East Texas	Gathering and Treating	577	789	45,633	510	304(1)
Rocky Mountains	Gathering and Treating	114	162	20,385	92	55
	Transportation	264	19	29,696		137
Mid-Continent	Gathering	1,753	1,507	130,720		123

West Texas	Gathering	87	50			185
Total		2,795	2,527	226,434	602	804

(1) To avoid duplicating volumes, 213 MMcf/d that is gathered on our Dew gathering system and delivered into our Pinnacle gas treating system is included only once in the calculation of average throughput.

Table of Contents

Business

STRATEGY

Our primary business objective is to increase our cash distribution per unit over time. We intend to accomplish this objective by executing the following strategy:

Ø *Pursuing accretive acquisitions.* We expect to pursue accretive acquisition opportunities within the midstream energy industry from Anadarko and third parties. Given Anadarko s large portfolio of midstream assets, we believe that we will have access to an array of acquisition opportunities, though Anadarko is under no legal obligation to offer assets or business opportunities to us. In addition, we may also pursue selected asset acquisitions from third parties to the extent such acquisitions complement our or Anadarko s existing asset base or allow us to capture operational efficiencies from Anadarko s production.

Ø *Capitalizing on organic growth opportunities.* The significant dedication to us by Anadarko provides us with a platform for organic growth. We expect to achieve this growth by meeting Anadarko s gathering needs, which we expect to increase as a result of its anticipated drilling activity in our areas of operation. We also intend to actively pursue new volumes associated with Anadarko s development of undeveloped acreage that is accessible by our gathering systems. Examples of organic growth opportunities potentially arising from our relationship with Anadarko include:

- Anadarko s active drilling program in the East Texas Bossier play, including the Cotton Valley Lime formations; and

- Anadarko s increased drilling and recompletion activity in the Hugoton field as a result of recent rule changes by the Kansas Corporation Commission.

Ø *Attracting additional third-party volumes to our systems.* We intend to actively market our midstream services to and pursue strategic relationships with third-party producers to attract additional volumes and/or expansion opportunities. Recent examples of such expansions include:

- the planned expansion of the sour gas treating capacity of our Bethel plant to accommodate the recent drilling activity by third parties in the Cotton Valley Lime formations; and

- the expansion of the Hugoton gathering system to obtain volumes previously gathered by a competitor s system.

Ø *Minimizing commodity price exposure.* Our midstream services are provided under fee-based arrangements which minimize our direct commodity price exposure. We expect to utilize hedging to manage any significant future commodity price risk that could result from contracts we may acquire or enter into in the future.

COMPETITIVE STRENGTHS

We believe that we are well positioned to successfully execute our strategy and achieve our primary business objective because of the following competitive strengths:

Ø

Affiliation with Anadarko. We believe that Anadarko, as the owner of our general partner interest, all of our incentive distribution rights and a 57.3% limited partner interest in us, is motivated to promote and support the successful execution of our business plan and to pursue projects that enhance the value of our business. We believe that our relationship with Anadarko will enhance our ability to achieve our primary business objective through, for example, the following:

- Anadarko Petroleum Corporation has dedicated to us all of the natural gas production it owns or controls from (i) wells that are currently connected to gathering systems, and (ii) additional wells that are drilled within one mile of connected wells or our gathering systems, as the systems currently exist and as they are expanded to connect additional wells in the future;

94

Table of Contents

Business

- as Anadarko develops the acreage in proximity to our gathering systems or acquires additional acreage in our areas of operation, we believe that it will deliver additional volumes to our facilities, although it is not obligated to do so;
- Anadarko manages a large portfolio of midstream assets in highly active oil and natural gas producing areas, such as the Rocky Mountains, and we believe that Anadarko may offer us the opportunity to purchase some or all of such assets in the future, although it is not obligated to do so; and
- we have access to Anadarko s broad operational, commercial, technical, risk management and administrative infrastructure, its significant pool of management talent and its strong commercial relationships throughout the energy industry.

Ø *Relatively stable and predictable cash flow.* Given the fee-based, long-term nature of our midstream service agreements, our cash flow is largely protected from fluctuations caused by commodity price volatility. In addition, our contracts have primary terms ranging up to 20 years, and we generally do not take title to the natural gas that we gather, compress, treat or transport. Moreover, our systems are connected to wells in producing basins that generally have long lives with predictable flow rates.

Ø *Well-positioned, well-maintained and efficient assets.* We believe that our established positions in our areas of operation provide us with opportunities to expand and attract additional volumes to our systems. Moreover, our systems consist of high-quality, well-maintained assets for which we have implemented modern treating, measuring and operating technologies. These applications have allowed us to manage our operations efficiently with limited field personnel, resulting in lower costs and minimal downtime.

Ø *Financial flexibility to pursue expansion and acquisition opportunities.* We have up to $100 million of borrowing capacity available to us under Anadarko s $750 million credit facility and, concurrently with the closing of this offering, we expect to obtain a $30 million working capital facility from Anadarko. In addition, we will have no indebtedness outstanding at the closing of this offering. We believe that our borrowing capacity and our ability to effectively access debt and equity capital markets provide us with the financial flexibility necessary to achieve our organic expansion and acquisition strategy.

Ø *Experienced management team.* Our general partner s management team, which includes senior executives of Anadarko, has on average over 15 years of industry experience. Members of our general partner s management team have extensive experience in building, acquiring, integrating, financing and managing midstream assets. In addition, our relationship with Anadarko provides us with the services of experienced personnel who successfully managed our assets and operations while they were owned by Anadarko.

We believe that we will effectively leverage our competitive strengths to successfully implement our strategy; however, our business involves numerous risks and uncertainties which may prevent us from achieving our primary business objective. For a more complete description of the risks associated with an investment in us, please read Risk factors.

