Western Gas Partners LP
Form 10-Q
October 29, 2014
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2014

Or

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

For the transition period from to

Commission file number: 001-34046

WESTERN GAS PARTNERS, LP
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	26-1075808 (I.R.S. Employer Identification No.)
1201 Lake Robbins Drive The Woodlands, Texas (Address of principal executive offices)	77380 (Zip Code)

(832) 636-6000
(Registrant's telephone number, including area code)

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No o

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

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

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

There were 119,070,104 common units outstanding as of October 27, 2014.

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DEFINITIONS

As generally used within the energy industry and in this quarterly report on Form 10-Q, the identified terms have the following meanings:

Barrel or Bbl: 42 U.S. gallons measured at 60 degrees Fahrenheit.

Btu: British thermal unit; the approximate amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Condensate: A natural gas liquid with a low vapor pressure mainly composed of propane, butane, pentane and heavier hydrocarbon fractions.

Cryogenic: The process in which liquefied gases, such as liquid nitrogen or liquid helium, are used to bring volumes to very low temperatures (below approximately -238 degrees Fahrenheit) to separate natural gas liquids from natural gas. Through cryogenic processing, more natural gas liquids are extracted than when traditional refrigeration methods are used.

Drip condensate: Heavier hydrocarbon liquids that fall out of the natural gas stream and are recovered in the gathering system without processing.

Fractionation: The process of applying various levels of higher pressure and lower temperature to separate a stream of natural gas liquids into ethane, propane, normal butane, isobutane and natural gasoline for end-use sale.

Imbalance: Imbalances result from (i) differences between gas volumes nominated by customers and gas volumes received from those customers and (ii) differences between gas volumes received from customers and gas volumes delivered to those customers.

MBbls/d: One thousand barrels per day.

MMBtu: One million British thermal units.

MMcf/d: One million cubic feet per day.

Natural gas liquid(s) or NGL(s): The combination of ethane, propane, normal butane, isobutane and natural gasolines that, when removed from natural gas, become liquid under various levels of higher pressure and lower temperature.

Residue: The natural gas remaining after being processed or treated.

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PART I. FINANCIAL INFORMATION
Item 1. Financial Statements
WESTERN GAS PARTNERS, LP
CONSOLIDATED STATEMENTS OF INCOME
(UNAUDITED)

	Three Months Ended September 30,		Nine Months Ended September 30,	
thousands except per-unit amounts	2014	2013 [1]	2014	2013 [1]
Revenues – affiliates				
Gathering, processing and transportation of natural gas and natural gas liquids	$104,258	$83,606	$288,392	$218,680
Natural gas, natural gas liquids and condensate sales	138,464	129,411	415,715	371,077
Other, net	2,778	108	4,349	1,253
Total revenues – affiliates	245,500	213,125	708,456	591,010
Revenues – third parties				
Gathering, processing and transportation of natural gas and natural gas liquids	64,098	47,175	182,663	124,791
Natural gas, natural gas liquids and condensate sales	11,630	11,915	37,471	31,539
Other, net	5,237	1,287	7,276	3,330
Total revenues – third parties	80,965	60,377	227,410	159,660
Total revenues	326,465	273,502	935,866	750,670
Equity income, net [2]	19,063	4,520	41,322	11,944
Operating expenses				
Cost of product [3]	108,393	93,516	318,428	270,059
Operation and maintenance [3]	53,657	42,757	145,064	121,165
General and administrative [3]	7,889	7,276	24,304	22,228
Property and other taxes	6,564	6,649	20,718	18,520
Depreciation, amortization and impairments	45,651	37,615	130,009	106,551
Total operating expenses	222,154	187,813	638,523	538,523
Operating income	123,374	90,209	338,665	224,091
Interest income, net – affiliates	4,225	4,225	12,675	12,675
Interest expense	(20,878)	(13,018)	(55,703)	(37,483)
Other income (expense), net	97	439	788	1,612
Income before income taxes	106,818	81,855	296,425	200,895
Income tax (benefit) expense	278	(27)	276	4,192
Net income	106,540	81,882	296,149	196,703
Net income attributable to noncontrolling interest	3,863	3,376	11,005	7,467
Net income attributable to Western Gas Partners, LP	$102,677	$78,506	$285,144	$189,236
Limited partners’ interest in net income:				
Net income attributable to Western Gas Partners, LP	$102,677	$78,506	$285,144	$189,236
Pre-acquisition net (income) loss allocated to Anadarko	—	(106)	956	(4,616)
General partner interest in net (income) loss [4]	(31,058)	(18,693)	(83,939)	(47,733)
Limited partners’ interest in net income [4]	71,619	59,707	202,161	136,887
Net income per common unit – basic and diluted	$0.60	$0.53	$1.71	$1.26
Weighted average common units outstanding – basic and diluted	119,068	112,143	118,326	108,540

(1) Financial information has been recast to include the financial position and results attributable to the TEFR Interests. See Note 1 and Note 2.

(2) Income earned from equity investments is classified as affiliate. See Note 1.

(3) Cost of product includes product purchases from Anadarko (as defined in Note 1) of $22.7 million and $74.6 million for the three and nine months ended September 30, 2014, respectively, and $33.8 million and $97.8 million for the three and nine months ended September 30, 2013, respectively. Operation and maintenance includes charges from Anadarko of $14.6 million and $42.5 million for the three and nine months ended September 30, 2014, respectively, and $13.5 million and $41.0 million for the three and nine months ended September 30, 2013, respectively. General and administrative includes charges from Anadarko of $6.6 million and $19.9 million for the three and nine months ended September 30, 2014, respectively, and $5.9 million and $17.3 million for the three and nine months ended September 30, 2013, respectively. See Note 5.

(4) Represents net income earned on and subsequent to the date of acquisition of the Partnership assets (as defined in Note 1). See Note 4.

See accompanying Notes to Consolidated Financial Statements.

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WESTERN GAS PARTNERS, LP
CONSOLIDATED BALANCE SHEETS
(UNAUDITED)

thousands except number of units	September 30, 2014	December 31, 2013 (1)
ASSETS		
Current assets		
Cash and cash equivalents	$67,837	$100,728
Accounts receivable, net (2)	126,345	84,060
Other current assets (3)	6,773	10,022
Total current assets	200,955	194,810
Note receivable – Anadarko	260,000	260,000
Property, plant and equipment		
Cost	4,754,279	4,239,100
Less accumulated depreciation	986,692	855,845
Net property, plant and equipment	3,767,587	3,383,255
Goodwill	105,336	105,336
Other intangible assets	52,561	53,606
Equity investments	639,191	593,400
Other assets	28,910	27,401
Total assets	$5,054,540	$4,617,808
LIABILITIES, EQUITY AND PARTNERS' CAPITAL		
Current liabilities		
Accounts and natural gas imbalance payables (4)	$27,011	$39,589
Accrued ad valorem taxes	21,083	13,860
Income taxes payable	258	—
Accrued liabilities (5)	152,878	137,011
Total current liabilities	201,230	190,460
Long-term debt	2,082,914	1,418,169
Deferred income taxes	780	37,998
Asset retirement obligations and other	85,903	79,145
Total long-term liabilities	2,169,597	1,535,312
Total liabilities	2,370,827	1,725,772
Equity and partners' capital		
Common units (119,070,104 and 117,322,812 units issued and outstanding at September 30, 2014, and December 31, 2013, respectively)	2,524,313	2,431,193
General partner units (2,430,007 and 2,394,345 units issued and outstanding at September 30, 2014, and December 31, 2013, respectively)	89,150	78,157
Net investment by Anadarko	—	312,092
Total partners' capital	2,613,463	2,821,442
Noncontrolling interest	70,250	70,594
Total equity and partners' capital	2,683,713	2,892,036
Total liabilities, equity and partners' capital	$5,054,540	$4,617,808

(1) Financial information has been recast to include the financial position and results attributable to the TEFR Interests. See Note 1 and Note 2.

(2) Accounts receivable, net includes amounts receivable from affiliates (as defined in Note 1) of $87.3 million and $47.9 million as of September 30, 2014, and December 31, 2013, respectively.

(3)

Other current assets includes natural gas imbalance receivables from affiliates of $0.1 million as of September 30, 2014, and December 31, 2013.

(4) Accounts and natural gas imbalance payables includes amounts payable to affiliates of $0.1 million and $2.3 million as of September 30, 2014, and December 31, 2013, respectively.

(5) Accrued liabilities includes amounts payable to affiliates of zero and $0.1 million as of September 30, 2014, and December 31, 2013, respectively.

See accompanying Notes to Consolidated Financial Statements.

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WESTERN GAS PARTNERS, LP
CONSOLIDATED STATEMENT OF EQUITY AND PARTNERS' CAPITAL
(UNAUDITED)

	Partners' Capital				
thousands	Net Investment by Anadarko	Common Units	General Partner Units	Noncontrolling Interest	Total
Balance at December 31, 2013 [1]	$312,092	$2,431,193	$78,157	$70,594	$2,892,036
Net income (loss)	(956)	202,161	83,939	11,005	296,149
Issuance of common and general partner units, net of offering expenses	—	99,274	2,467	—	101,741
Distributions to noncontrolling interest owner	—	—	—	(11,349)	(11,349)
Distributions to unitholders	—	(221,677)	(75,336)	—	(297,013)
Acquisitions from affiliates	(372,784)	16,534	—	—	(356,250)
Contributions of equity-based compensation from Anadarko	—	2,471	50	—	2,521
Net pre-acquisition contributions from Anadarko [2]	23,488	—	—	—	23,488
Net distributions to Anadarko of other assets	—	(6,271)	(127)	—	(6,398)
Elimination of net deferred tax liabilities	38,160	—	—	—	38,160
Other	—	628	—	—	628
Balance at September 30, 2014	$—	$2,524,313	$89,150	$70,250	$2,683,713

(1) Financial information has been recast to include the financial position and results attributable to the TEFR Interests. See Note 1 and Note 2.

(2) Includes deferred taxes on capitalized interest of $0.3 million associated with the acquisition of the TEFR Interests as of September 30, 2014.

See accompanying Notes to Consolidated Financial Statements.

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WESTERN GAS PARTNERS, LP
CONSOLIDATED STATEMENTS OF CASH FLOWS
(UNAUDITED)

	Nine Months Ended September 30,	
thousands	2014	2013 [1]
Cash flows from operating activities		
Net income	$296,149	$196,703
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization and impairments	130,009	106,551
Non-cash equity-based compensation expense	3,210	2,564
Deferred income taxes	642	29,216
Debt-related amortization and other items, net	2,045	1,756
Equity income, net [2]	(41,322)	(11,944)
Distributions from equity investment earnings [2]	43,061	15,563
Changes in assets and liabilities:		
(Increase) decrease in accounts receivable, net	(41,408)	(27,387)
Increase (decrease) in accounts and natural gas imbalance payables and accrued liabilities, net	9,736	6,818
Change in other items, net	1,645	(2,523)
Net cash provided by operating activities	403,767	317,317
Cash flows from investing activities		
Capital expenditures	(492,287)	(469,678)
Contributions in aid of construction costs from affiliates	183	—
Acquisitions from affiliates	(372,393)	(469,884)
Acquisitions from third parties	—	(240,274)
Investments in equity affiliates	(63,267)	(252,308)
Distributions from equity investments in excess of cumulative earnings [2]	14,387	—
Proceeds from the sale of assets to affiliates	—	82
Proceeds from the sale of assets to third parties	5	14
Net cash used in investing activities	(913,372)	(1,432,048)
Cash flows from financing activities		
Borrowings, net of debt issuance costs	1,136,878	842,566
Repayments of debt	(480,000)	(495,000)
Increase (decrease) in outstanding checks	2,908	(3,335)
Proceeds from the issuance of common and general partner units, net of offering expenses	101,502	427,848
Distributions to unitholders	(297,013)	(215,115)
Contributions from noncontrolling interest owner	—	2,247
Distributions to noncontrolling interest owner	(11,349)	(8,001)
Net contributions from Anadarko	23,788	181,904
Net cash provided by financing activities	476,714	733,114
Net increase (decrease) in cash and cash equivalents	(32,891)	(381,617)
Cash and cash equivalents at beginning of period	100,728	419,981
Cash and cash equivalents at end of period	$67,837	$38,364
Supplemental disclosures		
Net distributions to Anadarko of other assets	$6,398	$4,080
Interest paid, net of capitalized interest	43,504	34,974
Taxes paid (reimbursements received)	(340)	—
Capital lease asset transfer [3]	4,833	—

(1) Financial information has been recast to include the financial position and results attributable to the TEFR Interests. See Note 1 and Note 2.
(2) Income earned on, distributions from and contributions to equity investments are classified as affiliate. See Note 1.
(3) For the nine months ended September 30, 2014, represents transfers of $0.2 million and $4.6 million from other current assets and other long-term assets, respectively, associated with the capital lease components of a processing agreement. See Note 6.

See accompanying Notes to Consolidated Financial Statements.

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WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

1. DESCRIPTION OF BUSINESS AND BASIS OF PRESENTATION

General. Western Gas Partners, LP is a growth-oriented Delaware master limited partnership formed by Anadarko Petroleum Corporation in 2007 to own, operate, acquire and develop midstream energy assets.
For purposes of these consolidated financial statements, the “Partnership” refers to Western Gas Partners, LP and its subsidiaries. The Partnership’s general partner, Western Gas Holdings, LLC (the “general partner” or “GP”), is owned by Western Gas Equity Partners, LP (“WGP”), a Delaware master limited partnership formed by Anadarko Petroleum Corporation in September 2012 to own the Partnership’s general partner, as well as a significant limited partner interest in the Partnership (see Western Gas Equity Partners, LP below). Western Gas Equity Holdings, LLC is WGP’s general partner and is a wholly owned subsidiary of Anadarko Petroleum Corporation. “Anadarko” refers to Anadarko Petroleum Corporation and its subsidiaries, excluding the Partnership and the general partner, and “affiliates” refers to subsidiaries of Anadarko, excluding the Partnership, and includes equity interests in Fort Union Gas Gathering, LLC (“Fort Union”), White Cliffs Pipeline, LLC (“White Cliffs”), Rendezvous Gas Services, LLC (“Rendezvous”), Enterprise EF78, LLC (the “Mont Belvieu JV”), Texas Express Pipeline LLC (“TEP”), Texas Express Gathering LLC (“TEG”) and Front Range Pipeline LLC (“FRP”) (see Note 2). The interests in TEP, TEG and FRP are referred to collectively as the “TEFR Interests.” All income earned on, distributions from and contributions to the Partnership’s equity investments are considered to be affiliate transactions. “Equity investment throughput” refers to the Partnership’s 14.81% share of average Fort Union throughput and 22% share of average Rendezvous throughput, but excludes throughput measured in barrels, consisting of the Partnership’s 10% share of average White Cliffs throughput, 25% share of average Mont Belvieu JV throughput, 20% share of average TEP and TEG throughput and 33.33% share of average FRP throughput. The “DJ Basin complex” refers to the Platte Valley system, Wattenberg system, and Lancaster plant, all of which were combined into a single complex in the first quarter of 2014.
The Partnership is engaged in the business of gathering, processing, compressing, treating and transporting natural gas, condensate, NGLs and crude oil for Anadarko, as well as for third-party producers and customers. As of September 30, 2014, the Partnership’s assets and investments accounted for under the equity method consisted of the following:

	Owned and Operated	Operated Interests	Non-Operated Interests	Equity Interests
Natural gas gathering systems	13	1	5	2
NGL gathering systems	—	—	—	2
Natural gas treating facilities	8	—	—	1
Natural gas processing facilities	9	3	—	2
NGL pipelines	3	—	—	2
Natural gas pipelines	3	—	—	—
Oil pipeline	—	—	—	1

These assets and investments are located in the Rocky Mountains (Colorado, Utah and Wyoming), the Mid-Continent (Kansas and Oklahoma), north-central Pennsylvania and Texas. The Partnership completed construction of Train I at the Lancaster processing plant (located in the DJ Basin complex) in Northeast Colorado in April 2014, and is constructing Train II at the same plant with operations expected to commence in the second quarter of 2015.

Western Gas Equity Partners, LP. WGP owns the following types of interests in the Partnership: (i) the 2.0% general partner interest and all of the incentive distribution rights (“IDRs”) in the Partnership, both owned through WGP’s 100% ownership of the Partnership’s general partner and (ii) a significant limited partner interest (see Holdings of Partnership equity in Note 4). WGP has no independent operations or material assets other than its partnership interests in the Partnership.

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WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

1. DESCRIPTION OF BUSINESS AND BASIS OF PRESENTATION (CONTINUED)

Basis of presentation. The consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States (“GAAP”). The consolidated financial statements include the accounts of the Partnership and entities in which it holds a controlling financial interest. All significant intercompany transactions have been eliminated. Investments in non-controlled entities over which the Partnership exercises significant influence are accounted for under the equity method. The Partnership proportionately consolidates its 33.75% share of the assets, liabilities, revenues and expenses attributable to the Non-Operated Marcellus Interest and Anadarko-Operated Marcellus Interest (see Note 2) and its 50% share of the assets, liabilities, revenues and expenses attributable to the Newcastle system in the accompanying consolidated financial statements. The 25% membership interest in Chipeta Processing LLC (“Chipeta”) held by a third-party member is reflected within noncontrolling interest in the consolidated financial statements for all periods presented.
In preparing financial statements in accordance with GAAP, management makes informed judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses. Management evaluates its estimates and related assumptions regularly, using historical experience and other methods considered reasonable under the particular circumstances. Changes in facts and circumstances or additional information may result in revised estimates and actual results may differ from these estimates. Effects on the business, financial condition and results of operations resulting from revisions to estimates are recognized when the facts that give rise to the revisions become known. The information furnished herein reflects all normal recurring adjustments which are, in the opinion of management, necessary for a fair presentation of the consolidated financial statements, and certain prior-period amounts have been reclassified to conform to the current-year presentation.
Certain information and note disclosures commonly included in annual financial statements have been condensed or omitted pursuant to the rules and regulations of the Securities and Exchange Commission (“SEC”). Accordingly, the accompanying consolidated financial statements and notes should be read in conjunction with the Partnership’s 2013 Form 10-K, as filed with the SEC on February 28, 2014, certain sections of which were recast to reflect the results of the TEFR Interests in the Partnership’s Current Report on Form 8-K, as filed with the SEC on August 27, 2014. Management believes that the disclosures made are adequate to make the information not misleading.

