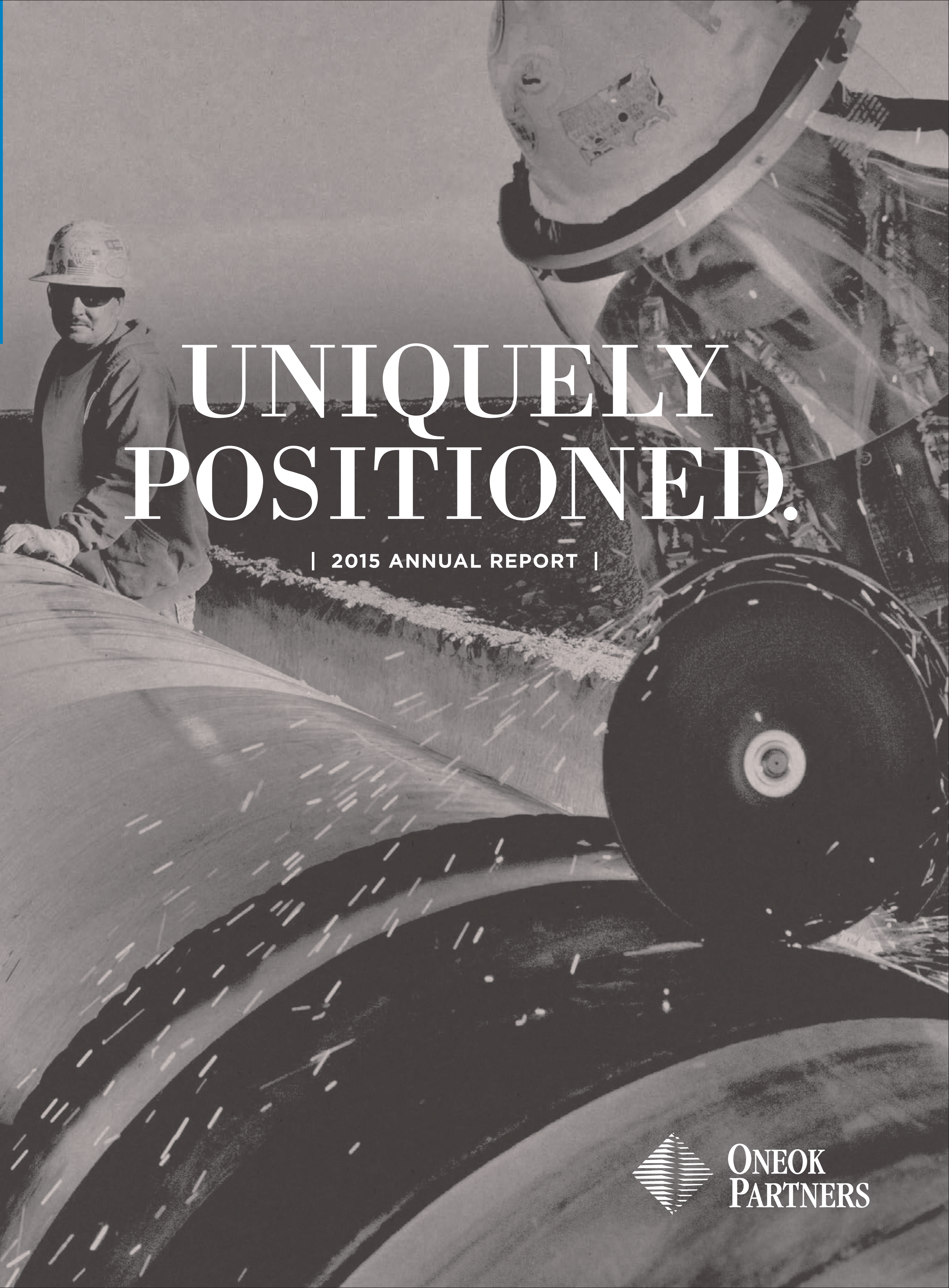


UNIQUELY POSITIONED.

| 2015 ANNUAL REPORT |

ONEOK PARTNERS

ONEOK Partners, L.P. (pronounced ONE-OAK) (NYSE: OKS) is one of the largest publicly traded master limited partnerships in the United States and owns one of the nation's premier natural gas liquids (NGL) systems, connecting NGL supply in the Mid-Continent, Permian and Rocky Mountain regions with key market centers and is a leader in the gathering, processing, storage and transportation of natural gas in the U.S. Its general partner is a wholly owned subsidiary of ONEOK, Inc. (NYSE: OKE), a pure-play publicly traded general partner, which owns 41.2 percent of the overall partnership interest, as of December 31, 2015.

FINANCIAL HIGHLIGHTS

Year Ended December 31

		2015		2014		2013
Consolidated financial information *(millions of dollars)*						
Operating income	$	998.1	$	1,148.8	$	900.7
Net income attributable to ONEOK Partners, L.P.*	$	589.5	$	910.3	$	803.6
Total assets	$	14,927.6	$	14,600.4	$	12,824.2
Capital expenditures (millions of dollars)						
Growth	$	1,070.5	$	1,619.1	$	1,846.8
Maintenance	$	115.6	$	126.9	$	92.5
Total capital expenditures	$	1,186.1	$	1,746.0	$	1,939.3
Common unit data						
Common units outstanding at year-end		212,837,980		180,826,973		159,007,854
Class B units outstanding at year-end		72,988,252		72,988,252		72,988,252
Total units outstanding at year-end		285,826,232		253,815,225		231,996,106
Distributions declared per limited partner unit†	$	3.16	$	3.07	$	2.89
Market price range						
High	$	46.05	$	59.43	$	60.59
Low	$	22.73	$	38.23	$	47.10
Year-end	$	30.13	$	39.63	$	52.65

** Amounts include noncash impairment charges of $264.3 million, or 91 cents per unit, in 2015; and $76.4 million, or 31 cents per unit, in 2014.*

† Distributions declared for the quarter and paid in the following quarter

On the Cover: Construction crews perform work on the Roadrunner Gas Transmission Pipeline in West Texas.

A LETTER TO OUR INVESTORS

UNIQUELY POSITIONED.

WHAT DOES THAT MEAN? *For ONEOK and ONEOK Partners, it's simple. We are able to create value for investors and customers through a uniquely positioned, extensive, integrated network of natural gas and natural gas liquids (NGL) assets.*

As you will read in the following pages, our commitment to creating value guided us through 2015 as we navigated a challenging commodity price environment, and resulted in a strong year-end finish and positive outlook for 2016.

Despite prevailing low commodity prices that led to a lot of uncertainty and volatility in the energy industry and financial markets, ONEOK Partners achieved higher adjusted earnings before interest, taxes, depreciation and amortization (adjusted EBITDA) in 2015, spurred by natural gas and NGL volume growth on our 37,000-mile integrated network of natural gas and NGL assets. In fact, the partnership's 2015 adjusted EBITDA increased slightly compared with 2014 and increased 24 percent since 2013.

In 2015, we achieved this adjusted EBITDA and volume growth by focusing on increasing our fee-based earnings, reducing commodity risk in our business and making prudent financial decisions, while continuing to operate our assets safely, reliably and environmentally responsibly.

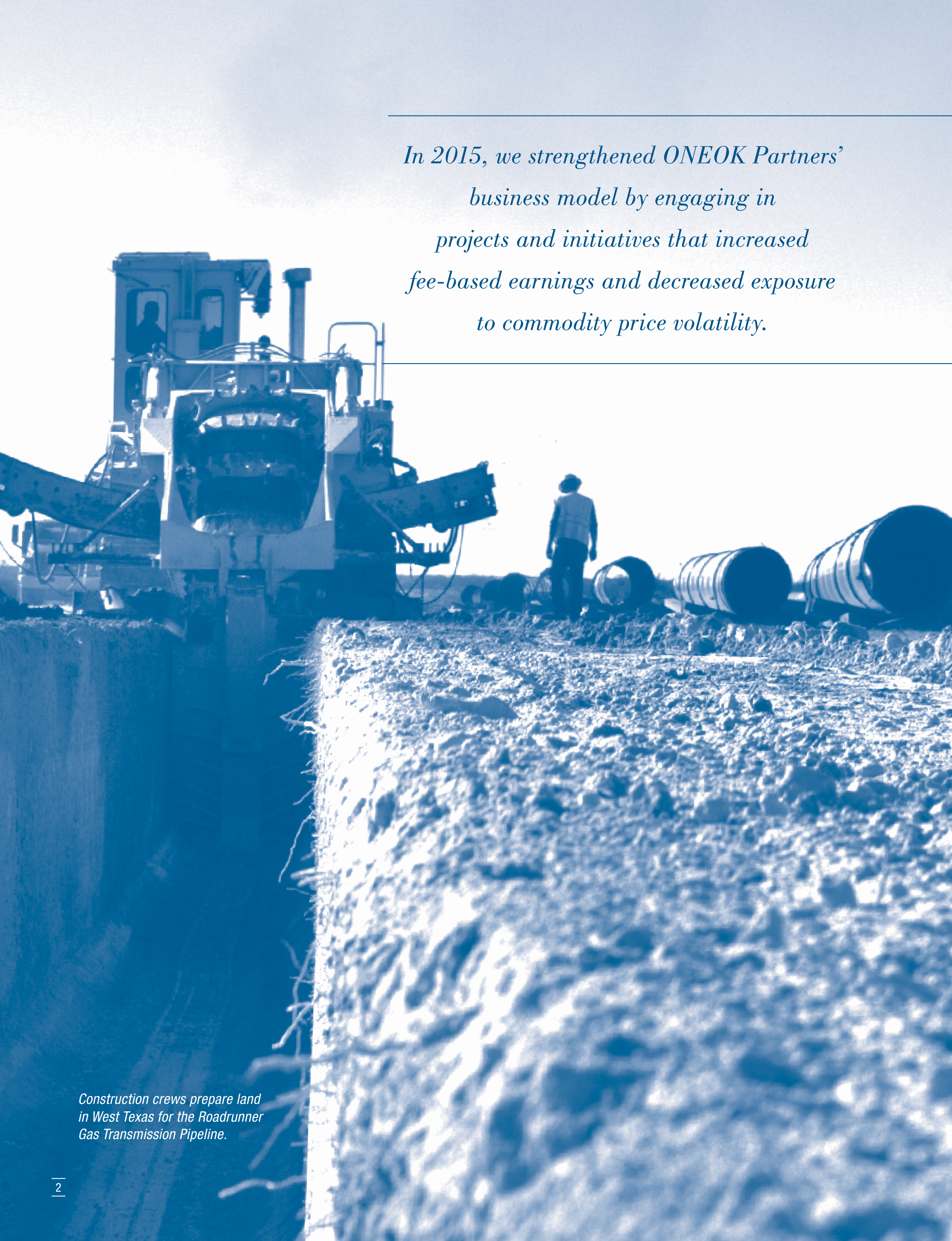
These proactive efforts helped distinguish us from other companies in our industry and resulted in:

- The natural gas liquids segment, one of the largest of its kind in the U.S., finishing 2015 strong with NGL volumes gathered increasing 44 percent, compared with 2014;
- The natural gas pipelines segment continuing to deliver consistent, predominantly fee-based earnings; and
- The natural gas gathering and processing segment recording its highest volumes ever in the fourth quarter 2015, and 2015 natural gas volumes gathered and processed increasing approximately 12 and 10 percent, respectively, compared with 2014.

ONEOK Partners finished 2015 strong and is well-positioned in these challenging times to grow earnings in 2016 and beyond.

Similarly, ONEOK ended 2015 in a strong financial position, due largely to increased cash distributions from ONEOK's limited and general partner interests in ONEOK Partners. Distributions declared from the partnership increased more than 16 percent in 2015 compared with 2014, driven by ONEOK's purchase of an additional 21.5 million ONEOK Partners units in August 2015.

In 2015, we strengthened ONEOK Partners' business model by engaging in projects and initiatives that increased fee-based earnings and decreased exposure to commodity price volatility.



Construction crews prepare land in West Texas for the Roadrunner Gas Transmission Pipeline.

STRENGTHENING OUR POSITION

In challenging times, we rely on our strengths, which for the partnership are our predominantly fee-based structure and uniquely positioned, integrated network of natural gas and NGL assets that allow us to provide nondiscretionary services to our customers from North Dakota to the Texas Gulf Coast.

In 2015, we strengthened ONEOK Partners' business model by engaging in projects and initiatives that increased fee-based earnings and decreased exposure to commodity price volatility. Contract restructuring in our natural gas gathering and processing segment resulted in increased fee-based earnings, providing a contract mix that we expect will be greater than 75 percent fee-based in 2016 – *up from 44 percent in 2015.* The average fee rate in this segment increased to 55 cents in the fourth quarter 2015, compared with 36 cents in the fourth quarter 2014.