OUR RELATIONSHIP WITH ANADARKO

One of our principal attributes is our relationship with Anadarko. It will own our general partner and a significant interest in us following this offering. Anadarko is one of the largest independent oil and gas exploration and production companies in the world. Anadarko, which trades on the NYSE under the symbol APC, has major operations in established onshore areas of the U.S., including the Rocky Mountains, as well as in the deepwater Gulf of Mexico and Algeria. Anadarko also has production in China, a development project in Brazil and is executing strategic exploration programs in several other countries.

Table of Contents

Business

Anadarko s upstream oil and gas business finds and produces natural gas, crude oil, condensate and NGLs. Anadarko is growth-oriented and annually pursues one of the most active drilling programs in the industry, with over 1,400 development wells drilled onshore in the U.S. in 2006. Anadarko has identified the Rocky Mountains and its Southern region (which includes the Mid-Continent and Texas) as core areas from which it expects to derive a significant portion of its future production growth from development drilling activity. We expect Anadarko to remain active in our areas of operation, which we believe will provide us with both organic and acquisition-related growth opportunities.

At September 30, 2007, including the assets being contributed to us but adjusted for divestitures prior to this offering, Anadarko s total domestic midstream asset portfolio consisted of 25 gathering systems and one transportation system with an aggregate throughput of approximately 3.0 Bcf/d, approximately 11,200 miles of pipeline and 25 processing and/or treating facilities. Following this offering, Anadarko s remaining midstream business will consist of 19 gathering systems with an aggregate throughput of approximately 2.2 Bcf/d, 8,400 miles of pipeline and 20 processing and/or treating facilities. Anadarko has invested significant capital in its domestic midstream business, including the assets being contributed to us, with investments of approximately $290 million in 2006 and planned investments of approximately $600 million in 2007, of which approximately $475 million had been invested as of September 30, 2007. On December 27, 2007, Anadarko announced a $2.2 billion financing of its midstream assets which may require partial repayment based on a debt to EBITDA leverage ratio that declines incrementally over time. The debt repayments that may be necessary to satisfy the terms of this financing may be made with internally generated cash flow, cash on hand, or cash received from midstream asset sales. Should Anadarko choose to pursue midstream asset sales, it is under no contractual obligation to offer assets or business opportunities to us. We are neither a guarantor nor an obligor for such financing.

Although our relationship with Anadarko provides us with a significant advantage in the midstream natural gas market, it is also a source of potential conflicts. For example, Anadarko is not restricted from competing with us. Please read Conflicts of interest and fiduciary duties. Given Anadarko s significant ownership of limited and general partner interests in us following this offering, we believe it will be in Anadarko s best interest for it to sell additional assets to us over time; however, Anadarko continually evaluates acquisitions and divestitures and may elect to acquire, construct or dispose of midstream assets in the future without offering us the opportunity to acquire or construct those assets. Anadarko is under no contractual obligation to offer any such opportunities to us, nor are we obligated to participate in any such opportunities. We cannot state with any certainty which, if any, opportunities to acquire assets from Anadarko may be made available to us or, if given the opportunity, that we will elect to pursue any such acquisitions.

At the close of this offering, we will enter into an omnibus agreement with Anadarko and our general partner that will govern our relationship regarding certain reimbursement and indemnification matters. Please read Certain relationships and related party transactions Agreements governing the transactions Omnibus agreement.

Table of Contents

Business

INDUSTRY OVERVIEW

The midstream natural gas industry is the link between the exploration and production of natural gas from the wellhead or lease and the delivery of the gas and its other components to end-use markets. Companies within this industry create value at various stages along the natural gas value chain by gathering natural gas from producers at the wellhead, separating the hydrocarbons into dry gas (primarily methane) and NGLs, and then routing the separated dry gas and NGL streams for delivery to end-markets or to the next intermediate stage of the value chain. The following diagram illustrates the groups of assets commonly found along the natural gas value chain:

Service types

The services provided by us and other midstream natural gas companies are generally classified into the categories described below. As indicated below, we do not currently provide all of these services, although we may do so in the future.

Gathering. At the initial stages of the midstream value chain, a network of typically small diameter pipelines known as gathering systems directly connect to wellheads in the production area. These gathering systems transport raw, or untreated, natural gas to a central location for treating and processing. A large gathering system may involve thousands of miles of gathering lines connected to thousands of wells. Gathering systems are typically designed to be highly flexible to allow gathering of natural gas at different pressures and scalable to allow gathering of additional production without significant incremental capital expenditures. In connection with our gathering services, we retain and sell condensate, which falls out of the natural gas stream during gathering.

Compression. Natural gas compression is a mechanical process in which a volume of natural gas at a given pressure is compressed to a desired higher pressure, which allows the natural gas to be delivered into a higher pressure system. Field compression is typically used to allow a gathering system to operate at a lower pressure or provide sufficient discharge pressure to deliver natural gas into a higher pressure system. Since wells produce at progressively lower field pressures as they deplete, field compression is needed to maintain throughput across the gathering system.

Treating and Dehydration. To the extent that gathered natural gas contains contaminants, such as water vapor, carbon dioxide and/or hydrogen sulfide, such natural gas is dehydrated to remove the saturated water and treated to separate the carbon dioxide and hydrogen sulfide from the gas stream.

Processing. Most decontaminated rich natural gas does not meet the quality standards for long-haul pipeline transportation or commercial use and must be processed to remove the heavier hydrocarbon components, which are extracted as NGLs. Our assets do not currently include processing facilities.

Table of Contents

Business

Fractionation. Fractionation is the separation of the heterogeneous mixture of extracted NGLs into individual components for end-use sale. It is accomplished by controlling the temperature and pressure of the stream of mixed NGLs in order to take advantage of the different boiling points of separate products. Our assets do not currently include fractionation operations.

Transportation and Storage. Once the raw natural gas has been treated or processed and the raw NGL mix fractionated into individual NGL components, the natural gas and NGL components are stored, transported and marketed to end-use markets. Each pipeline system typically has storage capacity located both throughout the pipeline network and at major market centers to help temper seasonal demand and daily supply-demand shifts. Our assets do not currently include storage facilities.