Presentation of Partnership assets. The “Partnership assets” refer collectively to the assets owned and interests accounted for under the equity method by the Partnership as of September 30, 2014. Because Anadarko controls the Partnership through its ownership and control of WGP, which owns the Partnership’s general partner, each acquisition of Partnership assets from Anadarko has been considered a transfer of net assets between entities under common control. As such, the Partnership assets acquired from Anadarko were initially recorded at Anadarko’s historic carrying value, which did not correlate to the total acquisition price paid by the Partnership. Further, after an acquisition of Partnership assets from Anadarko, the Partnership may be required to recast its financial statements to include the activities of the Partnership assets as of the date of common control. See Note 2.
For those periods requiring recast, the consolidated financial statements for periods prior to the Partnership’s acquisition of the Partnership assets from Anadarko have been prepared from Anadarko’s historical cost-basis accounts and may not necessarily be indicative of the actual results of operations that would have occurred if the Partnership had owned the Partnership assets during the periods reported. Net income attributable to the Partnership assets acquired from Anadarko for periods prior to the Partnership’s acquisition of the Partnership assets is not allocated to the limited partners for purposes of calculating net income per common unit.

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WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

1. DESCRIPTION OF BUSINESS AND BASIS OF PRESENTATION (CONTINUED)

Equity investments. The following table presents the activity in the Partnership's equity investments for the nine months ended September 30, 2014:

	Equity Investments							
thousands	Fort Union	White Cliffs	Rendezvous	Mont Belvieu JV	TEG	TEP	FRP	Total
Balance at December 31, 2013	$25,172	$35,039	$60,928	$122,480	$16,649	$197,731	$135,401	$593,400
Investment earnings (loss), net of amortization	4,811	8,385	1,180	22,872	466	3,488	120	41,322
Contributions	—	10,456	—	3,956	352	6,263	40,033	61,060
Capitalized interest	—	—	—	—	—	—	857	857
Distributions	(4,619)	(7,949)	(2,636)	(24,423)	(373)	(2,938)	(123)	(43,061)
Distributions in excess of cumulative earnings [1]	—	(891)	(1,993)	—	(338)	(5,321)	(5,844)	(14,387)
Balance at September 30, 2014	$25,364	$45,040	$57,479	$124,885	$16,756	$199,223	$170,444	$639,191

(1) Distributions in excess of cumulative earnings, classified as investing cash flows in the consolidated statements of cash flows, is calculated on an individual investment basis.

Recently issued accounting standards. Accounting Standards Update ("ASU") 2014-09, Revenue from Contracts with Customers, supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, and industry-specific guidance in Subtopic 932-605, Extractive Activities—Oil and Gas—Revenue Recognition, and requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. This ASU is effective for annual and interim periods beginning in 2017 and is required to be adopted using one of two retrospective application methods, with no early adoption permitted. The Partnership is currently evaluating the impact of the adoption of this ASU on its consolidated financial statements.

ASU 2014-08, Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity, changes the criteria for reporting discontinued operations and requires additional disclosures, both for discontinued operations and for individually significant dispositions and assets classified as held for sale not qualifying as discontinued operations. This ASU is effective for annual and interim periods beginning in 2015, with early adoption permitted for disposals or for assets classified as held for sale that have not been reported in previously issued financial statements. The Partnership early adopted this ASU on a prospective basis beginning with the first quarter of 2014. The adoption did not have a material impact on the Partnership's consolidated financial statements.

ASU 2013-11, Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists, requires that an unrecognized tax benefit, or a portion of an unrecognized tax benefit, be presented in the financial statements as a reduction to a deferred tax asset, except in certain circumstances. This ASU is effective for annual and interim periods beginning in 2014. The Partnership adopted this ASU on a prospective basis beginning with the first quarter of 2014. The adoption did not have a material impact on the Partnership's consolidated financial statements.

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WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

2. ACQUISITIONS

The following table presents the acquisitions completed by the Partnership during 2014 and 2013, and identifies the funding sources for such acquisitions:

thousands except unit and percent amounts	Acquisition Date	Percentage Acquired		Borrowings	Cash On Hand	Common Units Issued
Non-Operated Marcellus Interest (1)	03/01/2013	33.75	%	$250,000	$215,500	449,129
Anadarko-Operated Marcellus Interest (2)	03/08/2013	33.75	%	133,500	—	—
Mont Belvieu JV (3)	06/05/2013	25	%	—	78,129	—
OTTCO (4)	09/03/2013	100	%	27,500	—	—
TEFR Interests (5)	03/03/2014	Various (5)		350,000	6,250	308,490

(1) The Partnership acquired Anadarko's 33.75% interest (non-operated) in the Liberty and Rome gas gathering systems, serving production from the Marcellus shale in north-central Pennsylvania. The interest acquired is referred to as the "Non-Operated Marcellus Interest." In connection with the issuance of the common units, the Partnership's general partner purchased 9,166 general partner units for consideration of $0.5 million to maintain its 2.0% general partner interest in the Partnership.

(2) The Partnership acquired a 33.75% interest in each of the Larry's Creek, Seely and Warrensville gas gathering systems, which are operated by Anadarko and serve production from the Marcellus shale in north-central Pennsylvania, from a third party. The interest acquired is referred to as the "Anadarko-Operated Marcellus Interest." During the third quarter of 2013, the Partnership recorded a $1.1 million decrease in the assets acquired and liabilities assumed in the acquisition, representing the final purchase price allocation.

(3) The Partnership acquired a 25% interest in the Mont Belvieu JV, an entity formed to design, construct, and own two fractionation trains located in Mont Belvieu, Texas, from a third party. The interest acquired is accounted for under the equity method of accounting.

(4) The Partnership acquired Overland Trail Transmission, LLC ("OTTCO"), a Delaware limited liability company, from a third party. OTTCO owns and operates an intrastate pipeline that connects the Partnership's Red Desert and Granger complexes in southwestern Wyoming.

(5) The Partnership acquired a 20% interest in each of TEG and TEP and a 33.33% interest in FRP from Anadarko. These assets gather and transport NGLs primarily from the Anadarko and Denver-Julesburg Basins. The interests in these entities are accounted for under the equity method of accounting. In connection with the issuance of the common units, the Partnership's general partner purchased 6,296 general partner units for consideration of $0.4 million to maintain its 2.0% general partner interest in the Partnership.

TEFR Interests acquisition. Because the acquisition of the TEFR Interests was a transfer of net assets between entities under common control, the Partnership's historical financial statements previously filed with the SEC have been recast in this Form 10-Q to include the results attributable to the TEFR Interests for all periods presented. The consolidated financial statements for periods prior to the Partnership's acquisition of the TEFR Interests have been prepared from Anadarko's historical cost-basis accounts and may not necessarily be indicative of the actual results of operations that would have occurred if the Partnership had owned the TEFR Interests during the periods reported.

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2. ACQUISITIONS (CONTINUED)

The following table presents the impact of the TEFR Interests on revenues, equity income (loss), net and net income (loss) as presented in the Partnership's historical consolidated statements of income:

	Three Months Ended September 30, 2013		
thousands	Partnership Historical	TEFR Interests	Combined
Revenues	$273,502	$—	$273,502
Equity income (loss), net	4,499	21	4,520
Net income (loss)	81,776	106	81,882
	Nine Months Ended September 30, 2013		
thousands	Partnership Historical	TEFR Interests	Combined
Revenues	$750,670	$—	$750,670
Equity income (loss), net	12,204	(260)	11,944
Net income (loss)	196,724	(21)	196,703

3. PARTNERSHIP DISTRIBUTIONS

The partnership agreement of Western Gas Partners, LP requires the Partnership to distribute all of its available cash (as defined in the partnership agreement) to unitholders of record on the applicable record date within 45 days of the end of each quarter. The board of directors of the general partner declared the following cash distributions to the Partnership's unitholders for the periods presented:

thousands except per-unit amounts Quarters Ended	Total Quarterly Distribution per Unit	Total Quarterly Cash Distribution	Date of Distribution
2013			
March 31	$0.540	$70,143	May 2013
June 30	0.560	79,315	August 2013
September 30	0.580	83,986	November 2013
2014			
March 31	$0.625	$98,749	May 2014
June 30	0.650	105,655	August 2014
September 30 [1]	0.675	111,609	November 2014

(1) On October 20, 2014, the board of directors of the Partnership's general partner declared a cash distribution to the Partnership's unitholders of $0.675 per unit, or $111.6 million in aggregate, including incentive distributions. The cash distribution is payable on November 13, 2014, to unitholders of record at the close of business on October 31, 2014.

4. EQUITY AND PARTNERS' CAPITAL

Equity offerings. The Partnership completed the following public offerings of its common units during 2014 and 2013:

thousands except unit and per-unit amounts	Common Units Issued	GP Units Issued [1]	Price Per Unit	Underwriting Discount and Other Offering Expenses	Net Proceeds
May 2013 equity offering [2]	7,015,000	143,163	$61.18	$13,203	$424,733
December 2013 equity offering [3]	4,800,000	97,959	61.51	9,447	291,827
Continuous Offering Program - 2013 [4]	685,735	13,996	60.84	965	41,603
Continuous Offering Program - 2014 [5]	1,133,384	23,132	73.48	1,726	83,257

(1) Represents general partner units issued to the general partner in exchange for the general partner's proportionate capital contribution to maintain its 2.0% general partner interest in the Partnership.

(2) Includes the issuance of 915,000 common units pursuant to the full exercise of the underwriters' over-allotment option granted in connection with the May 2013 equity offering.

(3) Includes the issuance of 300,000 common units on January 3, 2014, pursuant to the partial exercise of the underwriters' over-allotment option granted in connection with the December 2013 equity offering. Net proceeds from this partial exercise (including the general partner's proportionate capital contribution) were $18.1 million.

(4) Represents common and general partner units issued during the year ended December 31, 2013, pursuant to the Partnership's registration statement filed with the SEC in August 2012 authorizing the issuance of up to an aggregate of $125.0 million of common units (the "Continuous Offering Program"). Gross proceeds generated (including the general partner's proportionate capital contributions) during the year ended December 31, 2013, were $42.6 million. The price per unit in the table above represents an average price for all issuances under the Continuous Offering Program during 2013.

(5) Represents common and general partner units issued during the nine months ended September 30, 2014, under the Continuous Offering Program. Gross proceeds generated (including the general partner's proportionate capital contributions) were $85.0 million. The price per unit in the table above represents an average price for all issuances under the Continuous Offering Program during the nine months ended September 30, 2014. As of September 30, 2014, the Partnership had used all the capacity to issue common units under this registration statement.

Common and general partner units. The Partnership's common units are listed on the New York Stock Exchange under the symbol "WES."
The following table summarizes common and general partner units issued during the nine months ended September 30, 2014:

	Common Units	General Partner Units	Total
Balance at December 31, 2013	117,322,812	2,394,345	119,717,157
December 2013 equity offering	300,000	6,122	306,122
Long-Term Incentive Plan awards	5,418	112	5,530
TEFR Interests acquisition	308,490	6,296	314,786
Continuous Offering Program	1,133,384	23,132	1,156,516
Balance at September 30, 2014	119,070,104	2,430,007	121,500,111

Holdings of Partnership equity. As of September 30, 2014, WGP held 49,296,205 common units, representing a 40.6% limited partner interest in the Partnership, and, through its ownership of the general partner, WGP indirectly held 2,430,007 general partner units, representing a 2.0% general partner interest in the Partnership, and 100% of the Partnership’s IDRs. As of September 30, 2014, other subsidiaries of Anadarko held 757,619 common units, representing a 0.6% limited partner interest in the Partnership. As of September 30, 2014, the public held 69,016,280 common units, representing a 56.8% limited partner interest in the Partnership.

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4. EQUITY AND PARTNERS' CAPITAL (CONTINUED)

The Partnership's net income earned on and subsequent to the date of the acquisition of the Partnership assets (as defined in Note 1) is allocated to the general partner and the limited partners consistent with actual cash distributions, including incentive distributions allocable to the general partner. Undistributed earnings (net income in excess of distributions) or undistributed losses (available cash in excess of net income) are then allocated to the general partner and the limited partners in accordance with their respective ownership percentages.
Basic and diluted net income per common unit are calculated by dividing the limited partners' interest in net income by the weighted average number of common units outstanding during the period. The common units issued in connection with acquisitions and equity offerings are included on a weighted-average basis for periods during which they were outstanding.

5. TRANSACTIONS WITH AFFILIATES

Affiliate transactions. Revenues from affiliates include amounts earned by the Partnership from services provided to Anadarko as well as from the sale of residue, condensate and NGLs to Anadarko. In addition, the Partnership purchases natural gas from an affiliate of Anadarko pursuant to gas purchase agreements. Operating and maintenance expense includes amounts accrued for or paid to affiliates for the operation of the Partnership assets, whether in providing services to affiliates or to third parties, including field labor, measurement and analysis, and other disbursements. A portion of the Partnership's general and administrative expenses is paid by Anadarko, which results in affiliate transactions pursuant to the reimbursement provisions of the Partnership's omnibus agreement. Affiliate expenses do not bear a direct relationship to affiliate revenues, and third-party expenses do not bear a direct relationship to third-party revenues. See Note 1 for further information related to contributions of assets to the Partnership by Anadarko.

Cash management. Anadarko operates a cash management system whereby excess cash from most of its subsidiaries' separate bank accounts is generally swept to centralized accounts. Prior to the Partnership's acquisition of the Partnership assets, third-party sales and purchases related to such assets were received or paid in cash by Anadarko within its centralized cash management system. Anadarko charged or credited the Partnership interest at a variable rate on outstanding affiliate balances for the periods these balances remained outstanding. The outstanding affiliate balances were entirely settled through an adjustment to net investment by Anadarko in connection with the acquisition of the Partnership assets. Subsequent to the acquisition of Partnership assets from Anadarko, transactions related to such assets are cash-settled directly with third parties and with Anadarko affiliates, and affiliate-based interest expense on current intercompany balances is not charged. Chipeta cash settles its transactions directly with third parties and Anadarko, as well as with the other subsidiaries of the Partnership.

Note receivable from Anadarko. Concurrently with the closing of the Partnership's May 2008 initial public offering, the Partnership loaned $260.0 million to Anadarko in exchange for a 30-year note bearing interest at a fixed annual rate of 6.50%, payable quarterly. The fair value of the note receivable from Anadarko was $322.3 million and $296.7 million at September 30, 2014, and December 31, 2013, respectively. The fair value of the note reflects consideration of credit risk and any premium or discount for the differential between the stated interest rate and quarter-end market interest rate, based on quoted market prices of similar debt instruments. Accordingly, the fair value of the note receivable from Anadarko is measured using Level 2 inputs.

Commodity price swap agreements. The Partnership has commodity price swap agreements with Anadarko to mitigate exposure to commodity price volatility that would otherwise be present as a result of the purchase and sale of natural gas, condensate or NGLs. Notional volumes for each of the commodity price swap agreements are not specifically defined; instead, the commodity price swap agreements apply to the actual volume of natural gas, condensate and NGLs purchased and sold at the Granger, Hilight, Hugoton, Newcastle and MGR assets, as well as the DJ Basin complex, with various expiration dates through December 2016. In December 2013, the Partnership extended the commodity price swap agreements for the Hilight and Newcastle assets through December 2014. The commodity price swap agreements do not satisfy the definition of a derivative financial instrument and, therefore, are not required to be measured at fair value.

5. TRANSACTIONS WITH AFFILIATES (CONTINUED)

Below is a summary of the fixed price ranges on the Partnership's outstanding commodity price swap agreements as of September 30, 2014:

per barrel except natural gas	2014		2015		2016
Ethane	$18.36	– $30.53	$18.41	– $23.41	$23.11
Propane	40.38	– 53.78	47.08	– 52.99	52.90
Isobutane	61.24	– 75.13	62.09	– 74.02	73.89
Normal butane	53.89	– 66.83	54.62	– 65.04	64.93
Natural gasoline	71.85	– 90.89	72.88	– 81.82	81.68
Condensate	75.22	– 87.30	76.47	– 81.82	81.68
Natural gas (per MMBtu)	3.45	– 6.20	4.66	– 5.96	4.87

The following table summarizes realized gains and losses on commodity price swap agreements:

	Three Months Ended September 30,		Nine Months Ended September 30,	
thousands	2014	2013	2014	2013
Gains (losses) on commodity price swap agreements related to sales: (1)				
Natural gas sales	$3,179	$6,923	$1,525	$14,707
Natural gas liquids sales	22,737	27,541	66,746	83,049
Total	25,916	34,464	68,271	97,756
Losses on commodity price swap agreements related to purchases (2)	(19,533)	(23,902)	(38,081)	(66,613)
Net gains (losses) on commodity price swap agreements	$6,383	$10,562	$30,190	$31,143

(1) Reported in affiliate natural gas, natural gas liquids and condensate sales in the consolidated statements of income in the period in which the related sale is recorded.
(2) Reported in cost of product in the consolidated statements of income in the period in which the related purchase is recorded.