Companywide, we anticipate our 2016 fee-based earnings will increase to approximately 85 percent from 66 percent in 2014, which we expect will positively impact our full-year 2016 earnings.

These restructuring efforts made our business model more durable and sustainable than before, while also enabling us to continue providing the nondiscretionary services and critical infrastructure that our customers need.

NATURAL GAS LIQUIDS: CAPITALIZING ON OUR POSITION

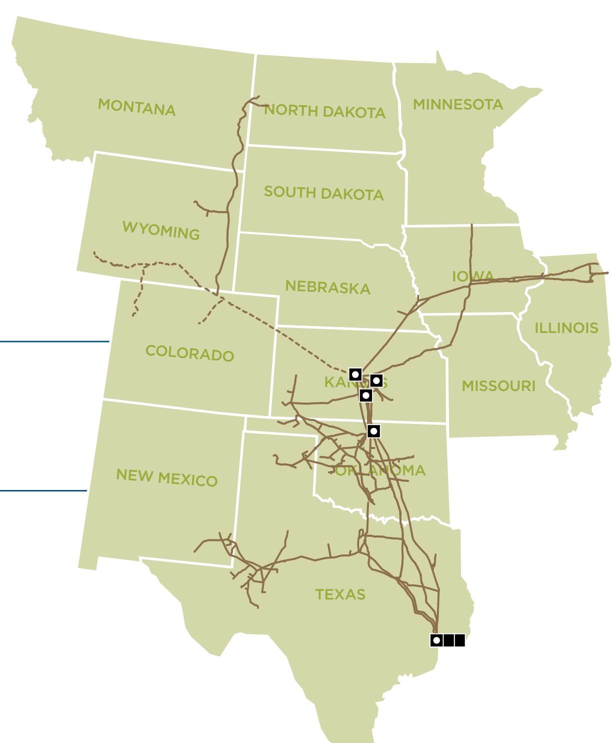
Our unique asset position in key NGL-rich plays and flexible, nondiscretionary, fee-based services continue to drive success in our extensive natural gas liquids business, which is the second-largest in the country. Capitalizing on largely fee-based exchange, storage and transportation services, this segment provides unique transportation and fractionation capabilities to major markets.

Systemwide, we connected eight new natural gas processing plants to our NGL system in 2015 and expect an additional four third-party plant connections in 2016, which will bring our total to more than 180 processing plant connections in the Mid-Continent, Barnett Shale, Rocky Mountain region and Permian Basin.

We continue to benefit from our extensive position in the Williston Basin, where our Bakken NGL Pipeline provides transportation takeaway from the region.

NATURAL GAS LIQUIDS

NGL Pipelines
NGL Fractionator
NGL Storage
50 percent interest



Added de-ethanization facilities at our Stateline natural gas processing plants in Williams County, North Dakota, will produce an expected 26,000 barrels per day (bpd) of ethane to be delivered to a third-party pipeline to serve markets in Canada. These de-ethanization facilities are expected to be completed in the third quarter 2016.

We also continue to benefit from our 2014 acquisition of the West Texas LPG Pipeline system, which established an NGL presence in the Permian Basin and added 2,600 miles of gathering pipelines with a gross capacity of 285,000 bpd to our system.

As we look forward to 2016 and beyond, a significant opportunity is emerging for our natural gas liquids segment as we serve the growing petrochemical demand for ethane, another NGL.

The competitive pricing of ethane is leading to increased exports, as well as the construction of additional world-class petrochemical facilities on the Gulf Coast that will utilize ethane as a feedstock during the manufacturing process.

We anticipate that basins closest to market hubs will be the first to recover ethane, and our NGL assets in and around these areas are ideally positioned to serve this growing U.S. demand, which is expected to accelerate in 2017.

This is particularly true because approximately one-third of the incremental ethane supply sources needed to serve this demand are connected to our NGL system for transportation and fractionation services that will serve the new petrochemical plants.

We expect the impact of the increased ethane demand on our NGL throughput to begin in 2017.

NATURAL GAS PIPELINES: DIVERSIFYING OUR POSITION

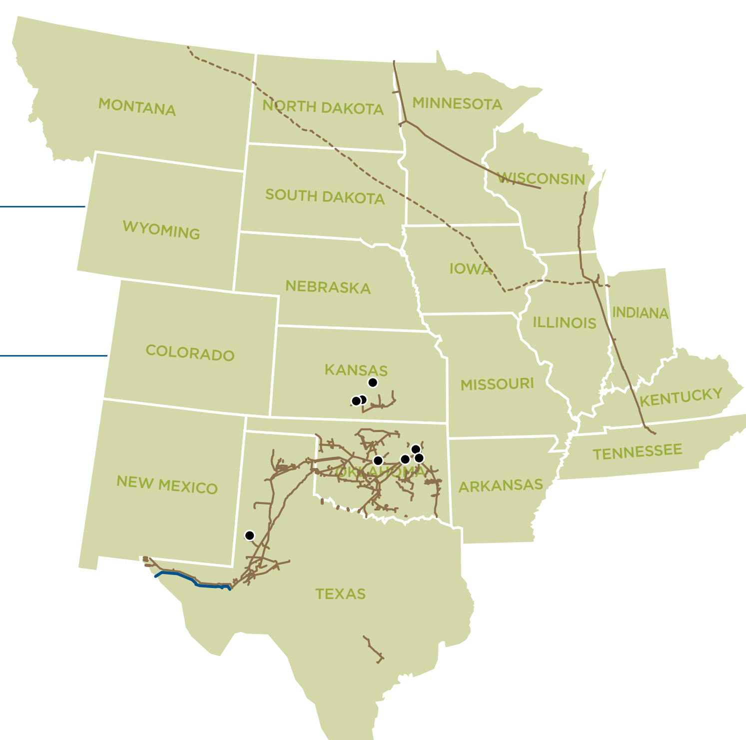
In 2015, we diversified our asset mix through key growth projects in the Permian Basin that enhanced our fee-based portfolio and will connect us to emerging markets. These projects included:

- **ROADRUNNER GAS TRANSMISSION PIPELINE**
  Roadrunner is a 200-mile pipeline that connects our WesTex natural gas pipeline system near Coyanosa, Texas, to a new international border-crossing connection at the U.S. and Mexico border near San Elizario, Texas.

  The project is a 50-50 joint venture with Mexico City-based natural gas infrastructure company

NATURAL GAS PIPELINES

- Natural Gas Pipelines
- Natural Gas Storage
- 50 percent interest
- Roadrunner



Fermaca. The project will be completed in phases – the first phase was placed in service in March 2016 providing 170 million cubic feet per day (MMcf/d) of capacity. The second phase is expected to increase the pipeline's capacity to 570 MMcf/d and to be completed in the first quarter 2017. The third and final phase of the project is expected to be completed in 2019 and to increase the total capacity of the pipeline to 640 MMcf/d.

The initial design capacity of Roadrunner is fully subscribed and supported by 25-year, take-or-pay transportation agreements.

- **WESTEX PIPELINE EXPANSION**

  The expansion of this intrastate natural gas pipeline system is expected to add approximately 260 MMcf/d of capacity to our system by 2017.

  The total capacity is 90 percent subscribed with 25-year, take-or-pay transportation agreements.

Together, these projects provide markets in Mexico access to upstream supply basins in West Texas and the Mid-Continent, which adds location and price diversity to their supply mix, while increasing the natural gas pipelines business' fee-based earnings.

NATURAL GAS GATHERING AND PROCESSING: ENHANCING OUR POSITION

Our strong natural gas gathering and processing position in high-producing crude oil and NGL-rich resource plays, like the Williston Basin, continues to drive volume growth.

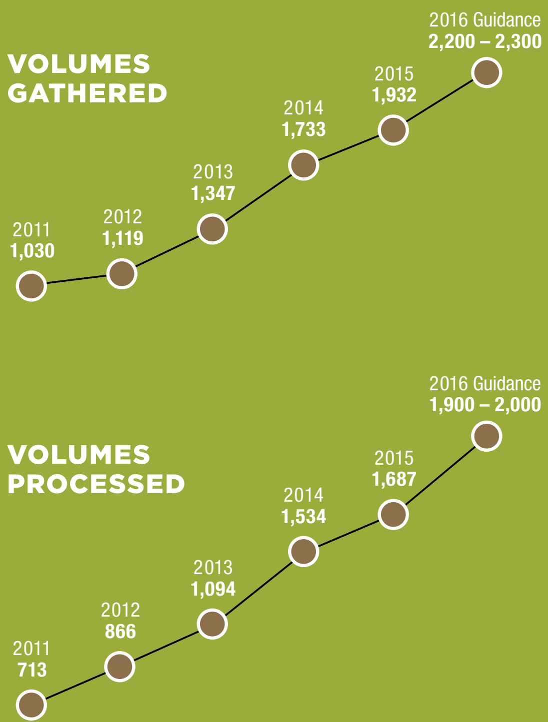
Our Williston Basin assets are uniquely positioned to capture growing volumes from:

- New well connections;
- A substantial backlog of wells drilled but not completed; and
- An inventory of natural gas currently flaring.

An employee monitors natural gas flow at a facility in West Texas.

NATURAL GAS VOLUME GROWTH

Billion British thermal units per day (BBtu/d)



NATURAL GAS GATHERING AND PROCESSING

Natural gas production in core areas has historically exceeded the capacity of existing natural gas processing infrastructure causing natural gas to be flared by oil producers in many cases.

To capture and process these volumes, we continue to invest in critical infrastructure, including:

- **LONESOME CREEK PLANT**
  A 200-MMcf/d natural gas processing facility in McKenzie County, North Dakota; *Completed November 2015*
- **NATURAL GAS COMPRESSION INFRASTRUCTURE**
  Added approximately 100 MMcf/d of natural gas processing capacity; *Completed December 2015*
- **BEAR CREEK PLANT**
  An 80-MMcf/d natural gas processing plant in Dunn County, North Dakota; *Expected completion: third quarter 2016*

The completion of Lonesome Creek and the natural gas compression infrastructure increased our total natural gas processing capacity in the Williston Basin to approximately 900 MMcf/d and alleviated field constraints in the basin.

ONEOK'S 2015 FINANCIAL PERFORMANCE AND 2016 GUIDANCE

At ONEOK, 2015 cash flow available for dividends was $641 million, driven by increased distributions from approximately 21.5 million common units we purchased for approximately $650 million in a private placement from ONEOK Partners in August 2015. This was part of a $750 million offering by ONEOK Partners to meet the partnership's equity needs and increased ONEOK's aggregate ownership interest to 41.2 percent from 36.8 percent.

ONEOK's dividend coverage ratio was 1.29 times in the fourth quarter 2015, which we achieved through increased distributions from our limited and general partner interests in ONEOK Partners.

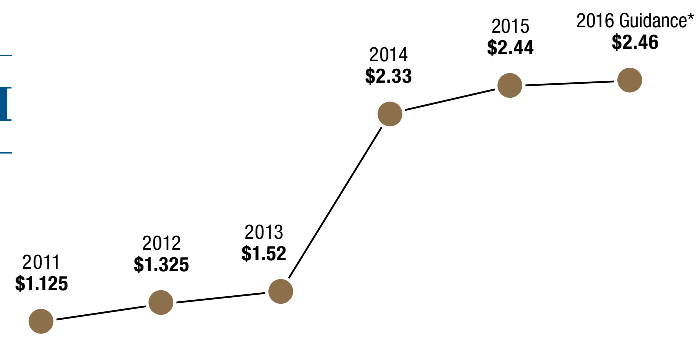
ONEOK expects to generate $160 million of free cash flow after dividends in 2016, which along with $90 million of cash on hand and an unutilitized $300 million credit facility provides ONEOK with significant flexibility to support ONEOK Partners, if needed.

ONEOK expects to have a dividend coverage ratio of 1.3 times in 2016 and no long-term debt maturities until 2022.

ONEOK has a long history of prudent financial decision-making, and we will continue to make decisions that are in the best long-term interest of our investors at both ONEOK and ONEOK Partners.

DIVIDEND GROWTH

ONEOK annual dividends declared per share (split adjusted)
** Pending ONEOK board approval*



Construction at the Lonesome Creek natural gas processing facility in McKenzie County, North Dakota

An employee closes a valve at our West Texas LPG natural gas liquids pipeline assets near Big Spring, Texas.

ONEOK PARTNERS' 2015 FINANCIAL PERFORMANCE AND 2016 GUIDANCE

In 2015, ONEOK Partners' adjusted EBITDA was $1.57 billion, a slight increase compared with 2014.