Typical Contractual Arrangements. Midstream natural gas services, other than transportation and storage, are usually provided under contractual arrangements which vary in the amount of commodity price risk they carry. Three typical contract types are described below:

- *Fee-Based.* Fee-based arrangements may be used for gathering, compression, treating and processing services. Under these arrangements, the service provider typically receives a fee for each unit of natural gas gathered and compressed at the wellhead and an additional fee per unit of natural gas treated or processed at its facility. As a result, the service provider bears no direct commodity price risk exposure. We provide our gathering, compression and treating services to Anadarko and third-party producers under fee-based arrangements which minimize our direct commodity price exposure.

- *Percent-of-Proceeds, Percent-of-Value or Percent-of-Liquids.* Percent-of-proceeds, percent-of-value or percent-of-liquids arrangements may be used for gathering and processing services. Under these arrangements, the service provider typically remits to the producers either a percentage of the proceeds from the sale of residue gas and/or NGLs or a percentage of the actual residue gas and/or NGLs at the tailgate. These types of arrangements expose the processor to commodity price risk, as the revenues from the contracts directly correlate with the fluctuating price of natural gas and NGLs. We do not currently have any percent-of-proceeds, percent-of-value or percent-of-liquids arrangements.

- *Keep-Whole.* Keep-whole arrangements may be used for processing services. Under these arrangements, the service provider keeps 100% of the NGLs produced, and the processed natural gas, or value of the gas, is returned to the producer. Since some of the gas is used and removed during processing, the processor compensates the producer for the amount of gas used and removed in processing by supplying additional gas or by paying an agreed-upon value for the gas utilized. These arrangements have the highest commodity price exposure for the processor because the costs are dependent on the price of natural gas and the revenues are based on the price of NGLs. We do not currently have any keep-whole arrangements.

There are two forms of contracts utilized in the transportation and storage of natural gas, as described below:

- *Firm.* Firm transportation service requires the reservation of pipeline capacity by a customer between certain receipt and delivery points. Firm customers generally pay a demand or capacity reservation fee based on the amount of capacity being reserved, regardless of whether the capacity is used, plus a usage fee based on the amount of natural gas transported. Firm storage contracts involve the reservation of a specific amount of storage capacity, including injection and withdrawal rights, and generally include a capacity reservation charge based on the amount of capacity being reserved plus an injection and/or withdrawal fee.

- Ø *Interruptible.* Interruptible transportation and storage service is typically short-term in nature and is generally used by customers that either do not need firm service or have been unable to contract for firm service. These customers pay only for the volume of gas actually transported or stored. The obligation to provide this service is limited to available capacity not otherwise used by firm

98

Business

customers, and as such, customers receiving services under interruptible contracts are not assured capacity on the pipeline or at the storage facility.

Natural gas demand and production

Natural gas is a critical component of energy supply in the U.S. According to the Energy Information Administration, or the EIA, total annual domestic consumption of natural gas is expected to increase from approximately 21.7 trillion cubic feet, or Tcf, in 2006 to approximately 24.7 Tcf in 2010. The industrial and electricity generation sectors are the largest consumers of natural gas in the U.S. During the last three years, these sectors accounted for approximately 57% of the total natural gas consumed in the U.S. In 2006, natural gas provided approximately 22% of all end-user commercial and residential energy requirements. During the last three years, the U.S. has, on average, consumed approximately 22.0 Tcf per year, with average annual domestic production of approximately 18.4 Tcf during the same period. Driven by growth in natural gas demand and high natural gas prices, domestic natural gas production is projected to increase from 18.6 Tcf per year to 19.6 Tcf per year between 2006 and 2016. The graph below represents projected U.S. natural gas production versus U.S. natural gas consumption (in Tcf) through the year 2030.

Source: Energy Information Administration

OUR ASSETS

We own and operate all of our assets, which consist of six gathering systems, five natural gas treating facilities and one interstate pipeline, in East Texas, the Rocky Mountains (Utah and Wyoming), the Mid-Continent (Kansas and Oklahoma) and West Texas. Other than the natural gas that is gathered by our Hugoton gathering system, which is currently processed by third parties, none of the natural gas serviced by our assets requires processing. The following sections describe in more detail the services provided by our assets in our areas of operation.

East Texas

Dew gathering system

General. The 317-mile Dew gathering system is located in Anderson, Freestone, Leon and Robertson Counties of East Texas. The Dew gathering system was placed into service in November 1998 to provide gathering services for Anadarko s active drilling program in the Bossier play. The system provides gathering, dehydration and compression services and ultimately delivers into the Pinnacle gas treating system for any required treating.

Business

Average throughput on the Dew gathering system for the year ended December 31, 2006 and the nine months ended September 30, 2007 was 235 MMcf/d and 217 MMcf/d, respectively, from approximately 725 receipt points. The Dew gathering system has pipeline diameters ranging from three to 12 inches and has 14 compressor stations with a combined 44,368 horsepower of compression.

Customers. Anadarko is the only significant shipper on the Dew gathering system. Anadarko s equity gas accounted for 213 MMcf/d of throughput during the nine months ended September 30, 2007, which represented approximately 98% of the total volume on the system.

Delivery Points. The Dew gathering system s primary delivery point is Pinnacle Gas Treating, Inc., which is described in more detail below, but it also has a connection to Kinder Morgan s Tejas pipeline.

Supply. Anadarko has drilled over 750 gross wells to date in the Bossier play and controls approximately 230,000 gross acres in the area. For the last three years, Anadarko has maintained an active drilling program in the Bossier play utilizing four or five rigs to drill approximately 30 gross wells per year. With this level of activity, we believe Anadarko has a drilling location inventory of over five years.

Pinnacle Gas Treating LLC

General. Pinnacle Gas Treating LLC includes our Pinnacle gathering system and our Bethel treating plant. Pinnacle Gas Treating provides sour gas gathering and treating service in Anderson, Freestone, Leon, Limestone and Robertson Counties of East Texas. The gathering system consists of 256 miles of pipeline with diameters ranging from three to 24 inches and one compressor station with 1,265 horsepower.