Gas gathering and processing agreements. The Partnership has significant gas gathering and processing arrangements with affiliates of Anadarko on a majority of its systems. The Partnership's gathering, transportation and treating throughput (excluding equity investment throughput and throughput measured in barrels) attributable to natural gas production owned or controlled by Anadarko was 47% and 53% for the three months ended September 30, 2014 and 2013, respectively, and 48% and 55% for the nine months ended September 30, 2014 and 2013, respectively. The Partnership's processing throughput (excluding equity investment throughput and throughput measured in barrels) attributable to natural gas production owned or controlled by Anadarko was 58% and 60% for the three months ended September 30, 2014 and 2013, respectively, and 58% and 59% for the nine months ended September 30, 2014 and 2013.

Equipment purchases and sales. The following table summarizes the Partnership's purchases from and sales to Anadarko of pipe and equipment:

	Nine Months Ended September 30,			
	2014	2013	2014	2013
thousands	Purchases		Sales	

Cash consideration	$16,143	$6,167	$—	$82
Net carrying value	9,745	2,039	—	34
Partners’ capital adjustment	$6,398	$4,128	$—	$48

5. TRANSACTIONS WITH AFFILIATES (CONTINUED)

WES LTIP. The general partner awards phantom units under the Western Gas Partners, LP 2008 Long-Term Incentive Plan ("WES LTIP") primarily to its independent directors and its Chief Executive Officer. The phantom units awarded to the independent directors vest one year from the grant date, while all other awards are subject to graded vesting over a three-year service period. Compensation expense is recognized over the vesting period and was $0.2 million and $0.5 million for the three and nine months ended September 30, 2014, respectively, and $0.1 million and $0.4 million for the three and nine months ended September 30, 2013, respectively.

WGP LTIP and Anadarko Incentive Plans. The Partnership's general and administrative expenses included $0.9 million and $2.7 million for the three and nine months ended September 30, 2014, respectively, and $0.8 million and $2.2 million for the three and nine months ended September 30, 2013, respectively, of equity-based compensation expense, allocated to the Partnership by Anadarko, for awards granted to the executive officers of the general partner and other employees under the Western Gas Equity Partners, LP 2012 Long-Term Incentive Plan ("WGP LTIP") and Anadarko Incentive Plans. For the nine months ended September 30, 2014, $2.5 million of allocated equity-based compensation expense is reflected as a contribution to partners' capital in the Partnership's consolidated statement of equity and partners' capital.

Summary of affiliate transactions. The following table summarizes affiliate transactions, which include revenue from affiliates, reimbursement of operating expenses and purchases of natural gas:

	Three Months Ended September 30,		Nine Months Ended September 30,	
thousands	2014	2013	2014	2013
Revenues (1)	$245,500	$213,125	$708,456	$591,010
Equity income, net (1)	19,063	4,520	41,322	11,944
Cost of product (1)	22,728	33,753	74,592	97,801
Operation and maintenance (2)	14,556	13,469	42,472	41,021
General and administrative (3)	6,566	5,867	19,859	17,325
Operating expenses	43,850	53,089	136,923	156,147
Interest income, net (4)	4,225	4,225	12,675	12,675
Distributions to unitholders (5)	60,794	44,378	169,001	121,493

(1) Represents amounts earned or incurred on and subsequent to the date of acquisition of the Partnership assets, as well as amounts earned or incurred by Anadarko on a historical basis related to the Partnership assets prior to the acquisition of such assets, recognized under gathering, treating or processing agreements, and purchase and sale agreements.

(2) Represents expenses incurred on and subsequent to the date of the acquisition of the Partnership assets, as well as expenses incurred by Anadarko on a historical basis related to the Partnership assets prior to the acquisition of such assets.

(3) Represents general and administrative expense incurred on and subsequent to the date of the Partnership's acquisition of the Partnership assets, as well as a management services fee for reimbursement of expenses incurred by Anadarko for periods prior to the acquisition of the Partnership assets by the Partnership. These amounts include equity-based compensation expense allocated to the Partnership by Anadarko (see WES LTIP and WGP LTIP and Anadarko Incentive Plans within this Note 5).

(4) Represents interest income recognized on the note receivable from Anadarko.

(5) Represents distributions paid under the partnership agreement (see Note 3 and Note 4).

Concentration of credit risk. Anadarko was the only customer from whom revenues exceeded 10% of the Partnership's consolidated revenues for all periods presented in the consolidated statements of income.

6. PROPERTY, PLANT AND EQUIPMENT

A summary of the historical cost of the Partnership's property, plant and equipment is as follows:

thousands	Estimated Useful Life	September 30, 2014	December 31, 2013
Land	n/a	$2,584	$2,584
Gathering systems	3 to 47 years	4,244,640	3,673,008
Pipelines and equipment	15 to 45 years	145,851	146,008
Assets under construction	n/a	345,799	405,633
Other	3 to 40 years	15,405	11,867
Total property, plant and equipment		4,754,279	4,239,100
Accumulated depreciation		986,692	855,845
Net property, plant and equipment		$3,767,587	$3,383,255

The cost of property classified as "Assets under construction" is excluded from capitalized costs being depreciated. These amounts represent property that is not yet suitable to be placed into productive service as of the respective balance sheet date.

At December 31, 2013, other long-term assets includes $4.6 million of unguaranteed residual value related to the capital lease component of a processing agreement assumed in connection with the acquisition of the Granger straddle plant as a part of the Mountain Gas Resources, LLC acquisition in January 2012. This agreement, in which the Partnership was the lessor, was replaced effective April 1, 2014, with a gas conditioning agreement that does not satisfy criteria required for lease classification. As such, during the second quarter of 2014, the Partnership reclassified the $4.6 million capital lease asset from other long-term assets to property, plant and equipment and commenced depreciation.

During the three and nine months ended September 30, 2014, the Partnership recognized impairments of $0.4 million and $0.7 million, respectively, related to the cancellation of various capital projects by the third-party operator of the Non-Operated Marcellus Interest. During the three months ended September 30, 2014, the Partnership also recognized an impairment of $0.5 million related to a compressor no longer in service at the Hilight system. During the first quarter of 2014, the Partnership recognized a $1.2 million impairment primarily related to a non-operational plant in the Powder River Basin that was impaired to its estimated fair value of $2.4 million, using Level 3 fair-value inputs.

7. COMPONENTS OF WORKING CAPITAL

A summary of other current assets is as follows:

thousands	September 30, 2014	December 31, 2013
Natural gas liquids inventory	$2,022	$2,584
Natural gas imbalance receivables	1,181	3,605
Prepaid insurance	2,521	2,123
Other	1,049	1,710
Total other current assets	$6,773	$10,022

7. COMPONENTS OF WORKING CAPITAL (CONTINUED)

A summary of accrued liabilities is as follows:

thousands	September 30, 2014	December 31, 2013
Accrued capital expenditures	$92,559	$94,750
Accrued plant purchases	30,563	21,396
Accrued interest expense	28,525	18,119
Short-term asset retirement obligations	483	1,966
Short-term remediation and reclamation obligations	562	562
Other	186	218
Total accrued liabilities	$152,878	$137,011

8. DEBT AND INTEREST EXPENSE

At September 30, 2014, the Partnership's debt consisted of 5.375% Senior Notes due 2021 (the "2021 Notes"), 4.000% Senior Notes due 2022 (the "2022 Notes"), 2.600% Senior Notes due 2018 (the "2018 Notes"), 5.450% Senior Notes due 2044 (the "2044 Notes"), and the senior unsecured revolving credit facility ("RCF"). The two tranches of the 2022 Notes, issued in June and October 2012, were issued under the same indenture and are considered a single class of securities. The two tranches of the 2018 Notes, issued in August 2013 and March 2014, were issued under the same indenture and are considered a single class of securities.
The following table presents the Partnership's outstanding debt as of September 30, 2014, and December 31, 2013:

	September 30, 2014			December 31, 2013		
thousands	Principal	Carrying Value	Fair Value [1]	Principal	Carrying Value	Fair Value [1]
5.375% Senior Notes due 2021	$500,000	$495,576	$557,828	$500,000	$495,173	$533,615
4.000% Senior Notes due 2022	670,000	673,017	690,811	670,000	673,278	641,237
Revolving credit facility	170,000	170,000	170,000	—	—	—
2.600% Senior Notes due 2018	350,000	350,506	355,311	250,000	249,718	247,988
5.450% Senior Notes due 2044	400,000	393,815	437,573	—	—	—
Total debt outstanding	$2,090,000	$2,082,914	$2,211,523	$1,420,000	$1,418,169	$1,422,840

(1) Fair value is measured using Level 2 inputs.

Debt activity. The following table presents the debt activity of the Partnership for the nine months ended September 30, 2014:

thousands	Carrying Value
Balance at December 31, 2013	$1,418,169
Revolving credit facility borrowings	650,000
Issuance of 5.450% Senior Notes due 2044	400,000
Issuance of 2.600% Senior Notes due 2018	100,000
Repayments of revolving credit facility	(480,000)
Other	(5,255)
Balance at September 30, 2014	$2,082,914

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8. DEBT AND INTEREST EXPENSE (CONTINUED)

Senior Notes. The 2044 Notes issued in March 2014 were offered at a price to the public of 98.443% of the face amount. Including the effects of the issuance and underwriting discounts, the effective interest rate of the 2044 Notes is 5.633%. Interest is paid semi-annually on April 1 and October 1 of each year. Proceeds (net of underwriting discount of $3.5 million, original issue discount and debt issuance costs) were used to repay amounts then outstanding under the Partnership's RCF and for general partnership purposes.

The 2018 Notes issued in March 2014 were offered at a price to the public of 100.857% of the face amount. Including the effects of the issuance premium for the March 2014 offering, the issuance discount for the August 2013 offering of 2018 Notes and underwriting discounts, the effective interest rate of the 2018 Notes is 2.743%. Interest is paid semi-annually on February 15 and August 15 of each year. Proceeds (net of underwriting discount of $0.6 million, original issue premium and debt issuance costs) were used to repay amounts then outstanding under the Partnership's RCF and for general partnership purposes.

At September 30, 2014, the Partnership was in compliance with all covenants under the indentures governing the 2021 Notes, 2022 Notes, 2018 Notes, and 2044 Notes.

Revolving credit facility. In February 2014, the Partnership entered into an amended and restated $1.2 billion senior unsecured RCF, which is expandable to a maximum of $1.5 billion, replacing an $800.0 million credit facility, which was originally entered into in March 2011. Subsequent to February 2014, the Partnership borrowed $350.0 million under the RCF to fund the acquisition of the TEFR Interests (see Note 2). The RCF matures in February 2019 and bears interest at London Interbank Offered Rate ("LIBOR"), plus applicable margins ranging from 0.975% to 1.45%, or an alternate base rate equal to the greatest of (a) the Prime Rate, (b) the Federal Funds Effective Rate plus 0.5%, or (c) LIBOR plus 1%, in each case plus applicable margins currently ranging from zero to 0.45%, based upon the Partnership's senior unsecured debt rating. The interest rate on the RCF was 1.46% at September 30, 2014. At December 31, 2013, the interest rate on the previous credit facility was 1.67%. The Partnership is required to pay a quarterly facility fee currently ranging from 0.15% to 0.30% of the commitment amount (whether used or unused), based upon the Partnership's senior unsecured debt rating. The facility fee rate was 0.20% and 0.25% at September 30, 2014, and December 31, 2013, respectively.

As of September 30, 2014, the Partnership had $170.0 million of outstanding borrowings, $12.8 million in outstanding letters of credit and $1.0 billion available for borrowing under the RCF. At September 30, 2014, the Partnership was in compliance with all covenants under the RCF. See Note 10.

The 2021 Notes, 2022 Notes, 2018 Notes, 2044 Notes and obligations under the RCF are recourse to the Partnership's general partner. The Partnership's general partner is indemnified by a wholly owned subsidiary of Anadarko, Western Gas Resources, Inc. ("WGRI"), against any claims made against the general partner under the 2022 Notes, 2021 Notes, and/or the RCF.

In connection with the acquisitions of the Non-Operated Marcellus Interest, the Anadarko-Operated Marcellus Interest, and the TEFR Interests, the Partnership's general partner and other wholly owned subsidiaries of Anadarko entered into indemnification agreements, whereby such subsidiaries agreed to indemnify the Partnership's general partner for any recourse liability it may have for RCF borrowings, or other debt financing, attributable to the acquisitions of the Non-Operated Marcellus Interest, the Anadarko-Operated Marcellus Interest, and the TEFR Interests. These indemnification agreements apply to the 2044 Notes, 2018 Notes, and/or RCF borrowings outstanding related to the aforementioned acquisitions.

The Partnership's general partner, the other indemnifying subsidiaries of Anadarko and WGRI also amended and restated the indemnity agreements between them to (i) conform language among all the indemnification agreements and (ii) reduce the amount for which WGRI would indemnify the Partnership's general partner by an amount equal to any amounts payable to the Partnership's general partner under the indemnification agreements related to the acquisitions of the Non-Operated Marcellus Interest, the Anadarko-Operated Marcellus Interest, and the TEFR Interests.

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8. DEBT AND INTEREST EXPENSE (CONTINUED)

Interest expense. The following table summarizes the amounts included in interest expense:

	Three Months Ended September 30,		Nine Months Ended September 30,	
thousands	2014	2013	2014	2013
Interest expense on long-term debt	$21,671	$14,994	$59,251	$43,783
Amortization of debt issuance costs and commitment fees	1,107	1,135	3,799	3,252
Capitalized interest	(1,900)	(3,111)	(7,347)	(9,552)
Interest expense	$20,878	$13,018	$55,703	$37,483

9. COMMITMENTS AND CONTINGENCIES

Litigation and legal proceedings. In March 2011, DCP Midstream, LP ("DCP") filed a lawsuit against Anadarko and others, including a Partnership subsidiary, Kerr-McGee Gathering, LLC, in Weld County District Court (the "Court") in Colorado, alleging that Anadarko diverted gas from DCP's gathering and processing facilities in breach of certain dedication agreements. In addition to various claims against Anadarko, DCP is claiming unjust enrichment and other damages against Kerr-McGee Gathering, LLC, the entity that holds the Wattenberg assets (located in the DJ Basin complex). Anadarko countersued DCP asserting that DCP has not properly allocated values and charges to Anadarko for the gas that DCP gathers and/or processes, and seeks a judgment that DCP has no valid gathering or processing rights to much of the gas production it is claiming, in addition to other claims.
In July 2011, the Court denied the defendants' motion to dismiss without ruling on the merits. In August 2014, the judge scheduled a jury trial for July 2015. In preparation for trial, the parties amended their pleadings in October 2014 and are engaged in discovery and motion practice. Management does not believe the outcome of this proceeding will have a material effect on the Partnership's financial condition, results of operations or cash flows. The Partnership intends to vigorously defend this litigation. Furthermore, without regard to the merit of DCP's claims, management believes that the Partnership has adequate contractual indemnities covering the claims against it in this lawsuit.
In addition, from time to time, the Partnership is involved in legal, tax, regulatory and other proceedings in various forums regarding performance, contracts and other matters that arise in the ordinary course of business. Management is not aware of any such proceeding for which a final disposition could have a material adverse effect on the Partnership's financial condition, results of operations or cash flows.

Other commitments. The Partnership has short-term payment obligations, or commitments, related to its capital spending programs, as well as those of its unconsolidated affiliates. As of September 30, 2014, the Partnership had unconditional payment obligations for services to be rendered or products to be delivered in connection with its capital projects of $70.5 million, the majority of which is expected to be paid in the next twelve months. These commitments relate primarily to projects at the DJ Basin complex, which include the continued construction of a second train and compressor expansions.

Lease commitments. Anadarko, on behalf of the Partnership, has entered into lease agreements for corporate offices, shared field offices and a warehouse supporting the Partnership's operations. The leases for the corporate offices and shared field offices extend through 2017 and 2018, respectively, and the lease for the warehouse extends through February 2015 and includes an early termination clause.
Rent expense associated with the office, warehouse and equipment leases was $0.7 million and $2.2 million for the three and nine months ended September 30, 2014, respectively, and $0.6 million and $2.0 million for the three and nine months ended September 30, 2013, respectively.

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10. SUBSEQUENT EVENT

On October 28, 2014, the Partnership announced its entry into an Agreement and Plan of Merger by and among the Partnership, Maguire Midstream, LLC, Nuevo Midstream, LLC (“Nuevo”) and the other parties thereto, pursuant to which the Partnership will acquire Nuevo for $1.5 billion in cash, subject to adjustment. Nuevo’s assets currently include a cryogenic processing complex, gas gathering system and related facilities and equipment. The assets serve production from Reeves, Loving and Culberson Counties, Texas and Eddy and Lea Counties, New Mexico.

The Partnership expects to fund this acquisition with (i) cash on hand, (ii) borrowings under the RCF and (iii) the issuance of $750.0 million of Class C units to Anadarko. The Class C units will receive distributions in the form of additional Class C units until the end of 2017 (unless earlier converted), and will be disregarded with respect to calculating the Partnership’s cash distributions until they are converted to common units. The Class C units will convert into common units on a one-for-one basis on December 31, 2017, unless the Partnership elects to convert such units earlier or Anadarko extends the conversion date.