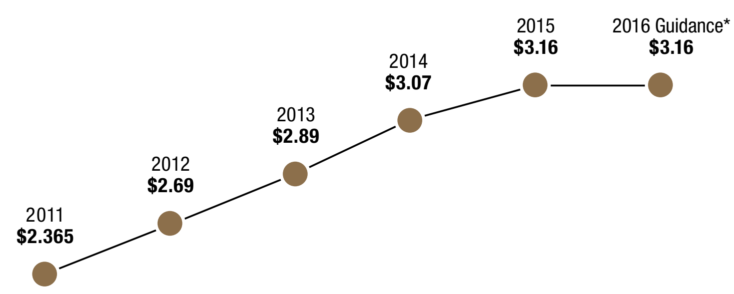
ONEOK Partners' distribution coverage ratio was 1.03 times in the fourth quarter 2015, which we achieved by processing higher volumes and increasing fee-based earnings.

In January 2016, the partnership entered into a $1 billion three-year unsecured term loan agreement that effectively refinanced 2016 long-term debt maturities and further enhanced financial flexibility, providing ample liquidity to fund capital-growth projects. We also expect this to eliminate the need to access public markets for debt and equity until well into 2017.

Looking forward, we expect ONEOK Partners' 2016 earnings to increase compared with 2015, primarily from volume growth and enhanced fee-based earnings, resulting in increased distributable cash flow.

DISTRIBUTION GROWTH

ONEOK Partners annual distributions declared per unit (split adjusted)
** Pending ONEOK Partners board approval*



The partnership expects to maintain our investment-grade credit ratings, sustain our current distribution and achieve distribution coverage of 1.0 times or better for 2016. We also expect to maintain our solid balance sheet and ample liquidity, which includes access to our commercial paper program and $2.4 billion credit facility.

OUR THANKS

Our achievements in this challenging environment would not have been possible without the tremendous contributions of our many employees, whose efforts to operate our network of assets safely, reliably and environmentally responsibly have enabled us to continue to provide quality and reliable service to our customers. Their hard work and commitment delivered solid results for the company, our customers and you, our investors. We thank them for their continued dedication.

Amid many headwinds, we executed well in 2015 and enter 2016 well positioned to continue to strengthen our unique asset position and reinforce our balance sheets at both ONEOK and ONEOK Partners.

As always, thank you for your continued trust and investment in ONEOK and ONEOK Partners.

JOHN W. GIBSON
Chairman

TERRY K. SPENCER
President and Chief Executive Officer

March 9, 2016

UPDATES TO THE BOARDS OF DIRECTORS

The ONEOK and ONEOK Partners boards of directors are actively involved in overseeing, reviewing and guiding our corporate strategies and play an important role in providing governance oversight.

In December 2015, the ONEOK board of directors elected three new board members, whose experience and expertise will greatly benefit the company, its board and its shareholders.

- **BRIAN L. DERKSEN** served as global deputy chief executive officer of Deloitte Touche Tohmatsu Limited from 2011 until 2014, and as deputy chief executive officer of Deloitte U.S. from 2003 to 2011. Prior to that, he was U.S. managing partner of the financial advisory business unit of Deloitte U.S. and regional managing partner of the mid-America region of Deloitte U.S.

- **RANDALL J. LARSON** served as chief executive officer of the general partner of TransMontaigne Partners L.P. from 2006 until 2009, chief financial officer from 2003 to 2006, and controller from 2002 to 2003.

- **KEVIN S. MCCARTHY** is co-founder and managing partner for Kayne Anderson Fund Advisors. He is responsible for master limited partnership private equity investments and serves as chairman, president and chief executive officer of the Kayne Anderson MLP Investment Company (KYN), Kayne Anderson Energy Total Return Fund (KYE), Kayne Anderson Midstream/Energy Fund (KMF) and Kayne Anderson Energy Development Company (KED).

With these elections, the ONEOK board of directors now has 12 members, 10 of whom are independent.

William L. Ford retired from the board in December 2015 after 34 years of exceptional leadership and guidance.

Bert H. Mackie retired from the board in May 2015 after 26 years of wise counsel and dedicated service.

James C. Day will retire from the board in May 2016 after 12 years of invaluable leadership and direction.

In April 2015, the ONEOK Partners board of directors elected one new board member, who adds a wealth of accounting, finance and master limited partnership knowledge to the board and unitholders.

- **MICHAEL G. HUTCHINSON** retired as a partner of Deloitte & Touche in 2012 after nearly 35 years with the firm. During his Deloitte career, he led the energy and natural resources practice in Colorado for more than 10 years while also managing more than 150 people in the Denver, Colorado, audit and enterprise risk management practice.

With the addition of Hutchinson, the ONEOK Partners board now has eight members, six of whom are independent.

Gil J. Van Lunsen retired from the board in April 2015 after 10 years of loyal support and exceptional leadership.

Ford, Mackie, Day and Lunsen retired or will retire after reaching the mandatory retirement age for ONEOK and ONEOK Partners board members.

CORPORATE INFORMATION

ONEOK Annual Meeting
The 2016 annual meeting of shareholders will be held Wednesday, May 25, 2016, at 9 a.m. Central Daylight Time at ONEOK Plaza, 100 West Fifth Street, Tulsa, OK.

Auditors
PricewaterhouseCoopers LLP
Two Warren Place
6120 South Yale Avenue, Suite 1850
Tulsa, OK 74136

Direct Stock Purchase and Dividend Reinvestment Plan
ONEOK's Direct Stock Purchase and Dividend Reinvestment Plan provides investors the opportunity to purchase shares of common stock without payment of any brokerage fees or service charges and to reinvest dividends automatically.

Transfer Agent, Registrar, Dividend-paying Agent and Distribution-paying Agent
Wells Fargo Shareowner Services
P.O. Box 64874
St. Paul, MN 55164-0854
ONEOK: 866-235-0232 ONEOK Partners: 866-605-8639
www.shareowneronline.com

Tax Package Support
ONEOK Partners, L.P.
K-1 Support
P.O. Box 799060
Dallas, TX 75379-9060
800-371-2188
www.taxpackagesupport.com/oneok

Credit Ratings	OKE	OKS
Standard & Poor's	BB+ (negative)	BBB (negative)
Moody's Investors Service	Ba1 (stable)	Baa2 (negative)

Investor Relations
T.D. Eureste, *director – investor relations,* by phone at 918-588-7167 or by email at teureste@oneok.com.

Megan Lewis, *senior investor relations consultant,* by phone at 918-561-5325 or by email at mlewis@oneok.com.

Corporate Websites
www.oneok.com www.oneokpartners.com

NON-GAAP (GENERALLY ACCEPTED ACCOUNTING PRINCIPLES) FINANCIAL MEASURES

ONEOK and ONEOK Partners have disclosed in this annual report expected 2016 cash flow available for dividends, free cash flow, dividend coverage ratio, adjusted EBITDA, distributable cash flow and cash distribution coverage ratio, which are non-GAAP financial metrics, used to measure ONEOK's and ONEOK Partners' financial performance, and are defined as follows:

- Cash flow available for dividends is defined as net income less the portion attributable to non-controlling interests, adjusted for equity in earnings and distributions declared from ONEOK Partners, and ONEOK's stand-alone depreciation and amortization, deferred income taxes, stand-alone capital expenditures and certain other items;
- Free cash flow is defined as cash flow available for dividends, computed as described above, less ONEOK's dividends declared;
- Dividend coverage ratio is defined as cash flow available for dividends divided by the dividends declared for the period;
- Adjusted EBITDA is defined as net income adjusted for interest expense, depreciation and amortization, impairment charges, income taxes and allowance for equity funds used during construction and certain other noncash items;
- Distributable cash flow is defined as adjusted EBITDA, computed as described above, less interest expense, maintenance capital expenditures and equity earnings from investments, excluding noncash impairment charges, adjusted for cash distributions received and certain other items; and
- Cash distribution coverage ratio is defined as distributable cash flow to limited partners per limited partner unit divided by the distribution declared per limited partner unit for the period.

These non-GAAP financial measures described above are useful to investors because they are used by many companies in the industry as a measurement of financial performance and are commonly employed by financial analysts and others to evaluate our financial performance and to compare our financial performance with the performance of other companies within our industry. Cash flow available for dividends, free cash flow, dividend coverage ratio, adjusted EBITDA, distributable cash flow and cash distribution coverage ratio should not be considered in isolation or as a substitute for net income or any other measure of financial performance presented in accordance with GAAP.

These non-GAAP financial measures exclude some, but not all, items that affect net income. Additionally, these calculations may not be comparable with similarly titled measures of other companies. Furthermore, these non-GAAP measures should not be viewed as indicative of the actual amount of cash that is available for dividends or distributions or that is planned to be distributed in a given period, nor do they equate to available cash as defined in the partnership agreement.

FORWARD-LOOKING STATEMENTS

The statements in this annual report that are not historical information, including statements concerning plans and objectives of management for future operations, economic performance or related assumptions, are forward-looking statements. Forward-looking statements may include words such as "anticipate," "estimate," "expect," "project," "intend," "plan," "believe," "should," "goal," "forecast," "guidance," "could," "may," "continue," "might," "potential," "scheduled" and other words and terms of similar meaning.

Although we believe that our expectations regarding future events are based on reasonable assumptions, we can give no assurance that such expectations or assumptions will be achieved. Important factors that could cause actual results to differ materially from those in the forward-looking statements are described under Part I, Item 1A, Risk Factors and Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation and "Forward-Looking Statements" in the ONEOK, Inc. and ONEOK Partners, L.P. Annual Reports on Form 10-K for the year ended December 31, 2015, included in this annual report.

All references in this report to financial guidance are based on news releases issued on December 21, 2015, and February 22, 2016, and are not being updated or affirmed by this report.

ONEOK'S CASH FLOW AVAILABLE FOR DIVIDENDS – UNAUDITED *(millions of dollars)*

	2015	2014
Distributions from ONEOK Partners – declared	$ 735.3	$ 633.0
Interest expense, excluding noncash items	(77.9)	(68.7)
Cash income taxes	-	-
Released contracts from the former Energy Services segment	(34.3)	47.5
Corporate expenses	(6.9)	(7.5)
Equity compensation reimbursed by ONEOK Partners	27.3	31.3
Cash flows from ONE Gas separation	-	(5.7)
Total cash flows	643.5	629.9
Capital expenditures	(2.2)	(9.3)
Cash flow available for dividends	641.3	620.6
Dividends declared	(510.5)	(484.9)
Free cash flow	$ 130.8	$ 135.7
Dividend coverage ratio	1.26	1.28

RECONCILIATION OF ONEOK'S CASH FLOW AVAILABLE FOR DIVIDENDS AND FREE CASH FLOW TO NET INCOME – UNAUDITED *(millions of dollars)*

	2015	2014
Net income attributable to ONEOK	$ 245.0	$ 314.1
Depreciation and amortization	2.4	14.8
Deferred income taxes	133.0	141.4
Equity in earnings of ONEOK Partners	(463.7)	(563.3)
Distributions from ONEOK Partners – declared	735.3	633.0
Equity compensation reimbursed by ONEOK Partners	27.3	31.3
Energy Services realized working capital	(38.7)	63.4
Other	2.9	(4.8)
Total cash flow	643.5	629.9
Capital expenditures	(2.2)	(9.3)
Cash flow available for dividends	641.3	620.6
Dividends declared	(510.5)	(484.9)
Free cash flow	$ 130.8	$ 135.7

RECONCILIATION OF ONEOK PARTNERS' NET INCOME TO ADJUSTED EBITDA AND DISTRIBUTABLE CASH FLOW – UNAUDITED *(millions of dollars)*

	2015	2014	2013
Net income	$ 597.9	$ 911.3	$ 803.9
Interest expense	338.9	281.9	236.7
Depreciation and amortization	352.2	291.2	236.7
Impairment charges	264.3	76.4	-
Income taxes	4.1	12.7	10.9
Allowance for equity funds used during construction and other noncash items	8.1	(14.9)	(30.5)
Adjusted EBITDA	1,565.5	1,558.6	1,257.7
Interest expense	(338.9)	(281.9)	(236.7)
Maintenance capital	(115.6)	(126.9)	(92.4)
Equity earnings from investments, excluding noncash impairment charges	(125.3)	(117.4)	(110.5)
Distributions received from unconsolidated affiliates	155.9	139.0	137.5
Other	(4.7)	(2.0)	(6.4)
Distributable cash flow	$ 1,136.7	$ 1,169.4	$ 949.2

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

FORM 10-K

X ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2015.
OR
__ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from __________ to __________.