The Bethel treating plant, located in Anderson County, has total CO_2 treating capacity of 500 MMcf/d and nine long tons per day, or LTD, of sulfur treating capacity. We are currently expanding the plant by installing an additional 11 LTD of sulfur treating capacity, which we expect to have completed in 2008, in order to provide additional sour gas treating capacity for drilling in the area.

Average throughput on the Pinnacle gathering system for the year ended December 31, 2006 and the nine months ended September 30, 2007 was 307 MMcf/d and 300 MMcf/d, respectively, from approximately 70 receipt points.

Customers. Anadarko is the largest shipper on the Pinnacle gathering system with 272 MMcf/d of throughput for the nine months ended September 30, 2007, which represented approximately 91% of the total throughput on the system during such period. Eighty percent of Anadarko s throughput is equity production, which includes Bossier natural gas delivered from the Dew gathering system and several wells directly connected to the Pinnacle system that produce from the Cotton Valley Lime formations. The remaining 20% of Anadarko s throughput consists of natural gas purchased by Anadarko from third parties.

Other shippers on the Pinnacle gathering system are ConocoPhillips Company, Hunt Petroleum Corp., EnCana Oil & Gas (USA) Inc., Paragon Energy Inc. and Newfield Exploration Company. These shippers accounted for 27 MMcf/d for the nine months ended September 30, 2007, which represented approximately 9% of total throughput on the system during such period.

Delivery Points. The Pinnacle gathering system is connected to Enterprise Texas Pipeline, LP s pipeline, the Energy Transfer Fuels pipeline, the ETC Texas pipeline, Kinder Morgan s Tejas pipeline, the ATMOS Texas pipeline and the Enbridge Pipelines (East Texas) LP pipeline. These pipelines provide transportation to the Carthage, Waha and Houston Ship Channel market hubs in Texas.

Supply. The Pinnacle gathering system is well positioned to provide gathering and treating services to the five county area over which it extends. With an average of 400 wells drilled in each of the last five

100

Business

years, this area has experienced significant recent growth and, as of September 30, 2007, had a total well count exceeding 5,000 wells and production of over 1.5 Bcf/d.

With the recent drilling activity in the Cotton Valley Lime formations, which contain higher concentrations of H_2S and CO_2, we were able to obtain a commitment from a third-party producer that allows us to expand the Bethel treating facilities. With this expansion, we believe that we are well positioned to benefit from future sour gas production in the area.

Rocky Mountains

MIGC system

General. The MIGC system is a 264-mile interstate pipeline operating within the Powder River Basin of Wyoming that is regulated by the Federal Energy Regulatory Commission, or FERC. The MIGC system traverses the Powder River Basin from north to south, extending approximately 150 miles to Glenrock, Wyoming. As a result, the MIGC system is well positioned to provide transportation for the extensive natural gas volumes received from various coal-bed methane gathering systems and conventional gas processing plants throughout the Powder River Basin. MIGC offers both forward-haul and backhaul transportation services, and additional capacity is available from time to time on an interruptible basis.

Average throughput on the MIGC system for the year ended December 31, 2006 and the nine months ended September 30, 2007 was 126 MMcf/d and 137 MMcf/d, respectively, from approximately 20 receipt points.

MIGC recently completed the installation of, and placed into service, the Python compression station, which increased capacity on the MIGC system by approximately 50 MMcf/d. In April 2007, Anadarko entered into a firm transportation contract for 45 MMcf/d of this additional capacity. MIGC is currently certificated for 175 MMcf/d of firm transportation capacity, all of which is fully subscribed.

Customers. Anadarko is the largest firm shipper on the MIGC system, with approximately 72% and 71% of throughput for the year ended December 31, 2006 and the nine months ended September 30, 2007, respectively. For the year ended December 31, 2006 and the nine months ended September 30, 2007, Williams Production RMT Company and KFx Plant, LLC together accounted for approximately 28% and 29%, respectively, of throughput on the system.

Revenues on the MIGC system are generated from contract demand charges and volumetric fees paid by shippers under firm and interruptible gas transportation agreements. Our current firm transportation agreements range in term from approximately three months to 11 years. Of the current certificated capacity of 175 MMcf/d, 40 MMcf/d is contracted through October 2018, 45 MMcf/d is contracted through September 2012, 85 MMcf/d is contracted through January 2009 and 5 MMcf/d is contracted through December 2007. Most of our interruptible gas transportation agreements are month-to-month with the remainder generally having terms of less than one year. Approximately 64% and 85% of our revenues for the year ended December 31, 2006 and the nine months ended September 30, 2007, respectively, were associated with firm transportation demand charges.

Delivery Points. MIGC volumes can be redelivered to five interstate market pipelines, including the Williston Basin Interstate pipeline at the northern end of the Powder River Basin, the MGTC pipeline, a pipeline that supplies local markets in Wyoming, the Wyoming Interstate Company s Medicine Bow lateral pipeline, the Colorado Interstate Gas pipeline and the Kinder Morgan interstate pipeline at the southern end of the Powder River Basin near Glenrock, Wyoming.

Supply. Anadarko has an interest in over one million gross acres within the prolific Powder River Basin. It currently operates approximately 3,500 gross coal-bed methane wells and has non-operating interests in more than 3,400 additional gross coal-bed methane wells. Anadarko s acreage is

Business

approximately 50% developed with a substantial undeveloped acreage position in the expanding Big George coal fairway. The historical development pace on Anadarko acreage has been 600 to 800 gross wells per year, suggesting that a five- to seven-year development inventory remains.