Pursuant to the terms of a joint venture agreement between Anadarko and a third party, the Partnership has offered the third party the right to acquire a 50% interest in Nuevo. The third party is required to respond to the Partnership’s offer within thirty days of receiving notice, and will have an additional thirty days to fund its share of the purchase price if it accepts the offer. The Partnership is prepared to purchase 100% of Nuevo if the third party does not participate. The Partnership expects the acquisition will close in the fourth quarter of 2014 subject to regulatory approval and customary closing conditions.

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

For purposes of this report, "we," "us," "our," the "Partnership," or "Western Gas Partners" refers to Western Gas Partners, LP and its subsidiaries. Our general partner, Western Gas Holdings, LLC (the "general partner" or "GP"), is owned by Western Gas Equity Partners, LP ("WGP"), a Delaware master limited partnership formed by Anadarko Petroleum Corporation. Western Gas Equity Holdings, LLC is WGP's general partner and is a wholly owned subsidiary of Anadarko Petroleum Corporation. "Anadarko" refers to Anadarko Petroleum Corporation and its subsidiaries, excluding the Partnership and our general partner, and "affiliates" refers to subsidiaries of Anadarko, excluding the Partnership, and includes equity interests in Fort Union Gas Gathering, LLC ("Fort Union"), White Cliffs Pipeline, LLC ("White Cliffs"), Rendezvous Gas Services, LLC ("Rendezvous"), Enterprise EF78, LLC (the "Mont Belvieu JV"), Texas Express Pipeline LLC ("TEP"), Texas Express Gathering LLC ("TEG") and Front Range Pipeline LLC ("FRP"). The interests in TEP, TEG and FRP are referred to collectively as the "TEFR Interests." "Equity investment throughput" refers to our 14.81% share of average Fort Union throughput and our 22% share of average Rendezvous throughput, but excludes throughput measured in barrels consisting of our 10% share of average White Cliffs throughput, our 25% share of average Mont Belvieu JV throughput, our 20% share of average TEP and TEG throughput and our 33.33% share of average FRP throughput. The "DJ Basin complex" refers to the Platte Valley system, Wattenberg system, and Lancaster plant, all of which were combined into a single complex in the first quarter of 2014.
The following discussion analyzes our financial condition and results of operations and should be read in conjunction with the consolidated financial statements and notes to consolidated financial statements, which are included under Part I, Item 1 of this quarterly report, as well as our historical consolidated financial statements, and the notes thereto, which are included in Part II, Item 8 of our 2013 Form 10-K as filed with the Securities and Exchange Commission, or "SEC," on February 28, 2014, certain sections of which were recast to reflect the results of the TEFR Interests in our Current Report on Form 8-K, as filed with the SEC on August 27, 2014, and our other public filings and press releases.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

We have made in this report, and may from time to time otherwise make in other public filings, press releases and discussions by management, forward-looking statements concerning our operations, economic performance and financial condition. These statements can be identified by the use of forward-looking terminology including "may," "will," "believe," "expect," "anticipate," "estimate," "continue," or other similar words. These statements discuss future expectations, contain projections of results of operations or financial condition or include other "forward-looking" information. Although we believe that the expectations reflected in such forward-looking statements are reasonable, we can give no assurance that such expectations will be realized.

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

- our ability to pay distributions to our unitholders;
- our and Anadarko's assumptions about the energy market;
- future throughput, including Anadarko's production, which is gathered or processed by or transported through our assets;
- operating results;
- competitive conditions;

- technology;
- availability of capital resources to fund acquisitions, capital expenditures and other contractual obligations, and our ability to access those resources from Anadarko or through the debt or equity capital markets;
- supply of, demand for, and the price of, oil, natural gas, NGLs and related products or services;

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- weather;
- inflation;
- availability of goods and services;
- general economic conditions, either internationally or domestically or in the jurisdictions in which we are doing business;
- changes in regulations at the federal, state and local level or the inability to timely obtain or maintain permits that could affect our and our customers’ activities; environmental risks; regulations by the Federal Energy Regulatory Commission (“FERC”); and liability under federal and state laws and regulations;
- legislative or regulatory changes, including changes impacting Anadarko and other producers that would limit hydraulic fracturing or other oil and gas operations, and changes affecting our status as a partnership for federal income tax purposes;
- changes in the financial or operational condition of Anadarko;
- changes in Anadarko’s capital program, strategy or desired areas of focus;
- our commitments to capital projects;
- ability to use our revolving credit facility (“RCF”);
- creditworthiness of Anadarko or our other counterparties, including financial institutions, operating partners, and other parties;
- our ability to repay debt;
- our ability to mitigate commodity price risks inherent in our percent-of-proceeds and keep-whole contracts;
- conflicts of interest among us, our general partner, WGP and its general partner, and affiliates, including Anadarko;
- our ability to maintain and/or obtain rights to operate our assets on land owned by third parties;
- our ability to acquire assets on acceptable terms;
- non-payment or non-performance of Anadarko or other significant customers, including under our gathering, processing and transportation agreements and our $260.0 million note receivable from Anadarko;
- timing, amount and terms of future issuances of equity and debt securities; and
- other factors discussed below, in “Risk Factors” included in our 2013 Form 10-K, in “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates,” in our quarterly reports on Form 10-Q and elsewhere in our other public filings and press releases.

The risk factors and other factors noted throughout or incorporated by reference in this report could cause our actual results to differ materially from those contained in any forward-looking statement. We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

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EXECUTIVE SUMMARY

We are a growth-oriented Delaware master limited partnership formed by Anadarko to own, operate, acquire and develop midstream energy assets. We currently own or have investments in assets located in the Rocky Mountains (Colorado, Utah and Wyoming), the Mid-Continent (Kansas and Oklahoma), north-central Pennsylvania and Texas, and are engaged in the business of gathering, processing, compressing, treating and transporting natural gas, condensate, NGLs and crude oil for Anadarko, as well as for third-party producers and customers. As of September 30, 2014, our assets and investments accounted for under the equity method consisted of the following:

	Owned and Operated	Operated Interests	Non-Operated Interests	Equity Interests
Natural gas gathering systems	13	1	5	2
NGL gathering systems	—	—	—	2
Natural gas treating facilities	8	—	—	1
Natural gas processing facilities	9	3	—	2
NGL pipelines	3	—	—	2
Natural gas pipelines	3	—	—	—
Oil pipeline	—	—	—	1

See also Note 10—Subsequent Event in the Notes to Consolidated Financial Statements under Item 1 of this Form 10-Q.

Significant financial and operational highlights during the first nine months of 2014 included the following:

- We issued 1,133,384 common units to the public under our Continuous Offering Program (as defined below), generating net proceeds of $83.3 million, including the general partner's proportionate capital contribution to maintain its 2.0% general partner interest. Net proceeds were used for general partnership purposes, including funding capital expenditures. See Equity Offerings below.

- We completed construction and commenced operations in April 2014 of the 300 MMcf/d Train I at the Lancaster processing plant (located in the DJ Basin complex) in Northeast Colorado, and are constructing the 300 MMcf/d Train II at the same plant with operations expected to commence in the second quarter of 2015.

- We issued $400.0 million aggregate principal amount of 5.450% Senior Notes due 2044 and an additional $100.0 million aggregate principal amount of 2.600% Senior Notes due 2018. Net proceeds were used to repay amounts then outstanding under our RCF. See Liquidity and Capital Resources within this Item 2 for additional information.

- We completed the acquisition of Anadarko's 20% interests in TEG and TEP, and its 33.33% interest in FRP. See Acquisitions below.

- We entered into an amended and restated $1.2 billion (expandable to $1.5 billion) senior unsecured RCF replacing our $800.0 million credit facility. See Liquidity and Capital Resources within this Item 2 for additional information.

- We raised our distribution to $0.675 per unit for the third quarter of 2014, representing a 4% increase over the distribution for the second quarter of 2014 and a 16% increase over the distribution for the third quarter of 2013.

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- Throughput attributable to Western Gas Partners, LP totaled 3,459 MMcf/d and 3,476 MMcf/d for the three and nine months ended September 30, 2014, respectively, representing a 5% and 12% increase, respectively, compared to the same periods in 2013.

- Adjusted gross margin attributable to Western Gas Partners, LP for natural gas assets (as defined under the caption Key Performance Metrics within this Item 2) averaged $0.67 per Mcf and $0.64 per Mcf for the three and nine months ended September 30, 2014, respectively, representing a 16% and 14% increase, respectively, compared to the same periods in 2013.

- Adjusted gross margin for crude/NGL assets (as defined under the caption Key Performance Metrics within this Item 2) averaged $1.53 per Bbl and $1.71 per Bbl for the three and nine months ended September 30, 2014, respectively, representing a 10% and 20% increase, respectively, compared to the same periods in 2013.

ACQUISITIONS

Acquisitions. The following table presents our acquisitions during 2014 and 2013, and identifies the funding sources for such acquisitions.

thousands except unit and percent amounts	Acquisition Date	Percentage Acquired		Borrowings	Cash On Hand	Common Units Issued
Non-Operated Marcellus Interest (1)	03/01/2013	33.75	%	$250,000	$215,500	449,129
Anadarko-Operated Marcellus Interest (2)	03/08/2013	33.75	%	133,500	—	—
Mont Belvieu JV (3)	06/05/2013	25	%	—	78,129	—
OTTCO (4)	09/03/2013	100	%	27,500	—	—
TEFR Interests (5)	03/03/2014	Various (5)		350,000	6,250	308,490

(1) We acquired Anadarko’s 33.75% interest (non-operated) in the Liberty and Rome gas gathering systems, serving production from the Marcellus shale in north-central Pennsylvania. The interest acquired is referred to as the “Non-Operated Marcellus Interest.” In connection with the issuance of the common units, our general partner purchased 9,166 general partner units for consideration of $0.5 million to maintain its 2.0% general partner interest in us.

(2) We acquired a 33.75% interest in each of the Larry’s Creek, Seely and Warrensville gas gathering systems, which are operated by Anadarko and serve production from the Marcellus shale in north-central Pennsylvania, from a third party. The interest acquired is referred to as the “Anadarko-Operated Marcellus Interest.” During the third quarter of 2013, we recorded a $1.1 million decrease in the assets acquired and liabilities assumed in the acquisition, representing the final purchase price allocation.

(3) We acquired a 25% interest in the Mont Belvieu JV, an entity formed to design, construct, and own two fractionation trains located in Mont Belvieu, Texas, from a third party. The interest acquired is accounted for under the equity method of accounting.

(4) We acquired Overland Trail Transmission, LLC (“OTTCO”), a Delaware limited liability company, from a third party. OTTCO owns and operates an intrastate pipeline that connects our Red Desert and Granger complexes in southwestern Wyoming.

(5) We acquired a 20% interest in each of TEG and TEP and a 33.33% interest in FRP from Anadarko. These assets gather and transport NGLs primarily from the Anadarko and Denver-Julesburg Basins. TEG consists of two NGL gathering systems that link natural gas processing plants to TEP. TEP is an NGL pipeline that originates in Skellytown, Texas and extends approximately 580 miles to Mont Belvieu, Texas. FRP is a 435 mile NGL pipeline that extends from Weld County, Colorado to Skellytown, Texas. The interests in these entities are accounted for under the equity method of accounting. In connection with the issuance of the common units, our general partner purchased 6,296 general partner units for consideration of $0.4 million to maintain its 2.0% general partner interest

in us. See Note 2—Acquisitions in the Notes to Consolidated Financial Statements under Item 1 of this Form 10-Q.

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Presentation of Partnership assets. The “Partnership assets” refer collectively to the assets owned and interests accounted for under the equity method by us as of September 30, 2014. Because Anadarko controls us through its ownership and control of WGP, which owns our general partner, each of our acquisitions of Partnership assets from Anadarko has been considered a transfer of net assets between entities under common control. As such, the Partnership assets we acquired from Anadarko were initially recorded at Anadarko’s historic carrying value, which did not correlate to the total acquisition price paid by us (see Note 2—Acquisitions in the Notes to Consolidated Financial Statements under Item 1 of this Form 10-Q). Further, after an acquisition of the Partnership assets from Anadarko, we may be required to recast our financial statements to include the activities of the Partnership assets as of the date of common control. The historical financial statements previously filed with the SEC have been recast in this Form 10-Q to include the results attributable to the TEFR Interests for all periods presented. The consolidated financial statements for periods prior to our acquisition of the Partnership assets from Anadarko, including the TEFR Interests, have been prepared from Anadarko’s historical cost-basis accounts and may not necessarily be indicative of the actual results of operations that would have occurred if we had owned the Partnership assets during the periods reported.

EQUITY OFFERINGS

Equity offerings. We completed the following public equity offerings during 2014 and 2013:

thousands except unit and per-unit amounts	Common Units Issued	GP Units Issued (1)	Price Per Unit	Underwriting Discount and Other Offering Expenses	Net Proceeds
May 2013 equity offering (2)	7,015,000	143,163	$61.18	$13,203	$424,733
December 2013 equity offering (3)	4,800,000	97,959	61.51	9,447	291,827
Continuous Offering Program - 2013 (4)	685,735	13,996	60.84	965	41,603
Continuous Offering Program - 2014 (5)	1,133,384	23,132	73.48	1,726	83,257

(1) Represents general partner units issued to the general partner in exchange for the general partner’s proportionate capital contribution to maintain its 2.0% general partner interest in us.

(2) Includes the issuance of 915,000 common units pursuant to the full exercise of the underwriters’ over-allotment option granted in connection with the May 2013 equity offering.

(3) Includes the issuance of 300,000 common units on January 3, 2014, pursuant to the partial exercise of the underwriters’ over-allotment option granted in connection with the December 2013 equity offering. Net proceeds from this partial exercise (including the general partner’s proportionate capital contribution) were $18.1 million.

(4) Represents common and general partner units issued during the year ended December 31, 2013, pursuant to our registration statement filed with the SEC in August 2012 authorizing the issuance of up to an aggregate of $125.0 million of common units (the “Continuous Offering Program”). Gross proceeds generated (including our general partner’s proportionate capital contributions) were $42.6 million. The price per unit in the table above represents an average price for all issuances under the Continuous Offering Program during 2013.

(5) Represents common and general partner units issued during the nine months ended September 30, 2014, under the Continuous Offering Program. Gross proceeds generated (including the general partner’s proportionate capital contributions) were $85.0 million. The price per unit in the table above represents an average price for all issuances under the Continuous Offering Program during the nine months ended September 30, 2014. As of September 30, 2014, we had used all the capacity to issue units under this registration statement.

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RESULTS OF OPERATIONS

OPERATING RESULTS

The following tables and discussion present a summary of our results of operations:

	Three Months Ended September 30,		Nine Months Ended September 30,	
thousands	2014	2013	2014	2013
Gathering, processing and transportation of natural gas and natural gas liquids	$168,356	$130,781	$471,055	$343,471
Natural gas, natural gas liquids and condensate sales	150,094	141,326	453,186	402,616
Other, net	8,015	1,395	11,625	4,583
Total revenues (1)	326,465	273,502	935,866	750,670
Equity income, net	19,063	4,520	41,322	11,944
Total operating expenses (1)	222,154	187,813	638,523	538,523
Operating income	123,374	90,209	338,665	224,091
Interest income, net – affiliates	4,225	4,225	12,675	12,675
Interest expense	(20,878)	(13,018)	(55,703)	(37,483)
Other income (expense), net	97	439	788	1,612
Income before income taxes	106,818	81,855	296,425	200,895
Income tax (benefit) expense	278	(27)	276	4,192
Net income	106,540	81,882	296,149	196,703
Net income attributable to noncontrolling interest	3,863	3,376	11,005	7,467
Net income attributable to Western Gas Partners, LP	$102,677	$78,506	$285,144	$189,236
Key performance metrics (2)				
Adjusted gross margin attributable to Western Gas Partners, LP	$233,297	$179,379	$659,275	$483,823
Adjusted EBITDA attributable to Western Gas Partners, LP	167,297	125,176	475,594	328,750
Distributable cash flow	136,722	105,883	392,996	274,795

(1) Revenues include amounts earned from services provided to our affiliates, as well as from the sale of residue, condensate and NGLs to our affiliates. Operating expenses include amounts charged by our affiliates for services as well as reimbursement of amounts paid by affiliates to third parties on our behalf. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Item 1 of this Form 10-Q.

(2) Adjusted gross margin attributable to Western Gas Partners, LP, Adjusted EBITDA attributable to Western Gas Partners, LP and Distributable cash flow are defined and reconciled to their most directly comparable financial measures calculated and presented in accordance with Generally Accepted Accounting Principles (“GAAP”) under the caption Key Performance Metrics within this Item 2.

For purposes of the following discussion, any increases or decreases “for the three months ended September 30, 2014” refer to the comparison of the three months ended September 30, 2014, to the three months ended September 30, 2013; any increases or decreases “for the nine months ended September 30, 2014” refer to the comparison of the nine months ended September 30, 2014, to the nine months ended September 30, 2013; and any increases or decreases “for the three and nine months ended September 30, 2014” refer to both the comparisons for the three and nine months ended September 30, 2014.