Commission file number **1-12202**

ONEOK PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**93-1120873**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
100 West Fifth Street, Tulsa, OK	**74103**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code **(918) 588-7000**

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

Common units	**New York Stock Exchange**
(Title of each class)	(Name of each exchange on which registered)

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes X No__.

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, 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 X No __

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Registration S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. X

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

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

Aggregate market value of the common units held by non-affiliates based on the closing trade price on June 30, 2015, was $5.7 billion.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date.

Class	Outstanding at February 16, 2016
Common units	212,837,980 units
Class B units	72,988,252 units

DOCUMENTS INCORPORATED BY REFERENCE: None.

ONEOK PARTNERS, L.P.
2015 ANNUAL REPORT

As used in this Annual Report, references to "we," "our," "us" or the "Partnership" refer to ONEOK Partners, L.P., its subsidiary, ONEOK Partners Intermediate Limited Partnership, and its subsidiaries, unless the context indicates otherwise.

GLOSSARY

The abbreviations, acronyms and industry terminology used in this Annual Report are defined as follows:

AFUDC	Allowance for funds used during construction
Annual Report	Annual Report on Form 10-K for the year ended December 31, 2015
ASU	Accounting Standards Update
Bbl	Barrels, 1 barrel is equivalent to 42 United States gallons
BBtu/d	Billion British thermal units per day
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
CFTC	U.S. Commodity Futures Trading Commission
Clean Air Act	Federal Clean Air Act, as amended
Clean Water Act	Federal Water Pollution Control Act Amendments of 1972, as amended
DOT	United States Department of Transportation
EBITDA	Earnings before interest expense, income taxes, depreciation and amortization
EPA	United States Environmental Protection Agency
Exchange Act	Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	Accounting principles generally accepted in the United States of America
GHG	Greenhouse gas
Intermediate Partnership	ONEOK Partners Intermediate Limited Partnership, a wholly owned subsidiary of ONEOK Partners, L.P.
IRS	Internal Revenue Service
KCC	Kansas Corporation Commission
LIBOR	London Interbank Offered Rate
MBbl	Thousand barrels
MBbl/d	Thousand barrels per day
MDth/d	Thousand dekatherms per day
MMBbl	Million barrels
MMBtu	Million British thermal units
MMcf/d	Million cubic feet per day
Moody's	Moody's Investors Service, Inc.
Natural Gas Act	Natural Gas Act of 1938, as amended
Natural Gas Policy Act	Natural Gas Policy Act of 1978, as amended
NGL(s)	Natural gas liquid(s)
NGL products	Marketable natural gas liquid purity products, such as ethane, ethane/propane mix, propane, iso-butane, normal butane and natural gasoline
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
OCC	Oklahoma Corporation Commission
ONE Gas	ONE Gas, Inc.
ONEOK	ONEOK, Inc.
ONEOK Partners	ONEOK Partners, L.P.
ONEOK Partners GP	ONEOK Partners GP, L.L.C., a wholly owned subsidiary of ONEOK and the sole general partner of ONEOK Partners
OPIS	Oil Price Information Service
OSHA	Occupational Safety and Health Administration
Partnership Agreement	Third Amended and Restated Agreement of Limited Partnership of ONEOK Partners, L.P., as amended
Partnership Credit Agreement	The Partnership's $2.4 billion amended and restated revolving credit agreement effective as of January 31, 2014, as amended
PHMSA	United States Department of Transportation Pipeline and Hazardous Materials Safety Administration
POP	Percent of Proceeds

Quarterly Report(s)	Quarterly Report(s) on Form 10-Q
Roadrunner	Roadrunner Gas Transmission, LLC
RRC	Railroad Commission of Texas
S&P	Standard & Poor’s Rating Services
SCOOP	South Central Oklahoma Oil Province
SEC	Securities and Exchange Commission
Securities Act	Securities Act of 1933, as amended
Term Loan Agreement	The Partnership’s senior unsecured delayed-draw three-year $1.0 billion term loan agreement dated January 8, 2016
West Texas LPG	West Texas LPG Pipeline Limited Partnership and Mesquite Pipeline
WTI	West Texas Intermediate
WTLPG	West Texas LPG Pipeline Limited Partnership
XBRL	eXtensible Business Reporting Language

The statements in this Annual Report that are not historical information, including statements concerning plans and objectives of management for future operations, economic performance or related assumptions, are forward-looking statements. Forward-looking statements may include words such as “anticipate,” “estimate,” “expect,” “project,” “intend,” “plan,” “believe,” “should,” “goal,” “forecast,” “guidance,” “could,” “may,” “continue,” “might,” “potential,” “scheduled” and other words and terms of similar meaning. Although we believe that our expectations regarding future events are based on reasonable assumptions, we can give no assurance that such expectations or assumptions will be achieved. Important factors that could cause actual results to differ materially from those in the forward-looking statements are described under Part I, Item 1A, Risk Factors, and Part II, Item 7, Management’s Discussion and Analysis of Financial Condition and Results of Operations and “Forward-Looking Statements,” in this Annual Report.

PART I

ITEM 1. BUSINESS

GENERAL

ONEOK Partners, L.P. is a publicly traded master limited partnership, organized under the laws of the state of Delaware, that was formed in 1993. Our common units are listed on the NYSE under the trading symbol "OKS." We are one of the largest publicly traded master limited partnerships and a leader in the gathering, processing, storage and transportation of natural gas in the United States. In addition, we own one of the nation's premier natural gas liquids systems, connecting NGL supply in the Mid-Continent, Permian and Rocky Mountain regions with key market centers. We apply our core capabilities of gathering, processing, fractionating, transporting, storing and marketing natural gas and NGLs through the rebundling of services across the value chains through vertical integration in an effort to provide our customers with premium services at lower costs.

EXECUTIVE SUMMARY

Commodity Price Environment - Due in part to the rapid growth in crude oil and natural gas production in the United States, the global supply of crude oil and natural gas exceeded demand and led to a dramatic fall in commodity prices beginning in the fourth quarter 2014. Lower crude oil and natural gas prices persisted throughout 2015 and are expected to remain low in 2016. The production growth and decline in crude oil prices have also contributed to lower NGL product prices, as well as narrow NGL product price differentials.

WTI crude oil prices declined to an average of approximately $50.00 per barrel in 2015, compared with prices averaging approximately $93.00 per barrel in 2014. NYMEX natural gas prices also declined to an average of approximately $2.60 per MMBtu in 2015, compared with prices averaging approximately $4.30 per MMBtu in 2014. OPIS Conway propane prices averaged less than $0.41 per gallon in 2015, compared with prices averaging more than $1.10 per gallon in 2014. At December 31, 2015, prices for WTI crude oil, NYMEX natural gas and OPIS Conway propane declined to approximately $35.00 per barrel, $2.30 per MMBtu and $0.33 per gallon, respectively, and remained weak into early 2016.

We have mitigated partially our exposure to the current commodity price environment by growing our fee-based business. We have a predominantly fee-based business in our Natural Gas Liquids and Natural Gas Pipelines segments and, historically to a lesser extent, in our Natural Gas Gathering and Processing segment. In 2015, however, our Natural Gas Gathering and Processing segment restructured many POP with fee contracts associated with a significant amount of our gathered volumes to increase the fee-based component and will continue to seek opportunities to similarly restructure additional contracts in 2016. These restructured contracts favorably impacted our 2015 results, and we expect to receive the full benefit of the improved earnings from these contracts in our 2016 financial results. In the fourth quarter 2015, our Natural Gas Gathering and Processing segment's fee revenues averaged $0.55 per MMBtu, compared with an average of $0.36 per MMBtu in 2014. As a result of these restructured contracts, we expect our Natural Gas Gathering and Processing segment's fee-based earnings to increase significantly to more than 75 percent in 2016 and our consolidated fee-based earnings to increase to approximately 85 percent in 2016. To further mitigate the impact of lower commodity prices, we have hedged a significant portion of our Natural Gas Gathering and Processing segment's expected equity volumes for 2016 and 2017. Our Natural Gas Liquids and Natural Gas Pipelines segments continue to provide primarily fee-based services, and many of the contracts in these segments include fixed fee, minimum volume or firm demand charge agreements that provide a minimum level of revenues regardless of commodity prices or volumetric throughput.

The current weakened commodity price environment, resulting from factors beyond our control, is creating challenges for our crude oil and natural gas producer customers and resulted in decreased drilling activity in 2015, compared with 2014. In the Williston Basin, the number of rigs drilling on acreage dedicated to us decreased from approximately 80 rigs in January 2015 to approximately 30 rigs in December 2015. Despite the sustained lower crude oil, natural gas and NGL prices and reduced capital spending by producers, we continue to expect demand for midstream services and infrastructure development to be driven by producers who need to connect production with end-use markets where current infrastructure is insufficient or nonexistent. Our natural gas and NGL volumes increased in 2015, particularly in the Williston Basin, as producers are focusing their drilling in the most productive areas and are using more efficient drilling and completion techniques. We expect this lower commodity price environment to continue in 2016, which will impact our net realized prices for natural gas, NGLs and condensate, as well as our financial results. If the low commodity price environment persists for a prolonged period or prices decline further, volumes across our assets may grow more slowly than in the past or decline.

In the future, we expect commodity prices to recover; however, the timing of this recovery is uncertain. We do not expect commodity prices to return in the near term to the levels experienced in the first half of 2014.

Supply - Natural gas and NGL supply is affected by producer drilling activity, which is sensitive to commodity prices, operating capacity, access to capital and regulatory control. Crude oil and natural gas price declines have continued since 2014, which has resulted in fewer active drilling rigs within our areas of operations. Although drilling has slowed, many of our customers continue to drill new wells in the most productive areas, and improvements in drilling and completion technology are resulting in higher volumes from the wells that are completed. These new technologies, such as multi-well pads and more efficient drilling rigs, are resulting in lower drilling and completion costs, which are mitigating partially the lower commodity prices for our producer customers. In addition, new wells drilled using horizontal drilling technologies tend to produce volumes at higher initial production rates resulting generally in higher initial decline rates than conventional vertical wells; however, the decline rates flatten out over time. A significant portion of our Williston Basin gathering and processing assets are in the most productive areas, which typically produce at higher initial production rates compared with other areas, have the highest natural gas content and have slower natural gas declines than crude oil. We expect our natural gas gathered and processed volumes in the Williston Basin to continue to grow in 2016, despite expected reductions in producer drilling activity. The significant drilling activity in recent years in the Williston Basin has caused natural gas production to exceed the capacity of existing natural gas gathering and processing infrastructure, which results in the flaring of natural gas (the controlled burning of natural gas at the wellhead) by producers. We expect to capture a substantial amount of natural gas currently being flared by producers due to an additional processing plant and compression projects that were placed in service in late 2015 and projects that are expected to be completed in 2016. Additionally, we expect to benefit from production from new wells on acreage dedicated to us in the Williston Basin that have been drilled previously but have not yet been completed or connected to our system by expanding our natural gas gathering and processing and natural gas liquids gathering infrastructure in the Williston Basin.

Supply growth has resulted in available ethane supplies that are greater than the petrochemical industry's current demand. As a result, low or unprofitable price differentials between ethane and natural gas have resulted in ethane rejection at most of our and our customers' natural gas processing plants connected to our natural gas liquids gathering system in the Mid-Continent and Rocky Mountain regions during 2014 and 2015, which reduced natural gas liquids volumes gathered, fractionated, transported and sold across our assets. Through ethane rejection, natural gas processors leave much of the ethane component in the natural gas stream sold at the tailgate of natural gas processing plants. We expect ethane rejection to persist at current levels, which have exceeded 150 MBbl/d on our natural gas liquids system during 2015, until ethylene producers increase their capacity to consume additional ethane feedstock volumes through plant modifications, plant expansions and the completion of announced new world-scale ethylene production projects, which are anticipated to begin coming on line in 2017. Ethane rejection is expected to continue to have a significant impact on our financial results into 2017.

Beginning in June 2015, our Natural Gas Gathering and Processing segment reduced its level of ethane rejection in the Williston Basin to alleviate downstream NGL product specification issues, which offsets partially the financial impact of ethane rejection. We expect this decreased ethane rejection to continue throughout 2016. In addition, our Natural Gas Liquids segment's integrated assets enable us to mitigate partially the impact of ethane rejection through minimum volume commitments, contract modifications that vary fees for ethane and other NGL products, and our ability to utilize the transportation capacity made available due to ethane rejection to capture additional NGL location price differentials, when they exist, in our optimization activities. See additional discussion in the "Financial Results and Operating Information" section of Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation.