Helper gathering system

General. The 67-mile Helper gathering system, located in Carbon County, Utah, was built to provide gathering services for Anadarko s coal-bed methane development of the Ferron Coal. The Helper gathering system provides gathering, dehydration, compression and treating services for coal-bed methane gas. The Helper gathering system has pipeline diameters ranging from four to 20 inches and includes two compressor stations with a combined 11,575 horsepower and two CO_2 treating facilities.

Average throughput on the Helper gathering system for the year ended December 31, 2006 and the nine months ended September 30, 2007, was 38 MMcf/d and 36 MMcf/d, respectively, from approximately 120 receipt points.

Customers. Anadarko is the largest shipper on the Helper gathering system. For the nine months ended September 30, 2007, Anadarko s equity production represented approximately 99% of the Helper gathering system s volume.

Delivery Points. The Helper gathering system delivers into the Questar Transportation Services Company s pipeline. Questar provides transportation to regional markets in Wyoming, Colorado and Utah and also delivers into the Kern River Pipeline, which provides transportation to markets in the western U.S., primarily California.

Supply. Helper Field is an Anadarko-operated field on the southwestern edge of the Uinta Basin that produces from the Cretaceous Ferron sands and coals. Helper Field consists of approximately 19,000 gross acres and currently has 116 gross producing wells. Cardinal Draw, which lies immediately to the east of Helper Field, currently has 24 gross producing wells and covers another approximately 15,000 gross acres.

In 2003, Anadarko entered into an agreement with Westport Oil and Gas Company, LP, which was acquired by Kerr-McGee Corporation in 2004, to gather volumes from its Cardinal Draw development play. Since the acquisition of Kerr-McGee by Anadarko in 2006, Anadarko has continued the development of the Cardinal Draw area. During the nine months ended September 30, 2007, Anadarko drilled 12 gross wells in the Cardinal Draw area and it has disclosed that it has identified an additional 56 drilling locations. Production in the Helper Field/Cardinal Draw area began in 1994 and since then has produced over 92 Bcf.

Clawson gathering system

General. The 47-mile Clawson gathering system, located in Carbon and Emery Counties of Utah, was built in 2001 to provide gathering services for Anadarko s coal-bed methane development of the Ferron Coal. The Clawson gathering system provides gathering, dehydration, compression and treating services for coal-bed methane gas. The Clawson gathering system has pipeline diameters ranging from four to 18 inches and includes one compressor station, with 8,810 horsepower, and a CO_2-treating facility.

Average throughput on the Clawson gathering system for the year ended December 31, 2006 and the nine months ended September 30, 2007 was 22 MMcf/d and 19 MMcf/d, respectively, from approximately 45 receipt points.

Customers. Anadarko is the largest shipper on the Clawson gathering system with approximately 96% of the total throughput delivered into the system during the nine months ended September 30, 2007. The remaining throughput on the system was comprised of production from third-party producers.

Table of Contents

Business

Delivery Points. The Clawson gathering system delivers into the Questar Transportation Services Company s pipeline.

Supply. Clawson Springs Field consists of 45 gross wells on approximately 7,200 gross acres. Production for Clawson Springs is primarily from the Cretaceous Ferron sands and coals. First gas sales in Clawson Springs occurred in 2001 and the field has produced over 54 Bcf.

Mid-Continent

Hugoton gathering system

General. The 1,753-mile Hugoton gathering system provides gathering service to the Hugoton field and is primarily located in Seward, Stevens, Grant and Morton Counties of Southwest Kansas and Texas County in Oklahoma.

Average throughput on the Hugoton gathering system for the year ended December 31, 2006 and the nine months ended September 30, 2007, was 117 MMcf/d and 123 MMcf/d, respectively, from approximately 1,500 receipt points. The Hugoton gathering system has pipeline diameters ranging from two to 26 inches and 44 compressor stations with a combined 130,720 horsepower of compression.

Customers. Anadarko is the largest customer on the Hugoton gathering system with 112 MMcf/d of average throughput during the nine months ended September 30, 2007, representing 86% of the total volume on the system during such period. Of these volumes, 63% represent Anadarko s equity production and 37% represent volumes purchased by Anadarko from third parties, including EOG Resources, Inc. and Merit Energy Company, among others.

Other significant shippers on the Hugoton gathering system, including DCP Midstream, LP, Oxy Oil and Gas, Pioneer Natural Resources USA, Inc. and ExxonMobil Gas & Power Marketing Company, LP, collectively comprised fourteen percent of the system throughput volume for the nine months ended September 30, 2007.

Delivery Points. The Hugoton gathering system is connected to DCP Midstream, LP s National Helium Plant, which extracts NGLs and helium and redelivers residue gas into the Panhandle Eastern Pipeline. The system is also connected to Pioneer Natural Resources Corporation s Satanta Plant for NGL processing and to the adjacent Mid-Continent Market Center, which provides access to the Panhandle Eastern pipeline, the Northern Natural Gas pipeline, the Natural Gas (NGPL) pipeline, the Southern Star pipeline, and the ANR pipeline. These pipelines provide transportation and market access to Midwestern and Northeastern markets.

Supply. The Hugoton Field is one of the largest natural gas fields in North America. Anadarko operates approximately 1,250 gross wells in the area and has an extensive acreage position with approximately 425,000 gross acres in the Hugoton Field. We believe that recent changes to the Hugoton and Panoma Council Grove Proration Orders will provide opportunities for significant recompletion, redrilling and density drilling activities.

By virtue of a farmout agreement between EOG Resources, Inc. and Anadarko, EOG gained the right to explore below the primary formations in the Hugoton Field. EOG plans to drill approximately 50 gross wells in 2008 and 60 gross wells in 2009 in proximity to the Hugoton gathering system. We believe we are well-positioned to gather volumes that may be produced from these new wells.

Table of Contents

Business

West Texas

Haley gathering system

General. The 87-mile Haley gathering system is located in Loving County, Texas and gathers Anadarko s production from the Delaware Basin. The Haley gathering system provides gathering and dehydration services and has pipeline diameters ranging from four to 16 inches.