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Throughput

MMcf/d (except throughput measured in barrels)	Three Months Ended September 30, 2014	2013	Inc/ (Dec)	Nine Months Ended September 30, 2014	2013	Inc/ (Dec)
Throughput for natural gas assets						
Gathering, treating and transportation [1]	1,513	1,439	5 %	1,571	1,354	16 %
Processing [1]	1,936	1,802	7 %	1,903	1,712	11 %
Equity investment [2]	175	221	(21)%	171	211	(19)%
Total throughput for natural gas assets	3,624	3,462	5 %	3,645	3,277	11 %
Throughput attributable to noncontrolling interest for natural gas assets	165	177	(7)%	169	166	2 %
Total throughput attributable to Western Gas Partners, LP for natural gas assets [3]	3,459	3,285	5 %	3,476	3,111	12 %
Total throughput (MBbls/d) for crude/NGL assets [4]	138	31	NM	111	28	NM

NM-Not meaningful

(1) The combination of our Wattenberg and Platte Valley systems in the first quarter of 2014 into the entity now referred to as the "DJ Basin complex" (also includes the Lancaster plant) resulted in the following: (i) the Wattenberg system volumes previously reported as "Gathering, treating and transportation" are now reported as "Processing" for all periods presented, and (ii) beginning with the first quarter of 2014, volumes both gathered and processed by the two systems are no longer separately reported.

(2) Represents our 14.81% share of average Fort Union and our 22% share of average Rendezvous throughput. Excludes equity investment throughput measured in barrels (captured in "Total throughput (MBbls/d) for crude/NGL assets" as noted below).

(3) Includes affiliate, third-party and equity investment throughput (as equity investment throughput is defined in the above footnote), excluding the noncontrolling interest owner's proportionate share of throughput.

(4) Represents total throughput measured in barrels consisting of throughput from our Chipeta NGL pipeline, our 10% share of average White Cliffs throughput, our 25% share of average Mont Belvieu JV throughput, our 20% share of average TEG and TEP throughput and our 33.33% share of average FRP throughput.

Gathering, treating and transportation throughput increased by 74 MMcf/d for the three months ended September 30, 2014, due to increased throughput from the Non-Operated Marcellus Interest as a result of additional well connections, partially offset by decreased throughput at Bison due to a period of reduced flow resulting from planned maintenance activity. Gathering, treating and transportation throughput increased by 217 MMcf/d for the nine months ended September 30, 2014, due to increased throughput from the Non-Operated Marcellus Interest as a result of additional well connections and additional throughput from the Anadarko-Operated Marcellus Interest after the March 2013 acquisition, partially offset by throughput decreases at Bison due to the aforementioned maintenance activity and decreases at the Pinnacle and Dew systems resulting from natural production declines in those areas.

Processing throughput increased by 134 MMcf/d for the three months ended September 30, 2014, primarily due to the start-up of the Brasada facility in June 2013, increased volumes processed at a plant included in the MGR acquisition (the "Granger straddle plant") and the start-up of the Lancaster plant in April 2014, partially offset by throughput decreases at Chipeta and the Red Desert complex. Processing throughput increased by 191 MMcf/d for the nine months ended September 30, 2014, primarily due to the start-up of the Brasada facility in June 2013, increased volumes processed at the Granger straddle plant and throughput growth at Chipeta, partially offset by throughput declines at the Granger complex.

Equity investment throughput decreased by 46 MMcf/d and 40 MMcf/d for the three and nine months ended September 30, 2014, respectively, primarily due to lower throughput at the Fort Union system due to production declines in the area and volumes being diverted to the third-party Bison pipeline.

Throughput for crude/NGL assets measured in barrels increased by 107 MBbls/d and 83 MBbls/d for the three and nine months ended September 30, 2014, respectively, due to the start-up of (i) the Mont Belvieu JV fractionation trains in the fourth quarter 2013, (ii) TEP and TEG in fourth quarter 2013, and (iii) FRP in March 2014.

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Gathering, Processing and Transportation of Natural Gas and Natural Gas Liquids

thousands except percentages	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Inc/ (Dec)	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013	Inc/ (Dec)
Gathering, processing and transportation of natural gas and natural gas liquids	$168,356	$130,781	29 %	$471,055	$343,471	37 %

Revenues from gathering, processing and transportation of natural gas and natural gas liquids increased by $37.6 million and $127.6 million for the three and nine months ended September 30, 2014, respectively, primarily due to increases of (i) $20.5 million and $44.5 million, respectively, resulting from increased throughput at the DJ Basin complex and the start-up of the Lancaster plant in April 2014, (ii) $5.7 million and $27.3 million, respectively, due to the start-up of the Brasada facility in June 2013, (iii) $5.7 million and $25.5 million, respectively, at the Non-Operated Marcellus Interest due to higher throughput and average gathering rate, (iv) $2.7 million and $3.4 million, respectively, due to new third-party gathering agreements at Hilight, and (v) $1.7 million and $11.7 million, respectively, due to increased throughput at Chipeta's Train III, as well as the retroactive application of a fee increase in the third quarter of 2014 that was applicable upon Train III being placed into service. In addition, higher throughput at the Anadarko-Operated Marcellus Interest, acquired in March 2013, contributed $13.0 million to the increase for the nine months ended September 30, 2014.

Natural Gas, Natural Gas Liquids and Condensate Sales

thousands except percentages and per-unit amounts	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Inc/ (Dec)	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013	Inc/ (Dec)
Natural gas sales	$41,386	$30,034	38 %	$109,349	$85,025	29 %
Natural gas liquids sales	97,972	104,535	(6)%	312,426	294,133	6 %
Drip condensate sales	10,736	6,757	59 %	31,411	23,458	34 %
Total	$150,094	$141,326	6 %	$453,186	$402,616	13 %
Average price per unit:						
Natural gas (per Mcf)	$3.96	$5.06	(22)%	$4.17	$4.53	(8)%
Natural gas liquids (per Bbl)	42.17	48.09	(12)%	45.02	47.65	(6)%
Drip condensate (per Bbl)	79.93	76.69	4 %	82.19	76.18	8 %

For the three and nine months ended September 30, 2014 and 2013, average natural gas, NGL and drip condensate prices include the effects of commodity price swap agreements attributable to sales for the DJ Basin complex, and the Granger, Hilight, Hugoton, Newcastle, and MGR assets. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Item 1 of this Form 10-Q.

Including the effects of commodity price swap agreements, total natural gas, natural gas liquids and condensate sales increased by $8.8 million for the three months ended September 30, 2014, consisting of an $11.4 million increase in sales of natural gas and a $4.0 million increase in drip condensate sales, partially offset by a $6.6 million decrease in NGLs sales.

The growth in natural gas sales for the three months ended September 30, 2014, was primarily due to increases of $7.5 million and $3.5 million at the DJ Basin complex and the Hilight system, respectively, due to increased sales volumes. The decline in NGLs sales for the three months ended September 30, 2014, was primarily due to decreases of $6.0 million and $2.2 million at the Red Desert complex and the Granger Straddle plant, respectively, due to lower volumes sold and a decrease in average swap price. These decreases were partially offset by an increase of $1.8 million at Hilight due to increased sales volumes, partially offset by a decrease in average swap price.

The increase in drip condensate sales for the three months ended September 30, 2014, was primarily due to an increase of $4.2 million at the DJ Basin complex, resulting from an increase in drip condensate volumes sold and average swap price, partially offset by a decrease at Hugoton of $0.2 million due to a decrease in drip condensate volumes sold.

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Including the effects of commodity price swap agreements, total natural gas, natural gas liquids and condensate sales increased by $50.6 million for the nine months ended September 30, 2014, consisting of $24.3 million in sales of natural gas, $18.3 million in NGLs sales and $8.0 million in drip condensate sales.
The growth in natural gas sales for the nine months ended September 30, 2014, was primarily due to increases of (i) $12.0 million at the Hilight system due to an increase in volumes sold, partially offset by a decrease in average swap price, (ii) $9.0 million at the DJ Basin complex due to an increase in both volumes sold and average swap prices, and (iii) $3.8 million at the Red Desert complex due to an increase in volumes sold.
The growth in NGLs sales for the nine months ended September 30, 2014, was primarily due to increases of (i) $16.0 million at the DJ Basin complex due to increases in both volumes sold and average swap price, (ii) $7.8 million at Chipeta due to an increase in volumes sold and (iii) $6.4 million at the Hilight system due to higher volumes processed and sold, partially offset by a decrease in average swap price. These increases were partially offset by a $9.5 million decrease at the Red Desert complex due to a decrease in volumes sold and average swap prices.
The increase in drip condensate sales for the nine months ended September 30, 2014, was primarily due to an increase of $9.1 million at the DJ Basin complex from an increase in drip condensate volumes sold and average swap price, partially offset by a decrease of $1.2 million at Hugoton due to a decrease in drip condensate volumes sold.

Equity Income, Net

	Three Months Ended September 30,			Nine Months Ended September 30,		
thousands except percentages	2014	2013	Inc/ (Dec)	2014	2013	Inc/ (Dec)
Equity income, net	$19,063	$4,520	NM	$41,322	$11,944	NM

For the three and nine months ended September 30, 2014, equity income, net increased by $14.5 million and $29.4 million, respectively, primarily driven by the start-up of (i) the Mont Belvieu JV fractionation trains in the fourth quarter 2013, (ii) TEG and TEP in the fourth quarter 2013 and (iii) FRP in March 2014.

Cost of Product and Operation and Maintenance Expenses

	Three Months Ended September 30,				Nine Months Ended September 30,			
thousands except percentages	2014	2013	Inc/ (Dec)		2014	2013	Inc/ (Dec)	
NGL purchases	$60,886	$50,684	20	%	$164,302	$144,293	14	%
Residue purchases	38,779	38,919	—	%	126,731	114,856	10	%
Other	8,728	3,913	123	%	27,395	10,910	151	%
Cost of product	108,393	93,516	16	%	318,428	270,059	18	%
Operation and maintenance	53,657	42,757	25	%	145,064	121,165	20	%
Total cost of product and operation and maintenance expenses	$162,050	$136,273	19	%	$463,492	$391,224	18	%

Cost of product expense for the three and nine months ended September 30, 2014 and 2013, includes the effects of commodity price swap agreements attributable to purchases for the Granger, Hilight, Hugoton, Newcastle and MGR assets, as well as the DJ Basin complex. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Item 1 of this Form 10-Q.
Including the effects of commodity price swap agreements on purchases, cost of product expense for the three months ended September 30, 2014, increased by $14.9 million primarily due to the volume fluctuations noted in Throughput and Natural Gas, Natural Gas Liquids and Condensate Sales within this Item 2, resulting in the following:

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a $10.2 million net increase in NGL purchases primarily at the DJ Basin complex, Hilight system and Chipeta, partially offset by a decrease at the Red Desert complex;

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- a $0.1 million net decrease in residue purchases, primarily driven by lower prices offset by higher volumes at the DJ Basin complex and the Hilight system; and
- a $4.8 million net increase in other items, primarily due to changes in imbalance positions at the DJ Basin complex.

Including the effects of commodity price swap agreements on purchases, cost of product expense for the nine months ended September 30, 2014, increased by $48.4 million primarily due to the volume fluctuations noted in Throughput and Natural Gas, Natural Gas Liquids and Condensate Sales within this Item 2, resulting in the following:

- a $20.0 million net increase in NGL purchases primarily at the DJ Basin complex, the Hilight system and Chipeta, partially offset by a decrease at the Red Desert complex;
- an $11.9 million net increase in residue purchases primarily at the Hilight system, the Granger straddle plant and Chipeta, partially offset by a decrease at the Granger complex; and
- a $16.5 million net increase in other items, primarily due to changes in imbalance positions at the DJ Basin complex and the Hilight system.

Operation and maintenance expense increased by $10.9 million for the three months ended September 30, 2014, primarily due to an increase of $3.8 million for plant repairs and maintenance primarily at the Bison facility, DJ Basin complex and the Brasada facility, an increase of $3.3 million attributable to the Non-Operated Marcellus Interest and an increase of $2.1 million in utilities, contract labor and consulting, and water costs primarily at the DJ Basin complex.

Operation and maintenance expense increased by $23.9 million for the nine months ended September 30, 2014, primarily due to an increase of $10.3 million for plant repairs and maintenance primarily at the Hilight system, DJ Basin complex and the Brasada facility, an increase of $7.0 million attributable to the Non-Operated Marcellus Interest and an increase of $4.1 million in utilities, chemicals and water costs primarily attributable to the DJ Basin complex.

General and Administrative, Depreciation and Other Expenses

	Three Months Ended September 30,				Nine Months Ended September 30,			
thousands except percentages	2014	2013	Inc/ (Dec)		2014	2013	Inc/ (Dec)	
General and administrative	$7,889	$7,276	8	%	$24,304	$22,228	9	%
Property and other taxes	6,564	6,649	(1	)%	20,718	18,520	12	%
Depreciation, amortization and impairments	45,651	37,615	21	%	130,009	106,551	22	%
Total general and administrative, depreciation and other expenses	$60,104	$51,540	17	%	$175,031	$147,299	19	%

General and administrative expenses increased by $0.6 million and $2.1 million for the three and nine months ended September 30, 2014, respectively, primarily due to an increase of $0.7 million and $2.1 million, respectively, in personnel costs for which we reimbursed Anadarko pursuant to our omnibus agreement, and an increase of $0.1 million and $0.6 million, respectively, in non-cash compensation expenses. These increases were offset by decreases of $0.2 million and $0.6 million, respectively, in legal, consulting and audit fees.

Property and other taxes decreased by $0.1 million for the three months ended September 30, 2014, primarily due to decreases in ad valorem taxes at the Brasada facility, Hugoton and Hilight system, which were offset by increases at the DJ Basin complex and Chipeta.

Property and other taxes increased by $2.2 million for the nine months ended September 30, 2014, primarily due to ad valorem tax increases of $2.6 million associated with the start-up of Train I at the Lancaster plant in April 2014 and compression expansion capital projects at the DJ Basin complex and the completion of the Brasada facility in June

2013 and $0.5 million at Chipeta, these increases were offset by a decrease of $0.9 million in accrued ad valorem taxes at the Hilight system, Hugoton, Helper and Pinnacle gathering systems.

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Depreciation, amortization and impairments increased by $8.0 million for the three months ended September 30, 2014, primarily attributable to a $5.1 million increase in depreciation expense associated with the start-up of Train I at the Lancaster plant in April 2014 and compression expansion capital projects at the DJ Basin complex, a $0.8 million increase in depreciation expense at the Non-Operated Marcellus Interest driven by additional capital projects, a $0.7 million increase in depreciation expense related to the September 2013 acquisition of OTTCO, and a $0.9 million impairment related to a compressor no longer in service at the Hilight system and the cancellation of various capital projects by the third-party operator of the Non-Operated Marcellus Interest.
Depreciation, amortization and impairments increased by $23.5 million for the nine months ended September 30, 2014, primarily attributable to a $10.7 million increase in depreciation expense associated with the start-up of Train I at the Lancaster plant in April 2014 and compression expansion capital projects at the DJ Basin complex, a $3.8 million increase in depreciation expense due to the completion of the Brasada facility in June 2013, a $3.4 million increase at the Marcellus Non-Operated Interest driven by additional capital projects, a $2.3 million increase in depreciation expense related to the September 2013 acquisition of OTTCO, a $1.5 million and $1.1 million increase in depreciation expense at the Hilight system and the Anadarko-Operated Marcellus Interest, respectively, related to capital projects, and an impairment of $1.0 million in the first quarter of 2014 related to a non-operational plant in the Powder River Basin with no comparative activity in the prior period. In addition, during the nine months ended September 30, 2014, impairment expense of $0.5 million was recognized related to a compressor no longer in service at the Hilight system and $0.8 million related to the cancellation of various capital projects by the third-party operator of the Non-Operated Marcellus Interest.

Interest Income, Net – Affiliates and Interest Expense

	Three Months Ended September 30,			Nine Months Ended September 30,		
thousands except percentages	2014	2013	Inc/ (Dec)	2014	2013	Inc/ (Dec)
Interest income on note receivable	$4,225	$4,225	— %	$12,675	$12,675	— %
Interest income, net – affiliates	$4,225	$4,225	— %	$12,675	$12,675	— %
Interest expense on long-term debt	$(21,671)	$(14,994)	45 %	$(59,251)	$(43,783)	35 %
Amortization of debt issuance costs and commitment fees	(1,107)	(1,135)	(2)%	(3,799)	(3,252)	17 %
Capitalized interest	1,900	3,111	(39)%	7,347	9,552	(23)%
Interest expense	$(20,878)	$(13,018)	60 %	$(55,703)	$(37,483)	49 %

Interest expense increased by $7.9 million and $18.2 million for the three and nine months ended September 30, 2014, respectively, primarily due to interest expense incurred on the 5.450% Senior Notes due 2044 of $5.5 million and $11.6 million, respectively, as well as interest incurred on the 2.600% Senior Notes due 2018 of $1.4 million and $5.4 million, respectively. Amortization of debt issuance costs and commitment fees increased by $0.5 million for the nine months ended September 30, 2014 primarily due to the issuance of the 2.600% Senior Notes due 2018. These increases were partially offset by a decrease in interest expense on the RCF of $0.2 million and $1.5 million for the three and nine months ended September 30, 2014, respectively, due to lower average outstanding borrowings in the current period. Capitalized interest decreased by $1.2 million and $2.2 million for the three and nine months ended September 30, 2014, respectively, primarily due to the completion of the Brasada facility during 2013, partially offset by an increase in capitalized interest for the construction of Train II at the Lancaster processing plant. See Note 8—Debt and Interest Expense in the Notes to Consolidated Financial Statements under Item 1 of this Form 10-Q.