Growth Projects - In 2015, crude oil and natural gas producers continued to drill for crude oil and NGL-rich natural gas in many regions where we have operations, including in the Bakken Shale and Three Forks formations in the Williston Basin; in the Cana-Woodford Shale, Woodford Shale, Springer Shale, Stack and SCOOP areas in the Mid-Continent region; and in the Permian Basin. In response to this continued production of crude oil, natural gas and NGLs, and higher demand for NGL products from the petrochemical industry, we have completed growth projects and acquisitions in these regions. In addition, our current projects are expected to expand our natural gas gathering and processing and natural gas liquids gathering infrastructure in the Williston Basin to capture natural gas currently being flared by producers. Through our Roadrunner joint venture, we are constructing a pipeline to transport natural gas from the Permian Basin in West Texas to the Mexican border near El Paso, Texas. The Roadrunner pipeline will connect with our existing natural gas pipeline and storage infrastructure in Texas and, together with our ONEOK WesTex Transmission (WesTex) intrastate natural gas pipeline system expansion project, is expected to create a platform for future opportunities to deliver natural gas supply to Mexico. The execution of these capital investments aligns with our strategy to generate consistent growth and sustainable earnings. Our contractual commitments from crude oil and natural gas producers, natural gas processors and electric generators are expected to provide incremental cash flows and long-term fee-based earnings.

While reduced crude oil and natural gas producer drilling activity is slowing supply growth, we expect to complete our previously announced projects to meet crude oil and natural gas producers' demands for our gathering, processing, fractionation and transportation services. We have suspended capital expenditures for certain natural gas processing plants and related infrastructure to align with the needs of our customers. We could resume our suspended capital-growth projects when market conditions improve and our customers' needs change. In 2016, we expect lower capital spending, compared with spending levels from 2013 through 2015, due to the current commodity price environment and our alignment of capital-growth projects with the needs of our customers. If the current commodity price environment persists for a prolonged period, it may further impact the timing or demand for additional infrastructure projects or growth opportunities in the future.

Impairment Charges - In the fourth quarter 2015, we recorded $264.3 million of noncash impairment charges, primarily related to our long-lived assets and equity investments in the dry natural gas area of the Powder River Basin.

Cash Distributions - Our structure as a master limited partnership requires us to pay out all of our available cash, as defined in our Partnership Agreement, in distributions to our unitholders. During 2015, we paid cash distributions of $3.16 per unit, an increase of approximately 5 percent over the $3.01 per unit paid during 2014. In January 2016, our general partner declared a cash distribution of $0.79 per unit ($3.16 per unit on an annualized basis) for the fourth quarter 2015.

Liquidity - We rely primarily on operating cash flows, commercial paper, bank credit facilities, debt issuances and the issuance of common units for our liquidity and capital resources requirements. As of December 31, 2015, we had $5.1 million of cash on hand and available capacity under our Partnership Credit Agreement of approximately $1.8 billion. In addition, in January 2016, we entered into the $1.0 billion senior unsecured Term Loan Agreement with a syndicate of banks that matures in January 2019. Proceeds from the Term Loan Agreement effectively refinance our 2016 debt maturities.

The significant decline in commodity prices has increased the cost of debt and equity financing for us and others in our industry. While lower commodity prices and industry uncertainty may result in increased financing costs, we believe we have secured sufficient access to the financial resources and liquidity necessary to meet our requirements for working capital, debt service payments and capital expenditures through 2016 and well into 2017.

In the first quarter 2015, we increased the capacity of our Partnership Credit Agreement to an aggregate of $2.4 billion from $1.7 billion. The facility is available to provide liquidity for working capital, capital expenditures and other general partnership purposes. We also increased the size of our commercial paper program to $2.4 billion from $1.7 billion during the first quarter 2015. At December 31, 2015, we had $246.3 million of commercial paper outstanding, $14.0 million of letters of credit issued and $300 million of borrowings outstanding under our Partnership Credit Agreement.

See Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation, for more information on our growth projects, results of operations, liquidity and capital resources.

BUSINESS STRATEGY

Our primary business strategy is to increase distributable cash flow per unit through consistent and sustainable earnings growth while focusing on safe, reliable, environmentally responsible and legally compliant operations for our customers, employees, contractors and the public through the following:

- <u>Operate in a safe, reliable and environmentally responsible manner</u> - environmental, safety and health issues continue to be a primary focus for us, and our emphasis on personal and process safety has produced improvements in the key indicators we track. We also continue to look for ways to reduce our environmental impact by conserving resources and utilizing more efficient technologies;
- <u>Generate consistent growth and sustainable earnings</u> - we have a predominantly fee-based business in our Natural Gas Liquids and Natural Gas Pipelines segments and have significantly increased the fee component in our Natural Gas Gathering and Processing segment's contracts. We are investing in growth projects to meet the needs of crude oil and natural gas producers. Through our Roadrunner joint venture, we are also investing in natural gas pipeline infrastructure from West Texas to the Mexican border that is expected to provide markets in Mexico access to upstream supply basins. When completed, our capital projects are anticipated to provide additional fee-based earnings and cash flows;
- <u>Manage our balance sheet and maintain investment-grade credit ratings</u> - even under challenging market conditions, our balance sheet remains strong. We ended 2015 with approximately $1.8 billion of credit available under the Partnership Credit Agreement, and in January 2016, we entered into the $1.0 billion Term Loan Agreement that effectively refinances our 2016 debt maturities. We seek to maintain investment-grade credit ratings; and
- <u>Attract, select, develop and retain a diverse group of employees to support strategy execution</u> - we continue to execute on our recruiting strategy that targets professional and field personnel in our operating areas. We also continue to

focus on employee development efforts with our current employees and monitor our benefits and compensation package to remain competitive.

NARRATIVE DESCRIPTION OF BUSINESS

We report operations in the following business segments:

- Natural Gas Gathering and Processing;
- Natural Gas Liquids; and
- Natural Gas Pipelines.

Natural Gas Gathering and Processing

Overview - Our Natural Gas Gathering and Processing segment provides nondiscretionary services to contracted producers in North Dakota, Montana, Wyoming, Kansas and Oklahoma. We provide exploration and production companies with gathering and processing services that allow them to move their raw (unprocessed) natural gas to market. Raw natural gas is gathered, compressed and transported through pipelines to our processing facilities. In order for the raw natural gas to be accepted by the downstream market, it must have contaminants, such as water, nitrogen and carbon dioxide, removed as well as NGLs separated for further processing. Processed natural gas, usually referred to as residue natural gas, is then recompressed and delivered to natural gas pipelines and end users. The separated NGLs are in a mixed, unfractionated form and are sold and delivered through natural gas liquids pipelines to fractionation facilities for further separation.

Rocky Mountain region - The Williston Basin is located in portions of North Dakota and Montana, including the oil-producing, NGL-rich Bakken Shale and Three Forks Formation, and is our most active region with continued volume growth and additional gathering and processing infrastructure needs. Our growth projects are expected to increase our gathering and processing capacity and allow us to capture natural gas from new wells being drilled, wells that have been drilled but have not yet been completed, and natural gas currently being flared by producers. The significant Williston Basin drilling activity in recent years has caused natural gas production to exceed the capacity of existing natural gas gathering and processing infrastructure, which results in the flaring of natural gas by producers. See further discussion of growth projects in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, including expected completion dates.

The Powder River Basin is located in Wyoming. This region includes the NGL-rich Frontier, Turner Sussex and Niobrara Shale where our Sage Creek system provides gathering and processing services to customers in the southeast portion of Wyoming.

Mid-Continent region - Our Mid-Continent region is located in Western Oklahoma, which includes the NGL-rich Cana-Woodford Shale, Stack, SCOOP, Woodford Shale, Springer Shale and the Mississippian Lime Formation; and Southwest Kansas, which includes the Hugoton Basin, Central Kansas Uplift Basin and the Mississippian Lime Formation. The Mid-Continent region includes active drilling in the Cana-Woodford Shale, Woodford Shale, Springer Shale, Stack and SCOOP areas in Oklahoma as well as mature areas with volumetric declines.

Revenues - Revenues for this segment are derived primarily from the following types of contracts:

- POP with fee-based components - Under this type of contract, we charge fees for gathering, treating, compressing and processing the producer's natural gas and retain a percentage of the proceeds from the sale of residue natural gas, condensate and/or NGLs. This type of contract represented approximately 90 percent and 87 percent of contracted volumes in this segment for 2015 and 2014, respectively. There are a variety of factors that directly affect our POP with fee revenues, including:
  - the price of natural gas, crude oil and NGLs;
  - the percentage of NGL, condensate and residue natural gas sales proceeds retained by us that we receive as part of the compensation for the services we provide;
  - the composition of the natural gas and NGLs produced;
  - the fees we charge for our services;
  - the volume produced; and
  - the costs incurred to provide our services.

  Over time as our contracts are renewed or restructured, we have generally increased the fee components and reduced the percent of proceeds retained from the sale of the commodities. As a result, our mix of commodity and fee-based earnings continue to change as volumes naturally decline on older contracts where we retain a higher percent of proceeds and volumes increase on contracts with higher fee components. Additionally, under certain POP with fee

contracts our fee revenues may increase or decrease if production volumes, delivery pressures or commodity prices change relative to specified thresholds.
- Fee-only - Under this type of contract, we are paid a fee for the services we provide, based on volumes gathered, processed, treated and/or compressed. Our fee-only contracts represented approximately 10 percent and 13 percent of contracted volumes in this segment for 2015 and 2014, respectively.

Our gathering and processing agreements have terms ranging from month to month to life of lease. Generally, our gathering and processing agreements are long-term agreements, typically five to 10 years. We have restructured many of our contracts to significantly increase our fee-based earnings and will continue to seek opportunities to similarly restructure additional contracts in 2016. As a result of these restructured contracts, we expect our Natural Gas Gathering and Processing segment's fee-based earnings to increase significantly and to favorably impact our 2016 results. In the fourth quarter 2015, our Natural Gas Gathering and Processing segment's fee rates averaged $0.55 per MMBtu, compared with an average of $0.36 per MMBtu in 2014. Our NGLs, natural gas and crude oil commodity price sensitivity in this segment is expected to decrease in 2016 as a result of these restructured contracts. Additionally, we use commodity derivative instruments and physical-forward contracts to reduce our near-term sensitivity to fluctuations in the natural gas, crude oil and NGL prices received for our share of volumes under POP with fee contracts.

Unconsolidated Affiliates - Our Natural Gas Gathering and Processing segment includes the following unconsolidated affiliates:

- 49 percent ownership in Bighorn Gas Gathering, which operates a coal-bed methane gathering system in the Powder River Basin;
- 37 percent ownership in Fort Union Gas Gathering, which gathers coal-bed methane produced in the Powder River Basin and delivers it to the interstate pipeline system;
- 35 percent ownership interest in Lost Creek Gathering Company, which gathers natural gas produced from conventional dry natural gas wells in the Wind River Basin of central Wyoming and delivers it to the interstate pipeline system; and
- 10 percent ownership interest in Venice Energy Services Co., a natural gas processing facility near Venice, Louisiana.

See Note M of the Notes to Consolidated Financial Statements in this Annual Report for additional discussion of our unconsolidated affiliates.

Market Conditions and Seasonality - Supply - *Rocky Mountain region* - In the Williston Basin, natural gas volumes continued to grow in 2015 as new well connections to our system from drilling completions increased, driven primarily by producer development of Bakken Shale crude oil wells, which also produce associated natural gas containing significant quantities of NGLs. We expect a reduction in well connections in 2016, compared with 2015, due to continued low commodity prices and reduced drilling and completion activity. Volumes are expected to increase in the Williston Basin due to the following:

- the opportunity to capture additional natural gas currently being flared by producers with additional natural gas compression and processing capacity on our systems due to projects placed in service in late 2015 and projects that are expected to be completed in 2016;
- the connection of wells that have been drilled but not yet completed or connected to our systems;
- producers focusing their drilling in the most productive areas, in which we have significant gathering and processing assets, which typically produce at higher initial production rates compared with other areas, have the highest natural gas content and have slower natural gas declines than crude oil;
- the use by producers of more efficient drilling rigs; and
- continued improvements in production results by producers due to enhanced completion techniques.

The NGL-rich natural gas from the Niobrara area in the Powder River Basin has experienced a reduction in drilling activity due to the current price environment; however, our long-term volume expectations have not materially changed due to the quality of reserves in these proven formations.