Average throughput on the Haley gathering system for the year ended December 31, 2006 and the nine months ended September 30, 2007 was 139 MMcf/d and 185 MMcf/d, respectively, from approximately 50 wells. The Haley gathering system has experienced rapid growth as a result of Anadarko s successful drilling activity in the area. Since 2004, volumes gathered by the Haley system have increased from 13 MMcf/d to over 200 MMcf/d. Anadarko has maintained an active drilling program in the area, utilizing eight to nine rigs to explore and develop its Delaware Basin acreage.

Customers. Anadarko s and its partners production represented 99% of the Haley gathering system s throughput for the nine months ended September 30, 2007.

Delivery Points. The Haley gathering system has multiple delivery points. The primary delivery points are to the El Paso Natural Gas pipeline or the Enterprise GC, L.P. pipeline for ultimate delivery into Energy Transfer s Oasis pipeline. We also have the ability to deliver into Southern Union Energy Services pipeline for further delivery into the Oasis Pipeline. The pipelines at these delivery points provide transportation to both the Waha and Houston Ship Channel Markets.

Supply. In the greater Delaware basin, Anadarko has access to over 400,000 gross undeveloped acres, currently operates nine rigs and is a non-operating partner in three additional rigs. Within the area serviced by the Haley gathering system, over 60 gross wells have already been drilled and completed and we anticipate that four to five rigs will continuously operate on 100,000 Anadarko-controlled acres. We believe that this activity and Anadarko s controlled acreage indicate a 5 to 10-year drilling inventory on the acreage serviced by the Haley gathering system.

COMPETITION

Given that over 90% of the volume on our systems is owned or controlled by Anadarko and Anadarko has dedicated to us future production from acreage surrounding our gathering systems, we do not currently face significant competition for our natural gas volumes. In the future, we may face competition for Anadarko s production drilled outside the dedication and in attracting third-party volumes to our systems.

Competition on gathering systems

The natural gas gathering, compression, treating and transportation business is very competitive. Our competitors include other midstream companies, producers, intrastate and interstate pipelines. Competition for natural gas volumes is primarily based on reputation, commercial terms, reliability, service levels, location, available capacity, capital expenditures and fuel efficiencies. Our major competitors for each area include:

Ø

Dew gathering and Pinnacle gas treating: ETC Texas Pipeline, Ltd., Enbridge Pipelines (East Texas) LP, XTO Energy and Kinder Morgan Tejas Pipeline, LP.

Ø Helper and Clawson gathering systems: Questar Transportation Services Company.

Ø Hugoton gathering system: ONEOK Gas Gathering Company, DCP Midstream, LP, Pioneer Resources.

Ø Haley gathering system: Enterprise GC, LP, Southern Union Energy Services Company.

104

Table of Contents

Business

Competition on MIGC

MIGC competes with other pipelines that service regional market and transport gas volumes from the Powder River Basin to Glenrock, Wyoming. MIGC competitors seek to attract and connect new gas volumes throughout the Powder River Basin, including the volumes currently being transported on MIGC. An increase in competition could result from new pipeline installations or expansions by existing pipelines. Competitive factors include the commercial terms, available capacity, fuel efficiencies, the interconnected pipelines and gas quality issues MIGC major competitors are Fort Union Gas Gathering, L.L.C. and ThunderCreek Gas Services.

SAFETY AND MAINTENANCE

We are subject to regulation by the Pipeline and Hazardous Materials Safety Administration, or PHMSA, of the Department of Transportation, or the DOT, pursuant to the Natural Gas Pipeline Safety Act of 1968, or the NGPSA, and the Pipeline Safety Improvement Act of 2002, or the PSIA, which was recently reauthorized and amended by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006. The NGPSA regulates safety requirements in the design, construction, operation and maintenance of gas pipeline facilities, while the PSIA establishes mandatory inspections for all U.S. oil and natural gas transportation pipelines and some gathering lines in high-consequence areas. The PHMSA has developed regulations implementing the PSIA that require transportation pipeline operators to implement integrity management programs, including more frequent inspections and other measures to ensure pipeline safety in high consequence areas, such as high population areas, areas unusually sensitive to environmental damage and commercially navigable waterways. Our transportation pipeline system, MIGC, includes no high consequence areas and thus these particular integrity management programs are not applicable.

We or the entities in which we own an interest inspect our pipelines regularly using equipment rented from third-party suppliers. Third parties also assist us in interpreting the results of the inspections.

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

In addition, we are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes, the purposes of which are to protect the health and safety of workers, both generally and within the pipeline industry. In addition, the OSHA hazard communication standard, the Environmental Protection Agency, or EPA, community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that such information be provided to employees, state and local government authorities and citizens. We and the entities in which we own an interest are also subject to OSHA Process Safety Management regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process which involves a chemical at or above the specified thresholds or any process which involves flammable liquid or gas, pressurized tanks, caverns and wells in excess of 10,000 pounds at various locations. Flammable liquids stored in atmospheric tanks below their normal boiling points without the benefit of chilling or refrigeration are exempt. We have an internal program of inspection designed to monitor and enforce compliance with worker safety

Business

requirements. We believe that we are in material compliance with all applicable laws and regulations relating to worker health and safety.

REGULATION OF OPERATIONS

Regulation of pipeline gathering and transportation services, natural gas sales and transportation of NGLs may affect certain aspects of our business and the market for our products and services.

Interstate transportation pipeline regulation

MIGC, our interstate natural gas transportation system, is subject to regulation by FERC under the Natural Gas Act of 1938, or the NGA.

Under the NGA, FERC has authority to regulate natural gas companies that provide natural gas pipeline transportation services in interstate commerce. Federal regulation extends to such matters as:

- rates, services, and terms and conditions of service;
- the types of services MIGC may offer to its customers;
- the certification and construction of new facilities;
- the acquisition, extension, disposition or abandonment of facilities;
- the maintenance of accounts and records;
- relationships between affiliated companies involved in certain aspects of the natural gas business;
- the initiation and discontinuation of services;
- market manipulation in connection with interstate sales, purchases or transportation of natural gas; and
- participation by interstate pipelines in cash management arrangements.