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Income Tax (Benefit) Expense

	Three Months Ended September 30,			Nine Months Ended September 30,		
thousands except percentages	2014	2013	Inc/ (Dec)	2014	2013	Inc/ (Dec)
Income before income taxes	$106,818	$81,855	30 %	$296,425	$200,895	48 %
Income tax (benefit) expense	278	(27)	NM	276	4,192	(93)%
Effective tax rate	— %	— %		— %	2 %	

We are not a taxable entity for U.S. federal income tax purposes; however, income apportionable to Texas is subject to Texas margin tax. For the periods presented, our variance from the federal statutory rate, which is zero percent as a non-taxable entity, is primarily due to federal and state taxes on pre-acquisition income attributable to Partnership assets acquired from Anadarko, and our share of Texas margin tax.

Income attributable to (a) the TEFR Interests prior to and including February 2014 and (b) the Non-Operated Marcellus Interest prior to and including February 2013 was subject to federal and state income tax. Income earned on the TEFR Interests and the Non-Operated Marcellus Interest for periods subsequent to February 2014 and February 2013, respectively, was only subject to Texas margin tax on income apportionable to Texas.

Noncontrolling Interest

	Three Months Ended September 30,			Nine Months Ended September 30,		
thousands except percentages	2014	2013	Inc/ (Dec)	2014	2013	Inc/ (Dec)
Net income attributable to noncontrolling interest	$3,863	$3,376	14 %	$11,005	$7,467	47 %

For the three and nine months ended September 30, 2014, net income attributable to noncontrolling interest increased by $0.5 million and $3.5 million, respectively, primarily due to increased revenues at Chipeta driven by increased drilling activities in the Uintah Basin.

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KEY PERFORMANCE METRICS

thousands except percentages and per-unit amounts	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Inc/ (Dec)		Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013	Inc/ (Dec)	
Adjusted gross margin attributable to Western Gas Partners, LP for natural gas assets (1)	$213,901	$175,348	22	%	$607,583	$472,827	29	%
Adjusted gross margin for crude/NGL assets (2)	19,396	4,031	NM		51,692	10,996	NM	
Adjusted gross margin attributable to Western Gas Partners, LP	233,297	179,379	30	%	659,275	483,823	36	%
Adjusted gross margin per Mcf attributable to Western Gas Partners, LP for natural gas assets (3)	0.67	0.58	16	%	0.64	0.56	14	%
Adjusted gross margin per Bbl for crude/NGL assets (4)	1.53	1.39	10	%	1.71	1.43	20	%
Adjusted EBITDA attributable to Western Gas Partners, LP (5)	167,297	125,176	34	%	475,594	328,750	45	%
Distributable cash flow (5)	136,722	105,883	29	%	392,996	274,795	43	%

(1) Adjusted gross margin attributable to Western Gas Partners, LP for natural gas assets is calculated as total revenues for natural gas assets less cost of product for natural gas assets plus distributions from our equity investments in Fort Union and Rendezvous, which are measured in Mcf, and excluding the noncontrolling interest owner's proportionate share of revenue and cost of product. See the reconciliation of Adjusted gross margin attributable to Western Gas Partners, LP for natural gas assets to its most comparable GAAP measure below.

(2) Adjusted gross margin for crude/NGL assets is calculated as total revenues for crude/NGL assets less cost of product for crude/NGL assets plus distributions from our equity investments in White Cliffs, the Mont Belvieu JV, TEG, TEP and FRP, which are measured in barrels. See the reconciliation of Adjusted gross margin for crude/NGL assets to its most comparable GAAP measure below.

(3) Average for period. Calculated as Adjusted gross margin attributable to Western Gas Partners, LP for natural gas assets, divided by total throughput (MMcf/d) attributable to Western Gas Partners, LP for natural gas assets.

(4) Average for period. Calculated as Adjusted gross margin for crude/NGL assets, divided by total throughput (MBbls/d) for crude/NGL assets.

(5) For reconciliations of Adjusted EBITDA attributable to Western Gas Partners, LP and Distributable cash flow to their most directly comparable financial measures calculated and presented in accordance with GAAP, see the descriptions below.

Adjusted gross margin attributable to Western Gas Partners, LP . We define Adjusted gross margin attributable to Western Gas Partners, LP ("Adjusted gross margin") as total revenues less cost of product, plus distributions from equity investees and excluding the noncontrolling interest owner's proportionate share of revenue and cost of product. We believe Adjusted gross margin is an important performance measure of the core profitability of our operations, as well as our operating performance as compared to that of other companies in our industry.

Adjusted gross margin increased by $53.9 million and $175.5 million for the three and nine months ended September 30, 2014, respectively, primarily due to higher margins at the DJ Basin complex (including the start-up of the Lancaster plant in April 2014), the start-up of the Brasada facility in June 2013, higher margins on the Non-Operated Marcellus Interest, the fourth quarter 2013 start-up of the Mont Belvieu fractionation trains, the fourth quarter 2013 start-up of TEG and TEP, and the March 2014 start-up of FRP. In addition, for the nine months ended September 30, 2014, higher margins on Chipeta contributed to the increase.

To facilitate investor and industry analyst comparisons between us and our peers, we also disclose Adjusted gross margin per Mcf attributable to Western Gas Partners, LP for natural gas assets and Adjusted gross margin per Bbl for crude/NGL assets. Adjusted gross margin per Mcf attributable to Western Gas Partners, LP for natural gas assets increased by $0.09 and $0.08 for the three and nine months ended September 30, 2014, respectively, primarily due to the consolidation of several systems into the DJ Basin complex beginning in the first quarter of 2014, as well as the start-up of the Lancaster plant in April 2014, and higher margins at Chipeta and the Non-Operated Marcellus Interest, partially offset by margin declines at the Red Desert complex. Adjusted gross margin per Bbl for crude/NGL assets increased by $0.14 and $0.28 for the three and nine months ended September 30, 2014, respectively, due to distributions received from the Mont Belvieu JV and the TEFR Interests.

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Adjusted EBITDA attributable to Western Gas Partners, LP. We define Adjusted EBITDA attributable to Western Gas Partners, LP ("Adjusted EBITDA") as net income attributable to Western Gas Partners, LP, plus distributions from equity investees, non-cash equity-based compensation expense, interest expense, income tax expense, depreciation, amortization and impairments, and other expense, less income from equity investments, interest income, income tax benefit, and other income. 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 consolidated financial statements, such as industry analysts, investors, commercial banks and rating agencies, use to assess the following, among other measures:

- 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 cash flow to make distributions; and
- the viability of acquisitions and capital expenditure projects and the returns on investment of various investment opportunities.

Adjusted EBITDA increased by $42.1 million for the three months ended September 30, 2014, primarily due to a $53.0 million increase in total revenues and a $16.3 million increase in distributions from equity investees. These amounts were offset by a $14.9 million increase in cost of product, a $10.9 million increase in operation and maintenance expenses, a $0.5 million increase in general and administrative expenses excluding non-cash equity-based compensation expense, and a $0.5 million increase in net income attributable to noncontrolling interest.
Adjusted EBITDA increased by $146.8 million for the nine months ended September 30, 2014, primarily due to a $185.2 million increase in total revenues and a $41.9 million increase in distributions from equity investees. These amounts were offset by a $48.4 million increase in cost of product, a $23.9 million increase in operation and maintenance expenses, a $3.5 million increase in net income attributable to noncontrolling interest, a $2.2 million increase in property and other tax expense, and a $1.6 million increase in general and administrative expenses excluding non-cash equity-based compensation expense.

Distributable cash flow. We define "Distributable cash flow" as Adjusted EBITDA, plus interest income, less net cash paid for interest expense (including amortization of deferred debt issuance costs originally paid in cash, offset by non-cash capitalized interest), maintenance capital expenditures, and income taxes. We compare Distributable cash flow to the cash distributions we expect to pay our unitholders. Using this measure, management can quickly compute the Coverage ratio of distributable cash flow to planned cash distributions. We believe Distributable cash flow is useful to investors because this measurement is used by many companies, analysts and others in the industry as a performance measurement tool to evaluate our operating and financial performance and compare it with the performance of other publicly traded partnerships.
While Distributable cash flow is a measure we use to assess our ability to make distributions to our unitholders, it should not be viewed as indicative of the actual amount of cash that we have available for distributions or that we plan to distribute for a given period.
Distributable cash flow increased by $30.8 million for the three months ended September 30, 2014, primarily due to a $42.1 million increase in Adjusted EBITDA, offset by a $6.6 million increase in net cash paid for interest expense and a $4.6 million increase in cash paid for maintenance capital expenditures.
Distributable cash flow increased by $118.2 million for the nine months ended September 30, 2014, primarily due to a $146.8 million increase in Adjusted EBITDA, offset by a $16.0 million increase in net cash paid for interest expense and a $13.0 million increase in cash paid for maintenance capital expenditures.

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Reconciliation to GAAP measures. Adjusted gross margin, Adjusted EBITDA and Distributable cash flow are not defined in GAAP. The GAAP measure used by us that is most directly comparable to Adjusted gross margin is operating income, while net income attributable to Western Gas Partners, LP and net cash provided by operating activities are the GAAP measures used by us that are most directly comparable to Adjusted EBITDA. The GAAP measure used by us that is most directly comparable to Distributable cash flow is net income attributable to Western Gas Partners, LP. Our non-GAAP financial measures of Adjusted gross margin, Adjusted EBITDA and Distributable cash flow should not be considered as alternatives to the GAAP measures of operating income, net income attributable to Western Gas Partners, LP, net cash provided by operating activities or any other measure of financial performance presented in accordance with GAAP. Adjusted gross margin, Adjusted EBITDA and Distributable cash flow have important limitations as analytical tools because they exclude some, but not all, items that affect operating income, net income and net cash provided by operating activities. Adjusted gross margin, Adjusted EBITDA and Distributable cash flow should not be considered in isolation or as a substitute for analysis of our results as reported under GAAP. Our definitions of Adjusted gross margin, Adjusted EBITDA and Distributable cash flow may not be comparable to similarly titled measures of other companies in our industry, thereby diminishing their utility.

Management compensates for the limitations of Adjusted gross margin, Adjusted EBITDA and Distributable cash flow as analytical tools by reviewing the comparable GAAP measures, understanding the differences between Adjusted gross margin, Adjusted EBITDA and Distributable cash flow compared to (as applicable) operating income, 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.

The following tables present (a) a reconciliation of the non-GAAP financial measure of Adjusted gross margin to the GAAP measure of operating income, (b) a reconciliation of the non-GAAP financial measure of Adjusted EBITDA to the GAAP financial measures of net income attributable to Western Gas Partners, LP and net cash provided by operating activities, and (c) a reconciliation of the non-GAAP financial measure of Distributable cash flow to the GAAP financial measure of net income attributable to Western Gas Partners, LP:

	Three Months Ended September 30,		Nine Months Ended September 30,	
thousands	2014	2013	2014	2013
Reconciliation of Adjusted gross margin attributable to Western Gas Partners, LP to Operating income				
Adjusted gross margin attributable to Western Gas Partners, LP for natural gas assets	$213,901	$175,348	$607,583	$472,827
Adjusted gross margin for crude/NGL assets	19,396	4,031	51,692	10,996
Adjusted gross margin attributable to Western Gas Partners, LP	233,297	179,379	659,275	483,823
Adjusted gross margin attributable to noncontrolling interest	5,582	5,138	15,611	12,351
Equity income, net	19,063	4,520	41,322	11,944
Less:				
Distributions from equity investees	20,807	4,531	57,448	15,563
Operation and maintenance	53,657	42,757	145,064	121,165
General and administrative	7,889	7,276	24,304	22,228
Property and other taxes	6,564	6,649	20,718	18,520
Depreciation, amortization and impairments	45,651	37,615	130,009	106,551
Operating income	$123,374	$90,209	$338,665	$224,091

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thousands	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
Reconciliation of Adjusted EBITDA attributable to Western Gas Partners, LP to Net income attributable to Western Gas Partners, LP				
Adjusted EBITDA attributable to Western Gas Partners, LP	$167,297	$125,176	$475,594	$328,750
Less:				
Distributions from equity investees	20,807	4,531	57,448	15,563
Non-cash equity-based compensation expense	1,034	962	3,188	2,663
Interest expense	20,878	13,018	55,703	37,483
Income tax expense	278	—	504	4,219
Depreciation, amortization and impairments (1)	45,005	36,970	128,083	104,651
Add:				
Equity income, net	19,063	4,520	41,322	11,944
Interest income, net – affiliates	4,225	4,225	12,675	12,675
Other income (1) (2)	94	39	251	419
Income tax benefit	—	27	228	27
Net income attributable to Western Gas Partners, LP	$102,677	$78,506	$285,144	$189,236
Reconciliation of Adjusted EBITDA attributable to Western Gas Partners, LP to Net cash provided by operating activities				
Adjusted EBITDA attributable to Western Gas Partners, LP	$167,297	$125,176	$475,594	$328,750
Adjusted EBITDA attributable to noncontrolling interest	4,506	4,017	12,922	9,362
Interest income (expense), net	(16,653)	(8,793)	(43,028)	(24,808)
Non-cash equity-based compensation expense	(11)	(80)	22	(99)
Debt-related amortization and other items, net	687	630	2,045	1,756
Current income tax benefit (expense)	(99)	9,888	366	25,024
Other income (expense), net (2)	97	43	260	424
Distributions from equity investments in excess of cumulative earnings	(4,539)	—	(14,387)	—
Changes in operating working capital:				
Accounts receivable, net	(18,055)	(580)	(41,408)	(27,387)
Accounts and natural gas imbalance payables and accrued liabilities, net	8,942	6,482	9,736	6,818
Other	(2,602)	(2,758)	1,645	(2,523)
Net cash provided by operating activities	$139,570	$134,025	$403,767	$317,317
Cash flow information of Western Gas Partners, LP				
Net cash provided by operating activities			$403,767	$317,317
Net cash used in investing activities			(913,372)	(1,432,048)
Net cash provided by financing activities			476,714	733,114

(1) Includes our 75% share of depreciation, amortization and impairments, and other income attributable to Chipeta.

(2) Excludes income of zero and $0.4 million for the three months ended September 30, 2014 and 2013, respectively, and $0.5 million and $1.2 million for the nine months ended September 30, 2014 and 2013, respectively, related to a component of a gas processing agreement accounted for as a capital lease.

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thousands except Coverage ratio	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
Reconciliation of Distributable cash flow to Net income attributable to Western Gas Partners, LP and calculation of the Coverage ratio				
Distributable cash flow	$136,722	$105,883	$392,996	$274,795
Less:				
Distributions from equity investees	20,807	4,531	57,448	15,563
Non-cash equity-based compensation expense	1,035	962	3,188	2,663
Income tax (benefit) expense	278	(27)	276	4,192
Depreciation, amortization and impairments [(1)]	45,005	36,970	128,083	104,651
Add:				
Equity income, net	19,063	4,520	41,322	11,944
Cash paid for maintenance capital expenditures [(1)]	12,023	7,389	32,563	19,595
Capitalized interest [(2)]	1,900	3,111	7,347	9,552
Cash paid for (reimbursement of) income taxes	—	—	(340)	—
Other income [(1)] [(3)]	94	39	251	419
Net income attributable to Western Gas Partners, LP	$102,677	$78,506	$285,144	$189,236
Distributions declared [(4)]				
Limited partners	$80,373		$231,476	
General partner	31,236		84,537	
Total	$111,609		$316,013	
Coverage ratio	1.23 x		1.24 x	

(1) Includes our 75% share of depreciation, amortization and impairments; cash paid for maintenance capital expenditures; and other income attributable to Chipeta.

(2) Includes capitalized interest of $1.1 million and $1.5 million for the three and nine months ended September 30, 2013, respectively, for the construction of the Mont Belvieu JV, reflected as a component of the equity investment balance.

(3) Excludes income of zero and $0.4 million for the three months ended September 30, 2014 and 2013, respectively, and $0.5 million and $1.2 million for the nine months ended September 30, 2014 and 2013, respectively, related to a component of a gas processing agreement accounted for as a capital lease.

(4) Reflects distributions of $0.675 and $1.95 per unit declared for the three and nine months ended September 30, 2014, respectively.

LIQUIDITY AND CAPITAL RESOURCES

Our primary cash requirements are for acquisitions and capital expenditures, debt service, customary operating expenses, quarterly distributions to our limited partners and general partner, and distributions to our noncontrolling interest owner. Our sources of liquidity as of September 30, 2014, included cash and cash equivalents, cash flows generated from operations, interest income on our $260.0 million note receivable from Anadarko, available borrowing capacity under our RCF, and issuances of additional equity or debt securities. We believe that cash flows generated from these sources will be sufficient to satisfy our short-term working capital requirements and long-term maintenance and expansion capital expenditure requirements. The amount of future distributions to unitholders will depend on our results of operations, financial condition, capital requirements and other factors, and will be determined by the board of directors of our general partner on a quarterly basis. Due to our cash distribution policy, we expect to rely on external financing sources, including equity and debt issuances, to fund expansion capital expenditures and future acquisitions. However, to limit interest expense, we may use operating cash flows to fund expansion capital expenditures or acquisitions, which could result in subsequent borrowings under our RCF to pay distributions or fund other short-term working capital requirements.