Mid-Continent region - In the Mid-Continent region, we have significant natural gas gathering and processing assets in Oklahoma and Kansas. We expect our average natural gas gathered volumes to grow in 2016 due to continued drilling and completion activity in the Cana-Woodford Shale, Woodford Shale, Springer Shale, Stack and SCOOP areas in Oklahoma, offset partially by the natural volume declines from existing wells that supply our natural gas gathering and processing facilities. Producers in the region are targeting their projects by drilling in the most productive areas and minimizing their costs by taking advantage of efficient drilling and completion techniques.

If the commodity price environment remains low or declines further, volumes in each region may grow more slowly than in the past or decline.

See further discussion of supply in the "Executive Summary" section.

Demand - Demand for gathering and processing services is dependent on production by producers, which is driven by the strength of the economy; natural gas, crude oil and NGL prices; and the demand for each of these products from end users. Our customers are generally crude oil and natural gas producers who have proven reserves or are currently producing gas in areas within our existing infrastructure. Our gathering and processing services are nondiscretionary for these producer customers, as the raw natural gas stream they produce has no marketable value until it is gathered and processed into commodities. Additionally, demand is impacted by the weather.

Rocky Mountain region - Demand for our gathering and processing services in the Williston Basin has remained strong even as crude oil prices have declined. Requirements in North Dakota to reduce producer natural gas flaring have increased the need for our services to capture this natural gas.

Mid-Continent region - Demand for our service remained constant and is linked directly to proven production sources and drilling and completion activities, which are primarily in the Cana Woodford, Springer Shale, Stack and SCOOP areas in Oklahoma. If the commodity price environment remains low or declines further, demand for our services in this region may grow more slowly than in the past or decline.

Commodity Prices - See discussion of commodity prices in the "Executive Summary" section.

Seasonality - Cold temperatures usually increase demand for natural gas, the main heating fuel for homes and businesses. Warm temperatures usually increase demand for natural gas used in gas-fired electric generators for residential and commercial cooling, as well as agriculture related equipment like irrigation pumps and crop dryers. During periods of peak demand for a certain commodity, prices for that product typically increase. However, in the current environment of natural gas oversupply and high storage levels, we do not expect prices to be materially affected by seasonality.

Extreme weather conditions can impact the volumes of natural gas gathered and processed. Freeze-offs are a phenomenon where water produced from natural gas freezes at the wellhead or within the gathering system. This causes a temporary interruption in the flow of natural gas. All of our operations may be affected by other weather conditions that may cause a loss of electricity at our facilities or prevent access to certain locations that affect a producer's ability to complete wells or our ability to connect those wells to our systems.

Competition - We compete for natural gas supply with major integrated oil companies, independent exploration and production companies that have gathering and processing assets, pipeline companies and their affiliated marketing companies, and other midstream gatherers and processors. The factors that typically affect our ability to compete for natural gas supply are:

- quality of services provided;
- producer drilling activity;
- products retained and/or fees charged under our gathering and processing contracts;
- location of our gathering systems relative to those of our competitors;
- location of our gathering systems relative to drilling activity;
- operating pressures maintained on our gathering systems;
- efficiency and reliability of our operations;
- delivery capabilities for natural gas and NGLs that exist in each system and plant location; and
- cost of capital.

Competition for natural gas gathering and processing services continues to increase as new infrastructure projects are completed to address increased production from shale and other resource areas. In response to these changing industry conditions, we continue to evaluate opportunities to increase earnings and cash flows, and reduce risk by:

- improving natural gas processing efficiency;
- reducing operating costs;
- consolidating assets;
- decreasing commodity price exposure; and
- restructuring low-margin contracts.

Customers - Our Natural Gas Gathering and Processing segment provides nondiscretionary services to crude oil and natural gas producers that include the gathering and processing of natural gas produced from crude oil and natural gas wells. Our customers include both large integrated and independent exploration and production companies. We are not typically exposed to material credit risk with producer customers under POP with fee contracts as we receive proceeds from the sale of commodities and remit a portion of those proceeds back to the crude oil and natural gas producers. In 2015, 99 percent of the downstream commodity sales in our Natural Gas Gathering and Processing segment were made to investment-grade customers, as rated by S&P or Moody's, or our comparable internal ratings, or secured by letters of credit or other collateral.

Government Regulation - The FERC traditionally has maintained that a natural gas processing plant is not a facility for the transportation or sale of natural gas in interstate commerce and, therefore, is not subject to jurisdiction under the Natural Gas Act. Although the FERC has made no specific declaration as to the jurisdictional status of our natural gas processing operations or facilities, our natural gas processing plants are primarily involved in extracting NGLs and, therefore, are exempt from FERC jurisdiction. The Natural Gas Act also exempts natural gas gathering facilities from the jurisdiction of the FERC. We believe our natural gas gathering facilities and operations meet the criteria used by the FERC for nonjurisdictional natural gas gathering facility status. Interstate transmission facilities remain subject to FERC jurisdiction. The FERC has historically distinguished between these two types of facilities, either interstate or intrastate, on a fact-specific basis. We transport residue natural gas from our natural gas processing plants to interstate pipelines in accordance with Section 311(a) of the Natural Gas Policy Act. Oklahoma, Kansas, Wyoming, Montana and North Dakota also have statutes regulating, to varying degrees, the gathering of natural gas in those states. In each state, regulation is applied on a case-by-case basis if a complaint is filed against the gatherer with the appropriate state regulatory agency.

Rocky Mountain region - In July 2014, the North Dakota Industrial Commission (NDIC) approved a policy designed to limit natural gas flaring at existing and future crude oil wells in the Williston Basin. The policy establishes crude oil production limits that will take effect if a producer fails to meet requirements to capture natural gas at the wellhead. We continue to participate actively on the North Dakota Petroleum Council's Flaring Task Force, which provides recommendations to the NDIC on policies and targets. In 2015, the NDIC passed updated natural gas capture percentages and associated timelines. None of these changes are expected to have a material impact on available production. We are constructing additional natural gas gathering pipelines, processing plants and natural gas liquids pipeline capacity that are expected to help alleviate capacity constraints. As a result, we expect our natural gas gathered and processed volumes in the Williston Basin to continue to grow in 2016, despite expected reductions in producer drilling activity, as we capture natural gas currently being flared by producers and natural gas produced with new drilling focused in the most productive areas.

See further discussion in the "Regulatory, Environmental and Safety Matters" section.

Natural Gas Liquids

Overview - Our Natural Gas Liquids segment owns and operates facilities that gather, fractionate, treat and distribute NGLs and store NGL products, primarily in Oklahoma, Kansas, Texas, New Mexico and the Rocky Mountain region where we provide nondiscretionary services to producers of NGLs and deliver those products to the two primary market centers, one in the Mid-Continent in Conway, Kansas, and the other in the Gulf Coast in Mont Belvieu, Texas. We own or have an ownership interest in FERC-regulated natural gas liquids gathering and distribution pipelines in Oklahoma, Kansas, Texas, New Mexico, Montana, North Dakota, Wyoming and Colorado, and terminal and storage facilities in Missouri, Nebraska, Iowa and Illinois. We also own FERC-regulated natural gas liquids distribution and refined petroleum products pipelines in Kansas, Missouri, Nebraska, Iowa, Illinois and Indiana that connect our Mid-Continent assets with Midwest markets, including Chicago, Illinois. The majority of the pipeline-connected natural gas processing plants in Oklahoma, Kansas and the Texas Panhandle, which extract unfractionated NGLs from unprocessed natural gas, are connected to our gathering systems. We own and operate truck- and rail-loading and -unloading facilities connected to our natural gas liquids fractionation and pipeline assets. In November 2014, we began transporting unfractionated NGLs from natural gas processing plants in the Permian Basin after completion of the West Texas LPG acquisition.

Most natural gas produced at the wellhead contains a mixture of NGL components, such as ethane, propane, iso-butane, normal butane and natural gasoline. The NGLs that are separated from the natural gas stream at natural gas processing plants remain in a mixed, unfractionated form until they are gathered, primarily by pipeline, and delivered to fractionators where the NGLs are separated into NGL products. These NGL products are then stored or distributed to our customers, such as petrochemical manufacturers, heating fuel users, ethanol producers, refineries, exporters and propane distributors.

Revenues for our Natural Gas Liquids segment are derived primarily from nondiscretionary fee-based services that we provide to our customers and from the physical optimization of our assets. Our fee-based services have increased due primarily to new supply connections; expansion of existing connections; the completion of capital projects, including our Bakken NGL Pipeline and Sterling III Pipeline; the West Texas LPG acquisition; and expansion of our NGL fractionation capacity, including the completion of our MB-2 and MB-3 fractionators. Our sources of earnings are categorized as exchange services, transportation and storage services, optimization and marketing and isomerization, which are defined as follows:

- Our exchange-services activities utilize our assets to gather, fractionate and/or treat unfractionated NGLs, thereby converting them into marketable NGL products that are stored and shipped to a market center or customer-designated location. Many of these exchange volumes are under contracts with minimum volume commitments. Our exchange services activities are primarily fee-based.
- Our transportation and storage services transport unfractionated NGLs, NGL products and refined petroleum products, primarily under FERC-regulated tariffs. Tariffs specify the maximum rates we charge our customers and the general terms and conditions for NGL transportation service on our pipelines. Our storage activities consist primarily of fee-based NGL storage services at our Mid-Continent and Gulf Coast storage facilities.
- Our optimization and marketing activities utilize our assets, contract portfolio and market knowledge to capture location, product and seasonal price differentials. We primarily transport NGL products between Conway, Kansas, and Mont Belvieu, Texas, to capture the location price differentials between the two market centers. Our natural gas liquids storage facilities also are utilized to capture seasonal price differentials. A growing portion of our marketing activities serves truck and rail markets.
- Our isomerization activities capture the price differential when normal butane is converted into the more valuable iso-butane at our isomerization unit in Conway, Kansas.

Excess NGL supply continues to result in narrow NGL location price differentials between the Mid-Continent and Gulf Coast market centers. We expect these narrow price differentials to persist as NGL production continues to increase and new fractionators and pipelines from various NGL-rich shale areas throughout the country, including our growth projects, have alleviated historical constraints affecting NGL prices and location price differentials between the Conway, Kansas, and Mont Belvieu, Texas, market centers.

Unconsolidated Affiliates - Our Natural Gas Liquids segment includes the following unconsolidated affiliates:

- 50 percent ownership interest in Overland Pass Pipeline Company, which operates an interstate natural gas liquids pipeline system extending approximately 760 miles, originating in Wyoming and Colorado and terminating in Kansas;
- 50 percent ownership interest in Chisholm Pipeline Company, which operates an interstate natural gas liquids pipeline system extending approximately 185 miles from origin points in Oklahoma and terminating in Kansas; and
- 50 percent ownership interest in Heartland Pipeline Company, which operates a terminal and pipeline system that transports refined petroleum products in Kansas, Nebraska and Iowa.

See Note M of the Notes to Consolidated Financial Statements in this Annual Report for additional discussion of unconsolidated affiliates.

Market Conditions and Seasonality - <u>Supply</u> - The unfractionated NGLs that we gather and transport originate primarily from natural gas processing plants connected to our gathering systems in Oklahoma, Kansas, Texas, New Mexico and the Rocky Mountain region. Our fractionation operations receive NGLs from a variety of processors and pipelines, including our affiliates, located in these regions. Supply for our Natural Gas Liquids segment depends on crude oil and natural gas drilling and production activities by producers, the decline rate of existing production, natural gas processing plant economics and capabilities, and the NGL content of the natural gas that is produced and processed in the areas in which we operate.

See additional discussion of supply in the “Executive Summary” section.

<u>Demand</u> - Demand for NGLs and the ability of natural gas processors to successfully and economically sustain their operations affect the volume of unfractionated NGLs produced by natural gas processing plants, thereby affecting the demand for NGL gathering, fractionation and distribution services. Natural gas and propane are subject to weather-related seasonal demand. Other NGL products are affected by economic conditions and the demand associated with the various industries that utilize the commodity, such as butanes and natural gasoline used by the refining industry as blending stocks for motor fuel, denaturant for ethanol and diluents for crude oil. Ethane, propane, normal butane and natural gasoline are used by the petrochemical industry to produce chemical products, such as plastic, rubber and synthetic fibers. Several petrochemical companies are constructing new plants, plant expansions, additions or enhancements that improve the light-NGL feed capability of their facilities due primarily to the increased supply and attractive price of ethane, compared with crude oil-based alternatives, as a petrochemical feedstock in the United States. The demand is expected to increase significantly beginning in 2017 when many of the new

petrochemical plants and plant modifications are expected to be completed. We do not expect the recent decline in crude oil, natural gas and natural gas liquids prices to impact adversely the construction of new petrochemical plants or plant modifications in the Gulf Coast region. In addition, we expect increased international demand for ethane, propane and butane to provide opportunities to increase fee-based earnings in our exchange and storage services and marketing activities.