Natural gas companies are prohibited from charging rates that have been determined not to be just and reasonable by FERC. In addition, FERC prohibits natural gas companies from unduly preferring or unreasonably discriminating against any person with respect to pipeline rates or terms and conditions of service.

The rates and terms and conditions for our interstate pipeline services are set forth in FERC-approved tariffs. Pursuant to FERC s jurisdiction over rates, existing rates may be challenged by complaint and proposed rate increases may be challenged by protest. Any successful complaint or protest against our rates could have an adverse impact on our revenues associated with providing transportation service.

Commencing in 2003, FERC issued a series of orders adopting rules for new Standards of Conduct for Transmission Providers (Order No. 2004), which apply to interstate natural gas pipelines and certain natural gas storage companies that provide storage services in interstate commerce. Order No. 2004 became effective in 2004. Among other matters, Order No. 2004 required interstate pipeline and storage companies to operate independently from their energy affiliates, prohibited interstate pipeline and storage companies from providing non-public transportation or shipper information to their energy affiliates, prohibited interstate pipeline and storage companies from favoring their energy affiliates in providing service and obligated interstate pipeline and storage companies to post on their websites a number of items of information concerning the company, including its organizational structure, facilities shared with energy affiliates, discounts given for service and instances in which the company has agreed to waive discretionary terms of its tariff.

Late in 2006, the D.C. Circuit vacated and remanded Order No. 2004 as it relates to natural gas transportation providers, including MIGC. The D.C. Circuit found that FERC had not adequately justified its expansion of the prior standards of conduct to include energy affiliates, and vacated the

Business

entire rule as it relates to natural gas transportation providers. On January 9, 2007, and as clarified on March 21, 2007, FERC issued an interim rule re-promulgating on an interim basis the standards of conduct that were not challenged before the court, while FERC decides how to respond to the court s decision on a permanent basis. The interim rule makes the standards of conduct apply to the relationship between natural gas transportation providers and their marketing affiliates, but not to energy affiliates who are not also marketing affiliates. Several companies requested rehearing and clarification of the interim rule. The March 21, 2007 order on clarification granted some of the requested clarifications and stated that FERC would address the other requests in its proceeding establishing a permanent rule. FERC has issued a notice of proposed rulemaking, or NOPR, that proposes permanent standards of conduct that FERC states will avoid the aspects of the previous standards of conduct rejected by the court. With respect to natural gas transportation providers, the NOPR proposes (1) that the permanent standards of conduct apply only to the relationship between natural gas transportation providers and their marketing affiliates, and (2) to make permanent the changes adopted in the interim rule permitting risk management employees to be shared by natural gas transportation providers and their marketing affiliates and requiring that tariff waivers be maintained in a written waiver log and available upon request.

On July 7, 2004, FERC issued an order providing MIGC with a partial waiver of the independent functioning and information access provisions of the standards of conduct. FERC has stated that waivers of the standards of conduct have not been impacted by the D.C. Circuit s decision to vacate the attempted expansion of the standards of conduct as to natural gas transmission providers, by the implementation of the interim rule, or by the currently pending NOPR. Nonetheless, we have no way to predict with certainty the scope of FERC s permanent rules on the standards of conduct. However, we do not believe that MIGC will be affected by any action taken previously or in the future on these matters in a fashion which is materially different than that affecting similarly situated natural gas service providers.

In May 2005, FERC issued a policy statement permitting the inclusion of an income tax allowance in the cost of service-based rates of a pipeline organized as a tax pass-through partnership entity, if the pipeline proves that the ultimate owner of its equity interests has an actual or potential income tax liability on public utility income. The policy statement also provides that whether a pipeline s owners have such actual or potential income tax liability will be reviewed by FERC on a case-by-case basis. In August 2005, FERC dismissed requests for rehearing of its new policy statement. On December 16, 2005, FERC issued its first significant case-specific review of the income tax allowance issue in a pipeline partnership s rate case. FERC reaffirmed its new income tax allowance policy and directed the subject pipeline to provide certain evidence necessary for the pipeline to determine its income tax allowance. The new tax allowance policy and the December 16, 2005 order were appealed to the D.C. Circuit. The D.C. Circuit issued an order on May 29, 2007 in which it denied these appeals and upheld FERC s new tax allowance policy and the application of that policy in the December 16, 2005 order on all points subject to appeal. The D.C. Circuit denied rehearing of the May 29, 2007 decision on August 20, 2007, and the D.C. Circuit s decision is final.

On December 8, 2006, FERC issued another order addressing the income tax allowance in rates. In the December 8, 2006 order, FERC refined and reaffirmed prior statements regarding its income tax allowance policy, and notably raised a new issue regarding the implication of the policy statement for publicly traded partnerships. It noted that the tax deferral features of a publicly traded partnership may cause some investors to receive, for some indeterminate duration, cash distributions in excess of their taxable income, which FERC characterized as a tax savings. FERC stated that it is concerned that this created an opportunity for those investors to earn an additional return, funded by ratepayers. Responding to this concern, FERC chose to adjust the pipeline s equity rate of return downward based on the percentage by which the publicly traded partnership s cash flow exceeded taxable income. On February 7, 2007, the pipeline filed a request for rehearing on this issue, which is currently pending

Table of Contents

Business

before FERC. The ultimate outcome of this proceeding is not certain and could result in changes to FERC s treatment of income tax allowances in cost of service and to potential adjustment in a future rate case of our pipelines respective equity rate of return that underlies its recourse rates to the extent that cash distributions in excess of taxable income are allowed to some unitholders. If FERC were to disallow a substantial portion of MIGC s income tax allowance, it may cause its recourse rates to be set at a level that is different, and in some instances lower, than the level otherwise in effect.