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Our partnership agreement requires that we distribute all of our available cash (as defined in the partnership agreement) to unitholders of record on the applicable record date within 45 days of the end of each quarter. We have made cash distributions to our unitholders each quarter since our initial public offering and have increased our quarterly distribution each quarter since the second quarter of 2009. On October 20, 2014, the board of directors of our general partner declared a cash distribution to our unitholders of $0.675 per unit, or $111.6 million in aggregate, including incentive distributions. The cash distribution is payable on November 13, 2014, to unitholders of record at the close of business on October 31, 2014.
Management continuously monitors our leverage position and coordinates our capital expenditure program, quarterly distributions and acquisition strategy with our expected cash flows and projected debt-repayment schedule. We will continue to evaluate funding alternatives, including additional borrowings and the issuance of debt or equity securities, to secure funds as needed or to refinance outstanding debt balances with longer-term notes. To facilitate a potential debt or equity securities issuance, we have the ability to sell securities under our shelf registration statements. Our ability to generate cash flows is subject to a number of factors, some of which are beyond our control. Please read Part II, Item 1A—Risk Factors of this Form 10-Q.

Working capital. As of September 30, 2014, we had $0.3 million of working capital deficit, which we define as the amount by which current liabilities exceed current assets. Working capital 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 and factors such as credit extended to, and the timing of collections from, our customers, and the level and timing of our spending for maintenance and expansion activity. Our working capital deficit as of September 30, 2014, is primarily due to the costs incurred related to projects at the DJ Basin complex, which include the continued construction of a second train and compressor expansions. As of September 30, 2014, we had $1.0 billion available for borrowing under our RCF. See Note 8—Debt and Interest Expense and Note 10—Subsequent Event in the Notes to Consolidated Financial Statements under Item 1 of this Form 10-Q.

Capital expenditures. Our business is capital intensive, requiring significant investment to maintain and improve existing facilities or develop new midstream infrastructure. We categorize capital expenditures as either of the following:

- maintenance capital expenditures, which include those expenditures required to maintain the existing operating capacity and service capability of our assets, such as to replace system components and equipment that have been subject to significant use over time, become obsolete or reached the end of their useful lives, to remain in compliance with regulatory or legal requirements or to complete additional well connections to maintain existing system throughput and related cash flows (for fiscal year 2014, the general partner’s board of directors has approved Estimated Maintenance Capital Expenditures (as defined in our partnership agreement) of $15.3 million per quarter); or

- expansion capital expenditures, which include expenditures to construct new midstream infrastructure and those expenditures incurred to extend the useful lives of our assets, reduce costs, increase revenues or increase system throughput or capacity from current levels, including well connections that increase existing system throughput.

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Capital expenditures in the consolidated statements of cash flows reflect capital expenditures on a cash basis, when payments are made. Capital incurred is presented on an accrual basis. Capital expenditures as presented in the consolidated statements of cash flows and capital incurred were as follows:

	Nine Months Ended September 30,	
thousands	2014	2013
Acquisitions	$372,393	$710,158
Expansion capital expenditures	$459,301	$450,107
Maintenance capital expenditures (1)	32,803	19,571
Total capital expenditures (1) (2)	$492,104	$469,678
Capital incurred (3)	$490,326	$458,236

(1) Maintenance capital expenditures for the nine months ended September 30, 2014 and 2013, are presented net of $0.2 million and zero, respectively, of contributions in aid of construction costs from affiliates.

(2) Capital expenditures for the nine months ended September 30, 2014 and 2013, included $7.3 million and $8.0 million, respectively, of capitalized interest. Capital expenditures included the noncontrolling interest owner's share of Chipeta's capital expenditures, funded by contributions from the noncontrolling interest owner for all periods presented.

(3) Includes the noncontrolling interest owner's share of Chipeta's capital incurred, funded by contributions from the noncontrolling interest owner for all periods presented. Capital incurred for the nine months ended September 30, 2014 and 2013, included $7.3 million and $8.0 million, respectively, of capitalized interest. Capital incurred for the nine months ended September 30, 2013, included $8.8 million of pre-acquisition capital incurred for the Non-Operated Marcellus Interest.

Acquisitions included the TEFR Interests in the first quarter of 2014, OTTCO in the third quarter of 2013, the Mont Belvieu JV in the second quarter of 2013, and the Anadarko-Operated Marcellus Interest and the Non-Operated Marcellus Interest in the first quarter of 2013. See Note 2—Acquisitions in the Notes to Consolidated Financial Statements under Item 1 of this Form 10-Q.

Capital expenditures, excluding acquisitions, increased by $22.4 million for the nine months ended September 30, 2014. Expansion capital expenditures increased by $9.2 million (including a $0.7 million decrease in capitalized interest) for the nine months ended September 30, 2014, primarily due to an increase of $118.4 million at the DJ Basin complex, related to compression projects and well connections, as well as the continued construction of a second train. In addition, there was an increase of $17.4 million at the Haley gathering system, $8.7 million at the Hilight system, $5.1 million at the Anadarko-Operated Marcellus Interest and $4.9 million at Chipeta. These increases were partially offset by a $93.1 million decrease at the Brasada facility due to construction being completed in June 2013 and a $53.4 million decrease at the Non-Operated Marcellus Interest. Maintenance capital expenditures increased by $13.2 million, primarily as a result of increased expenditures of $7.0 million at the DJ Basin complex, $4.8 million at the Non-Operated Marcellus Interest and $1.0 million at the Red Desert complex.

We have updated our estimated total capital expenditures for the year ending December 31, 2014, including our 75% share of Chipeta's capital expenditures and excluding acquisitions and equity investments, from an originally reported range of $668 million to $718 million, to a current range of $628 million to $678 million. Total capital expenditures including equity investments, but excluding acquisitions, are expected to be between $670 million and $720 million.

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Historical cash flow. The following table and discussion present a summary of our net cash flows provided by (used in) operating activities, investing activities and financing activities:

	Nine Months Ended September 30,	
thousands	2014	2013
Net cash provided by (used in):		
Operating activities	$403,767	$317,317
Investing activities	(913,372)	(1,432,048)
Financing activities	476,714	733,114
Net increase (decrease) in cash and cash equivalents	$(32,891)	$(381,617)

Operating Activities. Net cash provided by operating activities during the nine months ended September 30, 2014, increased primarily due to the impact of changes in working capital items, as well as $4.7 million of proceeds received from an insurance claim settlement for business interruption at the Chipeta gas processing plant in 2013.
Refer to Operating Results within this Item 2 for a discussion of our results of operations as compared to the prior periods.

Investing Activities. Net cash used in investing activities for the nine months ended September 30, 2014, included the following:

- $492.1 million of capital expenditures, net of $0.2 million of contributions in aid of construction costs from affiliate, primarily related to projects at the DJ Basin complex, which include the continued construction of a second train and compressor expansions;
- $356.3 million of cash paid for the acquisition of the TEFR Interests;
- $40.0 million of cash paid related to FRP construction, which was completed in March 2014;
- $16.1 million of cash paid for equipment purchases from Anadarko;
- $14.4 million of distributions from equity investments in excess of cumulative earnings;
- $10.5 million of cash paid for a White Cliffs expansion project; and
- $6.3 million of cash paid related to TEP construction, which was completed in November 2013.

Net cash used in investing activities for the nine months ended September 30, 2013, included the following:

- $469.7 million of capital expenditures;
- $465.5 million of cash paid for the Non-Operated Marcellus Interest acquisition;
- $205.6 million of capital contributions to TEG, TEP and FRP for construction costs;
- $134.6 million of cash paid for the Anadarko-Operated Marcellus Interest acquisition;
- $78.1 million of cash paid for the Mont Belvieu JV acquisition;
- $27.5 million of cash paid for the OTTCO acquisition;

- $27.6 million of capital contributions to the Mont Belvieu JV to fund our share of construction costs for the fractionation facilities;

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- $19.1 million of cash paid for a White Cliffs expansion project; and

- $4.4 million of cash paid for equipment purchases from Anadarko.

Financing Activities. Net cash provided by financing activities for the nine months ended September 30, 2014, included the following:

- $389.5 million of net proceeds from the 2044 Notes offering in March 2014, after underwriting and original issue discounts and offering costs, all of which was used to repay a portion of our outstanding borrowings under our RCF, including $350.0 million of borrowings to fund the acquisition of the TEFR Interests;

- $350.0 million of borrowings to fund the acquisition of the TEFR Interests;

- $300.0 million of borrowings to fund capital expenditures and for general partnership purposes;

- $100.0 million of net proceeds from the additional 2018 Notes offering in March 2014, after underwriting discounts, original issue premium and offering costs, part of which was used to repay a portion of our outstanding borrowings under our RCF;

- $83.3 million of net proceeds from activity under the Continuous Offering Program (as defined and discussed in Registered Securities within this Item 2), including net proceeds from the issuance of general partner units to our general partner to maintain its 2.0% general partner interest;

- $18.1 million of net proceeds related to the partial exercise of the underwriters' over-allotment option granted in connection with our December 2013 equity offering; and

- $0.4 million of net proceeds from the issuance of general partner units to our general partner to maintain its 2.0% general partner interest after common units were issued in conjunction with the acquisition of the TEFR Interests.

Net contributions from Anadarko attributable to intercompany balances were $23.8 million during the nine months ended September 30, 2014, representing intercompany transactions attributable to the acquisition of the TEFR Interests.

Net cash provided by financing activities for the nine months ended September 30, 2013, included the following:

- $424.7 million of net proceeds from our May 2013 equity offering, $245.0 million of which was used to repay a portion of our outstanding borrowings under our RCF;

- $250.0 million of borrowings to fund the Non-Operated Marcellus Interest acquisition;

- $247.6 million of net proceeds from our 2018 Notes offering in August 2013, after underwriting and original issue discounts and offering costs, all of which was used to repay a portion of our outstanding borrowings under our RCF;

- $184.0 million of borrowings to fund capital expenditures;

- $133.5 million of borrowings to fund the Anadarko-Operated Marcellus Interest acquisition;

- $27.5 million of borrowings to fund the OTTCO acquisition;

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- $2.6 million of net proceeds from activity under the Continuous Offering Program (as defined and discussed in Registered Securities within this Item 2), including net proceeds from the issuance of general partner units to our general partner to maintain its 2.0% general partner interest; and

- $0.5 million of net proceeds from the issuance of general partner units to our general partner to maintain its 2.0% general partner interest after common units were issued in conjunction with the Non-Operated Marcellus Interest acquisition.

Net contributions from Anadarko attributable to intercompany balances were $181.9 million during the nine months ended September 30, 2013, representing intercompany transactions attributable to the acquisitions of the TEFR Interests and the Non-Operated Marcellus Interest.

For the nine months ended September 30, 2014 and 2013, we paid $297.0 million and $215.1 million, respectively, of cash distributions to our unitholders. Contributions from the noncontrolling interest owner of Chipeta totaled zero and $2.2 million during the nine months ended September 30, 2014 and 2013, respectively, primarily for expansion of the cryogenic units and plant construction. Distributions to the noncontrolling interest owner of Chipeta totaled $11.3 million and $8.0 million for the nine months ended September 30, 2014 and 2013, respectively, representing the distributions paid as of September 30 of the respective year.

Debt and credit facility. At September 30, 2014, our debt outstanding consisted of $500.0 million aggregate principal amount of 5.375% Senior Notes due 2021 (the “2021 Notes”), $670.0 million aggregate principal amount of 4.000% Senior Notes due 2022 (the “2022 Notes”), $350.0 million aggregate principal amount of 2.600% Senior Notes due 2018 (the “2018 Notes”), and $400.0 million aggregate principal amount of 5.450% Senior Notes due 2044 (the “2044 Notes”), and the RCF. The two tranches of the 2022 Notes, issued in June and October 2012, were issued under the same indenture and are considered a single class of securities. The two tranches of the 2018 Notes, issued in August 2013 and March 2014, were issued under the same indenture and are considered a single class of securities. As of September 30, 2014, the carrying value of our outstanding debt consisted of $495.6 million of 2021 Notes, $673.0 million of 2022 Notes, $350.5 million of 2018 Notes, $393.8 million of 2044 Notes and $170.0 million of borrowings under the RCF. See Note 8—Debt and Interest Expense in the Notes to Consolidated Financial Statements under Item 1 of this Form 10-Q.

Senior Notes. The 2044 Notes issued in March 2014 were offered at a price to the public of 98.443% of the face amount. Including the effects of the issuance and underwriting discounts, the effective interest rate of the 2044 Notes is 5.633%. Interest is paid semi-annually on April 1 and October 1 of each year. Proceeds (net of underwriting discount of $3.5 million, original issue discount and debt issuance costs) were used to repay amounts then outstanding under our RCF and for general partnership purposes.
The 2018 Notes issued in March 2014 were offered at a price to the public of 100.857% of the face amount. Including the effects of the issuance premium for the March 2014 offering, the issuance discount for the August 2013 offering of 2018 Notes, and underwriting discounts, the effective interest rate of the 2018 Notes is 2.743%. Interest is paid semi-annually on February 15 and August 15 of each year. Proceeds (net of underwriting discount of $0.6 million, original issue premium and debt issuance costs) were used to repay amounts then outstanding under our RCF and for general partnership purposes.
At September 30, 2014, we were in compliance with all covenants under the indentures governing the 2021 Notes, 2022 Notes, 2018 Notes, and 2044 Notes.

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Revolving credit facility. In February 2014, we entered into an amended and restated $1.2 billion senior unsecured RCF, which is expandable to a maximum of $1.5 billion, replacing an $800.0 million credit facility, which was originally entered into in March 2011. Subsequent to February 2014, we borrowed $350.0 million under the RCF to fund the acquisition of the TEFR Interests (see Note 2—Acquisitions in the Notes to Consolidated Financial Statements under Item 1 of this Form 10-Q). The RCF matures in February 2019 and bears interest at London Interbank Offered Rate (“LIBOR”), plus applicable margins ranging from 0.975% to 1.45%, or an alternate base rate equal to the greatest of (a) the Prime Rate, (b) the Federal Funds Effective Rate plus 0.5%, or (c) LIBOR plus 1%, in each case plus applicable margins currently ranging from zero to 0.45%, based upon our senior unsecured debt rating. As of September 30, 2014, we had $170.0 million of outstanding borrowings, $12.8 million in outstanding letters of credit and $1.0 billion available for borrowing under the RCF. The interest rate on the RCF was 1.46% at September 30, 2014. At December 31, 2013, the interest rate on the previous credit facility was 1.67%. We are required to pay a quarterly facility fee currently ranging from 0.15% to 0.30% of the commitment amount (whether used or unused), based upon our senior unsecured debt rating. The facility fee rate was 0.20% and 0.25% at September 30, 2014, and December 31, 2013, respectively. At September 30, 2014, we were in compliance with all covenants under the RCF. See Note 10—Subsequent Event in the Notes to Consolidated Financial Statements under Item 1 of this Form 10-Q.

The 2021 Notes, 2022 Notes, 2018 Notes, 2044 Notes and obligations under the RCF are recourse to our general partner. Our general partner is indemnified by a wholly owned subsidiary of Anadarko, Western Gas Resources, Inc. (“WGRI”), against any claims made against our general partner under the 2022 Notes, 2021 Notes, and/or the RCF.

In connection with the acquisitions of the Non-Operated Marcellus Interest, the Anadarko-Operated Marcellus Interest, and the TEFR Interests, our general partner and other wholly owned subsidiaries of Anadarko entered into indemnification agreements, whereby such subsidiaries agreed to indemnify our general partner for any recourse liability it may have for RCF borrowings, or other debt financing, attributable to the acquisitions of the Non-Operated Marcellus Interest, the Anadarko-Operated Marcellus Interest, and the TEFR Interests. These indemnification agreements apply to the 2044 Notes, 2018 Notes, and/or RCF borrowings outstanding related to the aforementioned acquisitions.

Our general partner, the other indemnifying subsidiaries of Anadarko and WGRI also amended and restated the indemnity agreements between them to (i) conform language among all the indemnification agreements and (ii) reduce the amount for which WGRI would indemnify our general partner by an amount equal to any amounts payable to the general partner under the indemnification agreements related to the acquisitions of the Non-Operated Marcellus Interest, the Anadarko-Operated Marcellus Interest, and the TEFR Interests.

Registered securities. We may issue an indeterminate amount of common units and various debt securities under our effective shelf registration statements on file with the SEC.

In August 2012, we filed a registration statement with the SEC authorizing the issuance of up to an aggregate of $125.0 million of common units, in amounts, at prices and on terms to be determined by market conditions and other factors at the time of our offerings. See Note 4—Equity and Partners’ Capital in the Notes to Consolidated Financial Statements under Item 1 of this Form 10-Q for a discussion of trades completed under the Continuous Offering Program. As of September 30, 2014, we had used all the capacity to issue common units under this registration statement.

In August 2014, we filed a registration statement with the SEC authorizing the issuance of up to an aggregate of $500.0 million of common units, in amounts, at prices and on terms to be determined by market conditions and other factors at the time of our offerings. As of September 30, 2014, we had not issued any common units under such registration statement.

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Credit risk. We bear credit risk represented by our exposure to non-payment or non-performance by our counterparties, including Anadarko, financial institutions, customers and other parties. Generally, non-payment or non-performance results from a customer's inability to satisfy payables to us for services rendered or volumes owed pursuant to gas imbalance agreements. We examine and monitor the creditworthiness of third-party customers and may establish credit limits for third-party customers. A substantial portion of our throughput, however, comes from producers that have investment-grade ratings.