Commodity Prices - Our Natural Gas Liquids segment provides primarily fee-based services. However, we are exposed to market risk associated with changes in the price of NGLs; the location differential between the Mid-Continent, Chicago, Illinois, and Gulf Coast regions; and the relative price differential between natural gas, NGLs and individual NGL products, which affect our NGL purchases and sales, and our exchange, storage, transportation, optimization and marketing financial results. Since 2013, supply growth from the development of NGL-rich areas and increased capacity available on pipelines that connect the Mid-Continent and Gulf Coast market centers resulted in NGL price differentials remaining narrow between the Mid-Continent market center at Conway, Kansas, and the Gulf Coast market center at Mont Belvieu, Texas. NGL storage revenue may be affected by price volatility and forward pricing of NGL physical contracts versus the price of NGLs on the spot market.

See additional discussion of commodity prices in the “Executive Summary” section.

Seasonality - Our natural gas liquids fractionation and pipeline operations typically experience some seasonal variation. Some NGL products stored and transported through our assets are subject to weather-related seasonal demand, such as propane, which can be used to heat homes during the winter heating season and for agricultural purposes such as crop drying in the fall. Demand for butanes and natural gasoline, which are primarily used by the refining industry as blending stocks for motor fuel, denaturant for ethanol and diluents for crude oil, may also be subject to some variability during seasonal periods when certain government restrictions on motor fuel blending products change. The ability of natural gas processors to produce NGLs also is affected by weather. Extreme weather conditions can impact the volumes of natural gas gathered and processed and NGL volumes gathered, transported and fractionated. Freeze-offs are a phenomenon where water produced from natural gas freezes at the wellhead or within the gathering system. This causes a temporary interruption in the flow of natural gas and, consequently, NGLs. Conversely, in periods of hot weather, the natural gas processing plants become less efficient in NGL recovery, and thus NGL recovery during the summer typically decreases.

Competition - Our Natural Gas Liquids segment competes with other fractionators; intrastate and interstate pipeline companies; storage providers and gatherers and transporters for NGL supply in the Rocky Mountain, Permian, Mid-Continent and Gulf Coast regions. The factors that typically affect our ability to compete for NGL supply are:

- quality of services provided;
- producer drilling activity;
- the petrochemical industry’s level of capacity utilization and feedstock requirements;
- fees charged under our contracts;
- current and forward NGL prices;
- location of our gathering systems relative to our competitors;
- location of our gathering systems relative to drilling activity;
- proximity to NGL supply areas and markets;
- efficiency and reliability of our operations;
- receipt and delivery capabilities that exist in each pipeline system, plant, fractionator and storage location; and
- cost of capital.

We have responded to these factors by making capital investments to access new supplies; increasing gathering, fractionation and distribution capacity; increasing storage, withdrawal and injection capabilities; and reducing operating costs so that we may compete effectively. Our competitors are constructing or have completed new natural gas liquids pipeline and fractionation projects to address the growing NGL supply and petrochemical demand. As our growth projects and those of our competitors have alleviated constraints between the Mid-Continent and Gulf Coast NGL market centers, we expect the narrow location price differentials between the two locations to continue. In addition, new natural gas liquids pipeline projects constructed by third parties are expected to bring incremental NGL supply from the Rocky Mountain, Marcellus and Utica basins to the Gulf Coast market center that may affect NGL prices, as well as compete with or displace NGL supply volumes from the Mid-Continent and Rocky Mountain regions where our assets are located. We believe our natural gas liquids fractionation, pipelines and storage assets are located strategically, connecting diverse supply areas to market centers.

Customers - Our Natural Gas Liquids segment’s customers are primarily NGL and natural gas gathering and processing companies; major and independent crude oil and natural gas production companies; propane distributors; ethanol producers; and petrochemical, refining and NGL marketing companies. We earn fee revenue from NGL and natural gas gathering and processing customers and natural gas liquids pipeline transportation customers. We are not typically exposed to material credit risk on the majority of our exchange services fee revenues, as we purchase NGLs from our gathering and processing customers and deduct our fee from the amounts we remit. We also earn commodity sales revenue from the downstream sales of NGL products. In 2015, more than 80 percent of our commodity sales were made to investment-grade customers, as rated by S&P or Moody's, or our comparable internal ratings, or secured by letters of credit or other collateral. In addition, the majority of our Natural Gas Liquids segment's pipeline tariffs provide us the ability to require security from shippers.

Government Regulation - The operations and revenues of our natural gas liquids pipelines are regulated by various state and federal government agencies. Our interstate natural gas liquids pipelines are regulated by the FERC, which has authority over the terms and conditions of service; rates, including depreciation and amortization policies; and initiation of service. In Oklahoma, Kansas and Texas, certain aspects of our intrastate natural gas liquids pipelines that provide common carrier service are subject to the jurisdiction of the OCC, KCC and RRC, respectively.

PHMSA has asserted jurisdiction over certain portions of our fractionation facilities in Bushton, Kansas, that it believes are subject to its jurisdiction. We have objected to the scope of PHMSA's jurisdiction and are seeking resolution of this matter. We do not anticipate that the cost of compliance will have a material adverse effect on our consolidated results of operations, financial position or cash flows.

See further discussion in the "Regulatory, Environmental and Safety Matters" section.

Natural Gas Pipelines

Overview - Our Natural Gas Pipelines segment provides transportation and storage services to end users through its wholly owned assets and its 50 percent ownership in Northern Border Pipeline. Our 50-50 Roadrunner joint venture currently is under construction, with Phase I expected to be completed in the first quarter 2016.

Interstate Pipelines - Our interstate pipelines are regulated by the FERC and are located in North Dakota, Minnesota, Wisconsin, Illinois, Indiana, Kentucky, Tennessee, Oklahoma, Texas and New Mexico. Our interstate pipeline companies include:

- Midwestern Gas Transmission, which is a bidirectional system that interconnects with Tennessee Gas Transmission Company's pipeline near Portland, Tennessee, and with several interstate pipelines at the Chicago Hub near Joliet, Illinois;
- Viking Gas Transmission, which is a bidirectional system that interconnects with a TransCanada Corporation pipeline near Emerson, Manitoba, and ANR Pipeline Company near Marshfield, Wisconsin;
- Guardian Pipeline, which interconnects with several pipelines at the Chicago Hub near Joliet, Illinois, and with local natural gas distribution companies in Wisconsin; and
- OkTex Pipeline, which has interconnections with several pipelines in Oklahoma, Texas and New Mexico.

Intrastate Pipelines - Our intrastate natural gas pipeline assets in Oklahoma transport natural gas through the state and have access to the major natural gas producing formations, including the Cana-Woodford Shale, Woodford Shale, Springer Shale, Granite Wash, Stack, SCOOP and Mississippian Lime. Our intrastate natural gas pipeline assets in Oklahoma serve end-use markets, such as local distribution companies and power generation companies. In Texas, our intrastate natural gas pipelines are connected to the major natural gas producing formations in the Texas Panhandle, including the Granite Wash formation and Delaware and Cline producing formations in the Permian Basin. The pipelines are capable of transporting natural gas throughout the western portion of Texas, including the Waha Hub where other pipelines may be accessed for transportation to western markets, exports to Mexico, the Houston Ship Channel market to the east and the Mid-Continent market to the north. We also have access to the natural gas producing formations in south central Kansas. Through our Roadrunner joint venture, we are constructing a pipeline to transport natural gas from the Permian Basin in West Texas to the Mexican border near El Paso, Texas. The Roadrunner pipeline will connect with our existing natural gas pipeline and storage infrastructure in Texas and, together with our WesTex intrastate natural gas pipeline expansion project, is expected to create a platform for future opportunities to deliver natural gas supply to Mexico.

Transportation Rates - Our transportation contracts for our regulated natural gas activities are based upon rates stated in the respective tariffs. The tariffs provide both the general terms and conditions for the facilities and the maximum allowed rates customers can be charged by type of service, which may be discounted to meet competition if necessary. The rates are established at FERC or the appropriate state jurisdictional agencies. Our revenues are primarily fee based from the following types of services:

- Firm service - Customers reserve a fixed quantity of pipeline capacity for a specified period of time, which obligates the customer to pay regardless of usage. Under this type of contract, the customer pays a monthly fixed fee and incremental fees, known as commodity charges, which are based on the actual volumes of natural gas they transport or store. In addition, we may retain a percentage of fuel in-kind based on the volumes of natural gas transported. Under the firm service contract, the customer generally is guaranteed access to the capacity they reserve.
- Interruptible service - Under interruptible service transportation agreements, the customer may utilize available capacity after firm service requests are satisfied. The customer is not guaranteed use of our pipelines unless excess capacity is available. Customers typically are assessed fees, such as a commodity charge, and we may retain a specified volume of natural gas in-kind based on their actual usage.

Storage - We own natural gas storage facilities located in Texas and Oklahoma that are connected to our intrastate natural gas pipelines. We also have underground natural gas storage facilities in Kansas. In Texas and Kansas, natural gas storage operations may be regulated by the state in which the facility operates and by the FERC for certain types of services. In Oklahoma, natural gas storage operations are not subject to rate regulation by the state and have market-based rate authority from the FERC for certain types of services.

Storage Rates - Our revenues are primarily fee based from the following types of services:

- Firm Service - Customers reserve a specific quantity of storage capacity, including injection and withdrawal rights, and generally pay fixed fees based on the quantity of capacity reserved plus an injection and withdrawal fee. Firm storage contracts typically have terms longer than one year.
- Park-and-Loan Service - An interruptible service offered to customers providing the ability to park (inject) or loan (withdraw) natural gas into or out of our storage, typically for monthly terms. Customers reserve the right to park or loan natural gas based on a specified quantity, including injection and withdrawal rights when capacity is available.

Unconsolidated Affiliates - Our Natural Gas Pipelines segment includes the following unconsolidated affiliates:

- 50 percent interest in Northern Border Pipeline, which owns a FERC-regulated interstate pipeline that transports natural gas from the Montana-Saskatchewan border near Port of Morgan, Montana, to a terminus near North Hayden, Indiana.
- 50 percent interest in Roadrunner, which is currently under construction, with Phase I expected to be completed in the first quarter 2016. The Roadrunner pipeline will transport natural gas from the Permian Basin in West Texas to the Mexican border near El Paso, Texas.

See Note M of the Notes to Consolidated Financial Statements in this Annual Report for additional discussion of unconsolidated affiliates.

Market Conditions and Seasonality - <u>Supply</u> - The development of natural gas produced from shale resource areas has continued to increase available supply across North America and has caused location and seasonal price differentials to narrow in the regions where we operate.

Interstate - Guardian Pipeline, Midwestern Gas Transmission and Viking Gas Transmission access supply from the major producing regions of the Mid-Continent, Rocky Mountains, Canada, Gulf Coast and the Northeast. The current supply of natural gas for Northern Border Pipeline is primarily sourced from Canada; however, as the Williston Basin supply area continues to develop, more natural gas supply from this area is expected to be transported on Northern Border Pipeline to markets near Chicago. In addition, supply volumes from nontraditional natural gas production areas, such as the Marcellus and Utica shale area in the Northeast, may compete with and displace volumes from the Mid-Continent, Rocky Mountain and Canadian supply sources in our markets. Factors that may impact the supply of Canadian natural gas transported by our pipelines are primarily the availability of United States supply, Canadian natural gas available for export, Canadian storage capacity, government regulation and demand for Canadian natural gas in Canada and United States consumer markets.

Intrastate and Storage **-** Our intrastate pipelines and storage assets may be impacted by the pace of drilling activity by crude oil and natural gas producers and the decline rate of existing production in the major natural gas production areas in the Mid-

Continent region, which includes the Cana-Woodford Shale, Granite Wash and Mississippian Lime areas, Hugoton Basin and Central Kansas Uplift Basin.

Demand - Demand for our services is related directly to our access to supply and the demand for natural gas by the markets that our natural gas pipelines and storage facilities serve. Demand is also affected by weather, the economy, natural gas price volatility and regulatory changes.

- Weather - The effect of weather on our natural gas pipelines operations is discussed below under "Seasonality."
- Economy - The strength of the economy directly impacts manufacturing and industrial companies that consume natural gas.
- Price volatility - Commodity price volatility can influence producers' decisions related to the production of natural gas. Our pipeline customers, primarily natural gas and electric utilities, require natural gas to operate their businesses and generally are not impacted by location price differentials. However, narrower location price differentials may impact demand for our services from natural gas marketers as discussed below under "Commodity Prices."
- Regulatory - Demand for our services is also affected as coal-fired electric generators are retired and replaced with alternative power generation fuels such as natural gas. EPA regulations on emissions from coal-fired electric-generation plants, including the Maximum Achievable Control Technology Standards and the Mercury and Air Toxics Standards, have increased the demand for natural gas as a fuel for electric generation, as well as related transportation and storage services. The demand for natural gas and related transportation and storage services is expected to increase over the next several years as these regulations continue to be implemented.