On July 19, 2007, FERC issued a proposed policy statement regarding the composition of proxy groups for determining the appropriate return on equity for natural gas and oil pipelines. The proposed policy statement would permit the inclusion of distributions capped at a master limited partnership s reported earnings in calculating the equity returns of a proxy group of pipeline enterprises under the Discounted Cash Flow, or DCF, analysis. The determination of which master limited partnerships should be included will be made on a case by case basis, after a review of whether a master limited partnership s earnings have been stable over a multi-year period. In November 2007, the FERC requested additional comments and announced a technical conference regarding the method to be used for creating growth forecasts for publicly traded partnerships. FERC proposes to apply the final policy statement to all natural gas rate cases that have not completed the hearing phase as of the date FERC issues the final policy statement. FERC s proposed policy statement is subject to change based on comments it has received, and therefore, we cannot predict the scope of the final policy statement.

On August 8, 2005, Congress enacted the Energy Policy Act of 2005, or the EPAct 2005. Among other matters, EPAct 2005 amends the NGA to add an anti-manipulation provision which makes it unlawful for any entity to engage in prohibited behavior in contravention of rules and regulations to be prescribed by FERC and, furthermore, provides FERC with additional civil penalty authority. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-manipulation provision of EPAct 2005, and subsequently denied rehearing. The rules make it unlawful for any entity, directly or indirectly: (1) in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC or the purchase or sale of transportation services subject to the jurisdiction of FERC to use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) to engage in any act or practice that operates as a fraud or deceit upon any person. The new anti-manipulation rules apply to interstate gas pipelines and storage companies and intrastate gas pipelines and storage companies that provide interstate services, such as Section 311 service, as well as otherwise non-jurisdictional entities to the extent the activities are conducted in connection with gas sales, purchases or transportation subject to FERC jurisdiction. The new anti-manipulation rules do not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but only to the extent such transactions do not have a nexus to jurisdictional transactions. EPAct 2005 also amends the NGA and the NGPA to give FERC authority to impose civil penalties for violations of these statutes, up to $1,000,000 per day per violation for violations occurring after August 8, 2005. In connection with this enhanced civil penalty authority, FERC issued a policy statement on enforcement to provide guidance regarding the enforcement of the statutes, orders, rules and regulations it administers, including factors to be considered in determining the appropriate enforcement action to be taken. Should we fail to comply with all applicable FERC-administered statutes, rule, regulations and orders, we could be subject to substantial penalties and fines.

Gathering pipeline regulation

Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC. We believe that our natural gas pipelines meet the traditional tests that FERC has used to determine that a pipeline is a gathering pipeline and is, therefore, not subject to FERC jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services, however, is the subject of substantial, on-going litigation, so the classification and regulation of our gathering

Business

facilities are subject to change based on future determinations by FERC, the courts or Congress. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and complaint-based rate regulation. In recent years, FERC has taken a more light-handed approach to regulation of the gathering activities of interstate pipeline transmission companies, which has resulted in a number of such companies transferring gathering facilities to unregulated affiliates. As a result of these activities, natural gas gathering may begin to receive greater regulatory scrutiny at both the state and federal levels. Our natural gas gathering operations could be adversely affected should they be subject to more stringent application of state or federal regulation of rates and services. Our natural gas gathering operations also may be or become subject to additional safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

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

During the 2007 legislative session, the Texas State Legislature passed H.B. 3273, or the Competition Bill, and H.B. 1920, or the LUG Bill. The Texas Competition Bill and LUG Bill contain provisions applicable to gathering facilities. The Competition Bill allows the Railroad Commission of Texas, or the TRRC, the ability to use either a cost-of-service method or a market-based method for setting rates for natural gas gathering in formal rate proceedings. It also gives the TRRC specific authority to enforce its statutory duty to prevent discrimination in natural gas gathering, to enforce the requirement that parties participate in an informal complaint process and to punish purchasers, transporters and gatherers for taking discriminatory actions against shippers and sellers. The LUG Bill modifies the informal complaint process at the TRRC with procedures unique to lost and unaccounted for gas issues. It extends the types of information that can be requested and gives the TRRC the authority to make determinations and issue orders in specific situations. Both the Competition Bill and the LUG Bill became effective September 1, 2007. We cannot predict what effect, if any, either the Competition Bill or the LUG Bill might have on our gathering operations.

ENVIRONMENTAL MATTERS

General

Our operation of pipelines, plants and other facilities for the gathering, compressing, treating and transporting of natural gas and other products is subject to stringent and complex federal, state and local laws and regulations relating to the protection of the environment. As an owner or operator of

Business

these facilities, we must comply with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact our business activities in many ways, such as:

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

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 orders enjoining future operations or imposing additional compliance requirements. Certain environmental statutes impose strict joint and several liability for costs required to clean up and restore sites where substances, hydrocarbons or wastes have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment.

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

We do not believe that compliance with federal, state or local environmental laws and regulations will have a material adverse effect on our business, financial position or results of operations or cash flows. In addition, we believe that the various environmental activities in which we are presently engaged are not expected to materially interrupt or diminish our operational ability to gather, compress, treat and transport natural gas. We cannot assure you, however, that future events, such as changes in existing laws or enforcement policies, the promulgation of new laws or regulations or the development or discovery of new facts or conditions will not cause us to incur significant costs. Below is a discussion of the material environmental laws and regulations that relate to our business. We believe that we are in substantial compliance with all of these environmental laws and regulations.

Hazardous substances and waste

Our operations are subject to environmental laws and regulations relating to the management and release of hazardous substances, solid and hazardous wastes and petroleum hydrocarbons. These laws generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous waste and may impose strict joint and several liability for the investigation and remediation of affected areas where hazardous substances may have been released or disposed. For instance, the Comprehensive Environmental Response, Compensation, and Liability Act, referred to as CERCLA or the Superfund law, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that contributed to the release of a hazardous substance into the environment. These persons include current and prior owners or operators of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these persons may be subject to joint and several strict liability for the costs

Table of Contents