We are dependent upon a single producer, Anadarko, for the substantial majority of our natural gas volumes, and we do not maintain a credit limit with respect to Anadarko. Consequently, we are subject to the risk of non-payment or late payment by Anadarko for gathering, processing and transportation fees and for proceeds from the sale of residue, NGLs and condensate to Anadarko.

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. Additionally, we are exposed to credit risk on the note receivable from Anadarko, which was issued concurrently with the closing of our initial public offering. We are also party to agreements 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 with respect to the assets acquired from Anadarko. Finally, we have entered into various commodity price swap agreements with Anadarko in order to reduce our exposure to commodity price risk and are subject to performance risk thereunder.

Our ability to make distributions to our unitholders may be adversely impacted if Anadarko becomes unable to perform under the terms of our gathering, processing and transportation agreements, natural gas and NGL purchase agreements, Anadarko's note payable to us, our omnibus agreement, the services and secondment agreement, contribution agreements or the commodity price swap agreements.

CONTRACTUAL OBLIGATIONS

Our contractual obligations include, among other things, a revolving credit facility, other third-party long-term debt, capital obligations related to our expansion projects and various operating leases. Refer to Note 8—Debt and Interest Expense and Note 9—Commitments and Contingencies in the Notes to Consolidated Financial Statements under Item 1 of this Form 10-Q for an update to our contractual obligations as of September 30, 2014, including, but not limited to, increases in committed capital.

OFF-BALANCE SHEET ARRANGEMENTS

We do not have any off-balance sheet arrangements other than operating leases. The information pertaining to operating leases required for this item is provided under Note 9—Commitments and Contingencies included in the Notes to Consolidated Financial Statements under Item 1 of this Form 10-Q.

RECENT ACCOUNTING DEVELOPMENTS

Accounting Standards Update ("ASU") 2014-09, Revenue from Contracts with Customers, supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, and industry-specific guidance in Subtopic 932-605, Extractive Activities—Oil and Gas—Revenue Recognition, and requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. This ASU is effective for annual and interim periods beginning in 2017 and is required to be adopted using one of two retrospective application methods, with no early adoption permitted. We are currently evaluating the impact of the adoption of this ASU on our consolidated financial statements.

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ASU 2014-08, Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity, changes the criteria for reporting discontinued operations and requires additional disclosures, both for discontinued operations and for individually significant dispositions and assets classified as held for sale not qualifying as discontinued operations. This ASU is effective for annual and interim periods beginning in 2015, with early adoption permitted for disposals or for assets classified as held for sale that have not been reported in previously issued financial statements. We early adopted this ASU on a prospective basis beginning with the first quarter of 2014. The adoption did not have a material impact on our consolidated financial statements.
ASU 2013-11, Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists, requires that an unrecognized tax benefit, or a portion of an unrecognized tax benefit, be presented in the financial statements as a reduction to a deferred tax asset, except in certain circumstances. This ASU is effective for annual and interim periods beginning in 2014. We adopted this ASU on a prospective basis beginning with the first quarter of 2014. The adoption did not have a material impact on our consolidated financial statements.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity price risk. Certain of our processing services are provided under percent-of-proceeds and keep-whole agreements in which Anadarko is typically responsible for the marketing of the natural gas and NGLs. Under percent-of-proceeds agreements, we receive a specified percentage of the net proceeds from the sale of natural gas and NGLs. Under keep-whole agreements, we keep 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, we compensate the producer for this amount of gas by supplying additional gas or by paying an agreed-upon value for the gas utilized.
To mitigate our exposure to changes in commodity prices as a result of the purchase and sale of natural gas, condensate or NGLs, we currently have in place commodity price swap agreements with Anadarko expiring at various times through December 2016. For additional information on the commodity price swap agreements, see Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Item 1 of this Form 10-Q.
In addition, pursuant to certain of our contracts, we retain and sell drip 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 drip condensate, and our costs for this portion of our contractual arrangement depend on the price of natural gas. Historically, drip condensate sells at a price representing a discount to the price of New York Mercantile Exchange, or NYMEX, West Texas Intermediate crude oil.
We consider our exposure to commodity price risk associated with the above-described arrangements to be minimal given the existence of the commodity price swap agreements with Anadarko and the relatively small amount of our operating income that is impacted by changes in market prices. Accordingly, we do not expect that a 10% increase or decrease in natural gas or NGL prices would have a material impact on our operating income, financial condition or cash flows for the next twelve months, excluding the effect of natural gas imbalances described below.
We bear a limited degree of commodity price risk with respect to settlement of our natural gas imbalances that arise from differences in gas volumes received into our systems and gas volumes delivered by us to customers, as well as instances where our actual liquids recovery or fuel usage varies from the contractually stipulated amounts. Natural gas volumes owed to or by us that are subject to monthly cash settlement are valued according to the terms of the contract as of the balance sheet dates, and generally reflect market index prices. Other natural gas volumes owed to or by us are valued at our weighted average cost of natural gas as of the balance sheet dates and are settled in-kind. Our exposure to the impact of changes in commodity prices on outstanding imbalances depends on the timing of settlement of the imbalances.

Interest rate risk. Interest rates during the nine months ended September 30, 2014, were low compared to historic rates. As of September 30, 2014, we had $170.0 million of outstanding borrowings under our RCF (which bears interest at a rate based on LIBOR or, at our option, an alternative base rate). If interest rates rise, our future financing costs could increase. A 10% change in LIBOR would have resulted in a nominal change in net income and the fair value of the borrowings under the RCF at September 30, 2014.

We may incur additional variable-rate debt in the future, either under our RCF or other financing sources, including commercial bank borrowings or debt issuances.

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Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. The Chief Executive Officer and Chief Financial Officer of the Partnership's general partner performed an evaluation of the Partnership's disclosure controls and procedures as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934 ("Exchange Act"). Our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC, and to ensure that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that the Partnership's disclosure controls and procedures are effective as of September 30, 2014.

Changes in Internal Control Over Financial Reporting. There has been no change in our internal control over financial reporting during the quarter ended September 30, 2014, that has materially affected, or is reasonably likely to materially affect, the Partnership's internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

WGR Operating, LP, a subsidiary of the Partnership, is currently in negotiations with the United States Environmental Protection Agency with respect to alleged non-compliance with the leak detection and repair requirements of the federal Clean Air Act at its Granger, Wyoming facility. Although management cannot predict the outcome of settlement discussions, management believes that it is reasonably likely a resolution of this matter will result in a fine or penalty in excess of $100,000.
Except as discussed above, we are not a party to any legal, regulatory or administrative proceedings other than proceedings arising in the ordinary course of our business. Management believes that there are no such proceedings for which a final disposition could have a material adverse effect on our results of operations, cash flows or financial condition.

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Item 1A. Risk Factors

Security holders and potential investors in our securities should carefully consider the risk factors included below, as well as those set forth under Part I, Item 1A in our Form 10-K for the year ended December 31, 2013, together with all of the other information included in this document, and in our other public filings, press releases, and public discussions with management of the Partnership. Additionally, for a full discussion of the risks associated with Anadarko’s business, see Item 1A under Part I in Anadarko’s Form 10-K for the year ended December 31, 2013, Anadarko’s quarterly reports on Form 10-Q and Anadarko’s other public filings, press releases, and public discussions with Anadarko management. We have identified these risk factors as important factors that could cause our actual results to differ materially from those contained in any written or oral forward-looking statements made by us or on our behalf.

State and local legislative and regulatory initiatives relating to oil and gas operations could adversely affect Anadarko’s and our third-party customers’ production and, therefore, adversely impact our midstream operations.

Certain states in which we operate have adopted, and other states are considering adopting, measures that could impose new or more stringent requirements on oil and gas exploration and production activities. For example, in exchange for the withdrawal of several initiatives relating to hydraulic fracturing and other oil and gas operations proposed for inclusion on the Colorado state ballot in November 2014, the governor of Colorado created the Task Force on State and Local Regulation of Oil and Gas Operations in September 2014 to make recommendations to the state legislature regarding the responsible development of Colorado’s oil and gas resources. Although it is early in the process, it is possible that, as a result of the Task Force’s recommendations, the Colorado state legislature could adopt new policies or legislation relating to oil and gas operations, including measures that would give local governments in Colorado greater authority to limit hydraulic fracturing and other oil and gas operations.
In the event state or local restrictions or prohibitions are adopted in our areas of operations, such as in the Wattenberg field, our customers, including Anadarko, may incur significant compliance costs or may experience delays or curtailment in the pursuit of their exploration, development, or production activities, and possibly be limited or precluded in the drilling of certain wells altogether. Any adverse impact on our customers’ activities would have a corresponding negative impact on our throughput volumes. Accordingly, such restrictions or prohibitions could have a material adverse effect on our business, prospects, results of operations, financial condition, cash flows and ability to make distributions to our unitholders.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

In connection with common units issued through the Continuous Offering Program, our general partner purchased 23,132 general partner units for $1.7 million in cash during the nine months ended September 30, 2014, to maintain its 2.0% general partner interest in us. Proceeds from the Continuous Offering Program, including from the sale of the general partner units, were used for general partnership purposes, including the funding of capital expenditures. The general partner units were issued in reliance on an exemption from registration under Section 4(2) of the Securities Act of 1933, as amended.

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Item 6. Exhibits

Exhibits designated by an asterisk (*) are filed herewith and those designated with asterisks (**) are furnished herewith; all exhibits not so designated are incorporated herein by reference to a prior filing as indicated.

Exhibit Number	Description
2.1#	Contribution, Conveyance and Assumption Agreement by and among Western Gas Partners, LP, Western Gas Holdings, LLC, Anadarko Petroleum Corporation, WGR Holdings, LLC, Western Gas Resources, Inc., WGR Asset Holding Company LLC, Western Gas Operating, LLC and WGR Operating, LP, dated as of May 14, 2008 (incorporated by reference to Exhibit 10.2 to Western Gas Partners, LP's Current Report on Form 8-K filed on May 14, 2008, File No. 001-34046).
2.2#	Contribution Agreement, dated as of November 11, 2008, by and among Western Gas Resources, Inc., WGR Asset Holding Company LLC, WGR Holdings, LLC, Western Gas Holdings, LLC, Western Gas Partners, LP, Western Gas Operating, LLC and WGR Operating, LP. (incorporated by reference to Exhibit 10.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on November 13, 2008, File No. 001-34046).
2.3#	Contribution Agreement, dated as of July 10, 2009, by and among Western Gas Resources, Inc., WGR Asset Holding Company LLC, Anadarko Uintah Midstream, LLC, WGR Holdings, LLC, Western Gas Holdings, LLC, WES GP, Inc., Western Gas Partners, LP, Western Gas Operating, LLC and WGR Operating, LP. (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on July 23, 2009, File No. 001-34046).
2.4#	Contribution Agreement, dated as of January 29, 2010 by and among Western Gas Resources, Inc., WGR Asset Holding Company LLC, Mountain Gas Resources LLC, WGR Holdings, LLC, Western Gas Holdings, LLC, WES GP, Inc., Western Gas Partners, LP, Western Gas Operating, LLC and WGR Operating, LP. (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on February 3, 2010 File No. 001-34046).
2.5#	Contribution Agreement, dated as of July 30, 2010, by and among Western Gas Resources, Inc., WGR Asset Holding Company LLC, WGR Holdings, LLC, Western Gas Holdings, LLC, WES GP, Inc., Western Gas Partners, LP, Western Gas Operating, LLC and WGR Operating, LP. (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on August 5, 2010, File No. 001-34046).
2.6#	Purchase and Sale Agreement, dated as of January 14, 2011, by and among Western Gas Partners, LP, Kerr-McGee Gathering LLC and Encana Oil & Gas (USA) Inc. (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on January 18, 2011 File No. 001-34046).
2.7#	Contribution Agreement, dated as of December 15, 2011, by and among Western Gas Resources, Inc., WGR Asset Holding Company LLC, WGR Holdings, LLC, Western Gas Holdings, LLC, WES GP, Inc., Western Gas Partners, LP, Western Gas Operating, LLC and WGR Operating, LP. (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on December 15, 2011, File No. 001-34046).
2.8#	Contribution Agreement, dated as of February 27, 2013, by and among Anadarko Marcellus Midstream, L.L.C., Western Gas Partners, LP, Western Gas Operating, LLC, WGR Operating, LP, Anadarko Petroleum Corporation and Anadarko E&P Onshore LLC (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on March 5, 2013, File No. 001-34046).
2.9#	Contribution Agreement, dated as of February 27, 2014, by and among WGR Asset Holding Company, LLC, APC Midstream Holdings, LLC, Western Gas Partners, LP, Western Gas Operating, LLC, WGR Operating, LP and Anadarko Petroleum Corporation (incorporated by reference to Exhibit 2.9 to the Annual Report on Form 10-K filed by Western Gas Partners, LP on February 28, 2014, File No. 001-34046).

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Exhibit Number	Description
3.1	Certificate of Limited Partnership of Western Gas Partners, LP (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Registration Statement on Form S-1 filed on October 15, 2007, File No. 333-146700).
3.2	First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated May 14, 2008 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on May 14, 2008, File No. 001-34046).
3.3	Amendment No. 1 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP dated December 19, 2008 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on December 24, 2008, File No. 001-34046).
3.4	Amendment No. 2 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated as of April 15, 2009 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on April 20, 2009, File No. 001-34046).
3.5	Amendment No. 3 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP dated July 22, 2009 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on July 23, 2009, File No. 001-34046).
3.6	Amendment No. 4 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP dated January 29, 2010 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on February 3, 2010, File No. 001-34046).
3.7	Amendment No. 5 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated August 2, 2010 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on August 5, 2010, File No. 001-34046).
3.8	Amendment No. 6 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated July 8, 2011 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on July 8, 2011, File No. 001-34046).
3.9	Amendment No. 7 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated January 13, 2012 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on January 17, 2012, File No. 001-34046).
3.10	Amendment No. 8 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated August 1, 2012 (incorporated by reference to Exhibit 3.10 to Western Gas Partners, LP's Quarterly Report on Form 10-Q filed on August 2, 2012, File No. 001-34046).
3.11	Amendment No. 9 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated December 12, 2012 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on December 12, 2012, File No. 001-34046).
3.12	Amendment No. 10 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated March 1, 2013 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on March 5, 2013, File No. 001-34046).
3.13	Amendment No. 11 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated March 3, 2014 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on March 5, 2014, File No. 001-34046).
3.14	Certificate of Formation of Western Gas Holdings, LLC (incorporated by reference to Exhibit 3.3 to Western Gas Partners, LP's Registration Statement on Form S-1 filed on October 15, 2007, File No. 333-146700).
3.15	Second Amended and Restated Limited Liability Company Agreement of Western Gas Holdings, LLC, dated December 12, 2012 (incorporated by reference to Exhibit 3.2 to Western Gas Partners, LP's Current Report on Form 8-K filed on December 12, 2012, File No. 001-34046).
4.1	Specimen Unit Certificate for the Common Units (incorporated by reference to Exhibit 4.1 to Western Gas Partners, LP's Quarterly Report on Form 10-Q filed on June 13, 2008, File No. 001-34046).

4.2	Indenture, dated as of May 18, 2011, among Western Gas Partners, LP, as Issuer, the Subsidiary Guarantors named therein, as Guarantors, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on May 18, 2011, File No. 001-34046).

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Exhibit Number	Description
4.3	First Supplemental Indenture, dated as of May 18, 2011, among Western Gas Partners, LP, as Issuer, the Subsidiary Guarantors named therein, as Guarantors, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Western Gas Partners, LP's Current Report on Form 8-K filed on May 18, 2011, File No. 001-34046).
4.4	Form of 5.375% Senior Notes due 2021 (incorporated by reference to Exhibit 4.2 to Western Gas Partners, LP's Current Report on Form 8-K filed on May 18, 2011, File No. 001-34046).
4.5	Fifth Supplemental Indenture, dated as of August 14, 2013, among Western Gas Partners, LP, as Issuer, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on August 14, 2013, File No. 001-34046).
4.6	Form of 4.000% Senior Notes due 2022 (incorporated by reference to Exhibit 4.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on June 28, 2012, File No. 001-34046).
4.7	Form of 2.600% Senior Notes due 2018 (incorporated by reference to Exhibit 4.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on August 14, 2013, File No. 001-34046).
4.8	Sixth Supplemental Indenture, dated as of March 20, 2014, among Western Gas Partners, LP, as Issuer, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Western Gas Partners, LP's Current Report on Form 8-K filed on March 20, 2014, File No. 001-34046).
4.9	Form of 5.450% Senior Notes due 2044 (incorporated by reference to Exhibit 4.2 to Western Gas Partners, LP's Current Report on Form 8-K filed on March 20, 2014, File No. 001-34046).
31.1*	Certification of Chief Executive Officer, pursuant to Rule 13a-14(a)/15d-14(a), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer, pursuant to Rule 13a-14(a)/15d-14(a), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certifications of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document
101.LAB*	XBRL Label Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document

Pursuant to Item 601(b)(2) of Regulation S-K, the registrant agrees to furnish supplementally a copy of any omitted schedule to the Securities and Exchange Commission upon request.

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SIGNATURES

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

WESTERN GAS PARTNERS, LP

October 29, 2014

/s/ Donald R. Sinclair
Donald R. Sinclair
President and Chief Executive Officer
Western Gas Holdings, LLC
(as general partner of Western Gas Partners, LP)

October 29, 2014

/s/ Benjamin M. Fink
Benjamin M. Fink
Senior Vice President, Chief Financial Officer and Treasurer
Western Gas Holdings, LLC
(as general partner of Western Gas Partners, LP)