Commodity Prices - As a result of excess supplies of natural gas and the addition of natural gas infrastructure, the natural gas location and seasonal price differentials have remained narrow across the regions where we operate. Although our revenues are primarily fee based, commodity prices can affect our results of operations.

- Transportation - We are exposed to market risk through interruptible contracts or when existing firm contracts expire and are subject to renegotiation with customers that have competitive alternatives.
- Storage - Natural gas storage revenue is impacted by the differential between forward pricing of natural gas physical contracts and the price of natural gas on the spot market.
- Fuel - Our fuel costs and the value of the retained fuel in-kind received for our services also are impacted by changes in the price of natural gas.

Seasonality - Demand for natural gas is seasonal. Weather conditions throughout North America may significantly impact regional natural gas supply and demand. High temperatures may increase demand for gas-fired electric generation needed to meet the electricity demand required to cool residential and commercial properties. Cold temperatures may lead to greater demand for our transportation services due to increased demand for natural gas to heat residential and commercial properties. Low precipitation levels may impact the demand for natural gas that is used to fuel irrigation activity in the Mid-Continent region.

To the extent that pipeline capacity is contracted under firm-service transportation agreements, revenue, which is generated primarily from fixed fee charges, is not significantly impacted by seasonal throughput variations. However, when transportation agreements expire, seasonal demand may affect the value of firm-service transportation capacity.

Natural gas storage is necessary to balance the relatively steady natural gas supply with the seasonal demand of residential, commercial and electric-generation users. The majority of our storage capacity is contracted under firm-service agreements; however, we retain a portion of our storage capacity for operational purposes, and the remaining capacity is used to provide park-and-loan services.

Competition - Our natural gas pipelines and storage facilities compete directly with other intrastate and interstate pipeline companies and other storage facilities. Competition among pipelines and natural gas storage facilities is based primarily on fees for services, quality and reliability of services provided, current and forward natural gas prices, proximity to natural gas supply areas and markets, and access to capital. Competition for natural gas transportation services continues to increase as new infrastructure projects are completed and the FERC and state regulatory bodies continue to encourage more competition in the natural gas markets. Regulatory bodies also are encouraging the use of natural gas for electric generation that has traditionally been fueled by coal. The cost of coal and the associated rail transportation continues to compete with natural gas for this market; however, the clean-burning aspects of natural gas and abundance of supply make it an economically competitive and environmentally advantaged alternative. We believe that our pipelines and storage assets compete effectively due to their strategic locations connecting supply areas to market centers and other pipelines.

Customers - Our natural gas pipeline assets primarily serve local natural gas distribution companies, electric-generation facilities, large industrial companies, municipalities, irrigation customers and marketing companies. Our utility customers generally require our services regardless of commodity prices. In 2015, more than 85 percent of our revenues in this segment were from investment-grade customers, as rated by S&P or Moody's, or our comparable internal ratings, or secured by letters of credit or other collateral. In addition, the majority of our Natural Gas Pipeline segment's pipeline tariffs provide us the ability to require security from shippers.

Government Regulation - *Interstate* - Our interstate natural gas pipelines are regulated under the Natural Gas Act and Natural Gas Policy Act, which give the FERC jurisdiction to regulate virtually all aspects of this business, such as transportation of natural gas, rates and charges for services, construction of new facilities, depreciation and amortization policies, acquisition and disposition of facilities, and the initiation and discontinuation of services.

In November 2012, the FERC initiated a review of Viking Gas Transmission's rates pursuant to Section 5 of the Natural Gas Act. The parties reached agreement on the terms of a settlement that provides for a 2 percent reduction in transportation rates. The settlement was approved by the FERC in December 2013, and the revised rates became effective January 1, 2014.

In August 2014, Viking Gas Transmission filed a prefiling "Stipulation and Agreement in Resolutions of All Issues Concerning Adjustment in Rates of Viking Gas Transmission Company" (settlement) with the FERC. The settlement was approved on October 1, 2014, and became final on October 31, 2014. Rates under the settlement became effective January 1, 2015.

Intrastate - Our intrastate natural gas pipelines in Oklahoma, Kansas and Texas are regulated by the OCC, KCC and RRC, respectively. While we have flexibility in establishing natural gas transportation rates with customers, there is a maximum rate that we can charge our customers in Oklahoma and Kansas. In Kansas and Texas, natural gas storage may be regulated by the state and by the FERC for certain types of services. In Oklahoma, natural gas storage is not subject to rate regulation by the state, and we have market-based rate authority from the FERC for certain types of services.

See further discussion in the "Regulatory, Environmental and Safety Matters" section.

SEGMENT FINANCIAL INFORMATION

Operating Income, Customers and Total Assets - See Note P of the Notes to Consolidated Financial Statements in this Annual Report for disclosure by segment of our operating income and total assets and for a discussion of revenues from external customers.

REGULATORY, ENVIRONMENTAL AND SAFETY MATTERS

Environmental Matters - We are subject to multiple historical preservation, wildlife preservation and environmental laws and/or regulations that affect many aspects of our present and future operations. Regulated activities include, but are not limited to, those involving air emissions, storm water and wastewater discharges, handling and disposal of solid and hazardous wastes, wetlands preservation, hazardous materials transportation, and pipeline and facility construction. These laws and regulations require us to obtain and/or comply with a wide variety of environmental clearances, registrations, licenses, permits and other approvals. Failure to comply with these laws, regulations, licenses and permits may expose us to fines, penalties and/or interruptions in our operations that could be material to our results of operations. For example, if a leak or spill of hazardous substances or petroleum products occurs from pipelines or facilities that we own, operate or otherwise use, we could be held jointly and severally liable for all resulting liabilities, including response, investigation and cleanup costs, which could affect materially our results of operations and cash flows. In addition, emissions controls and/or other regulatory or permitting mandates under the Clean Air Act and other similar federal and state laws could require unexpected capital expenditures at our facilities. We cannot assure that existing environmental statutes and regulations will not be revised or that new regulations will not be adopted or become applicable to us.

In June 2013, the Executive Office of the President of the United States (the President) issued the President's Climate Action Plan, which includes, among other things, plans for further regulatory actions to reduce carbon emissions from various sources. In March 2014, the President released the Climate Action Plan - Strategy to Reduce Methane Emissions (Methane Strategy) that lists a number of actions the federal agencies will undertake to continue to reduce above-ground methane emissions from several industries, including the oil and natural gas sectors. The proposed measures outlined in the Methane Strategy include, without limitation, the following: collaboration with the states to encourage emission reductions; standards to minimize natural gas venting and flaring on public lands; policy recommendations for reducing emissions from energy infrastructure to increase the performance of the nation's energy transmission, storage and distribution systems; and continued efforts by PHMSA to require pipeline operators to take steps to eliminate leaks and prevent accidental methane releases and evaluate the progress of states in replacing cast-iron pipelines. The impact of any such regulatory actions on our facilities and operations is unknown. We continue to monitor these developments and the impact they may have on our businesses. Revised or additional statutes or regulations that result in increased compliance costs or additional operating restrictions could have a significant impact on our business, financial position, results of operations and cash flows.

Pipeline Safety - We are subject to PHMSA regulations, including pipeline asset integrity-management regulations. The Pipeline Safety Improvement Act of 2002 requires pipeline companies operating high-pressure pipelines to perform integrity assessments on pipeline segments that pass through densely populated areas or near specifically designated high-consequence areas. In January 2012, The Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 was signed into law. The law increased maximum penalties for violating federal pipeline safety regulations and directs the DOT and Secretary of Transportation to conduct further review or studies on issues that may or may not be material to us. These issues include, but are not limited to, the following:

- an evaluation on whether hazardous natural gas liquids and natural gas pipeline integrity-management requirements should be expanded beyond current high-consequence areas;
- a review of all natural gas and hazardous natural gas liquids gathering pipeline exemptions;
- a verification of records for pipelines in Class 3 and 4 locations and high-consequence areas to confirm maximum allowable operating pressures; and
- a requirement to test previously untested pipelines operating above 30 percent yield strength in high-consequence areas.

In October 2015, PHMSA issued a notice of proposed rule-making to its hazardous liquid pipeline safety regulations. Among other things, the proposed regulations would expand the current leak-detection requirements, apply new, more conservative repair criteria and establish timelines for inspecting pipeline facilities potentially affected by an extreme weather event or natural disaster. The proposal would also increase the stringency of integrity management program requirements and set deadlines for the use of internal inspection tools on certain systems. Comments on the proposed rule-making were due by January 2016. The potential capital and operating expenditures related to the referenced legislation and regulations are unknown, but we do not anticipate a material impact to our planned capital, operations and maintenance costs resulting from compliance with the current or pending regulations.

Air and Water Emissions - The Clean Air Act, the Clean Water Act, analogous state laws and/or regulations promulgated thereunder impose restrictions and controls regarding the discharge of pollutants into the air and water in the United States. Under the Clean Air Act, a federally enforceable operating permit is required for sources of significant air emissions. We may be required to incur certain capital expenditures for air pollution-control equipment in connection with obtaining or maintaining permits and approvals for sources of air emissions. The Clean Water Act imposes substantial potential liability for the removal of pollutants discharged to waters of the United States and remediation of waters affected by such discharge.

Federal, state and regional initiatives to measure and regulate GHG emissions are underway. We monitor all relevant federal and state legislation to assess the potential impact on our operations. The EPA's Mandatory Greenhouse Gas Reporting Rule requires annual GHG emissions reporting from affected facilities and the carbon dioxide emission equivalents for the natural gas delivered by us and the emission equivalents for all NGLs produced by us as if all of these products were combusted, even if they are used otherwise.

Our 2014 total reported emissions were approximately 45.7 million metric tons of carbon dioxide equivalents. This total includes direct emissions from the combustion of fuel in our equipment, such as compressor engines and heaters, as well as carbon dioxide equivalents from natural gas and NGL products delivered to customers and produced as if all such fuel and NGL products were combusted. The additional cost to gather and report this emission data did not have, and we do not expect it to have, a material impact on our results of operations, financial position or cash flows. In addition, Congress has considered, and may consider in the future, legislation to reduce GHG emissions, including carbon dioxide and methane. Likewise, the EPA may institute additional regulatory rule-making associated with GHG emissions from the oil and natural gas industry. At this time, no rule or legislation has been enacted that assesses any costs, fees or expenses on any of these emissions.

In April 2014, the EPA and the United States Army Corps of Engineers proposed a joint rule-making to redefine the definition of "Waters of the United States" under the Clean Water Act. The final rule was published in June 2015 and became effective on August 28, 2015. Multiple legal actions on the final rule were filed. In October 2015, the Unites States Court of Appeals for the Sixth Circuit entered an order of stay, which is still in effect, and postponed the effect of the final rule nationwide until it decided further proceedings in the case. The final rule is not expected to result in material impacts on our projects, facilities and operations.

The EPA's "Triggering and Tailoring Rules" regulate GHG emissions at new or modified facilities that meet certain criteria. Affected facilities are required to review best available control technology (BACT) and conduct air-quality analysis, impact analysis and public reviews with respect to such emissions. At current emission threshold levels, this rule has had a minimal impact on our existing facilities. In addition, in June 2014, the Supreme Court of the United States (Supreme Court), in a case styled*, Utility Air Regulatory Group v. EPA*, 530 U.S. (2014), held that an industrial facility's potential to emit GHG emissions alone cannot subject a facility to the permitting requirements for major stationary source provisions of the Clean Air Act. The decision invalidated the EPA's current Triggering and Tailoring Rule for GHG Prevention of Significant Deterioration (PSD) and Title V requirements as applied to facilities considered major sources only for GHGs (referred to as Step 2 sources). However, the Supreme Court also ruled that to the extent a source pursues a capital project (new construction or expansion of existing facility), which otherwise subjects the source to major source PSD permitting for conventional criteria pollutants, the permitting authorities may impose BACT analysis and emission limits for GHGs from those sources.

In April 2015, the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit), on remand from the Supreme Court, issued its order following the Supreme Court's decision in *Utility Air Regulatory Group v. EPA.* The D.C. Circuit's order: (1) formally vacated EPA regulations implementing the Tailoring Rule to the extent that they require a stationary source to obtain a PSD or Title V permit based solely on the source's GHG emissions; and (2) ordered the EPA to consider whether any further revisions to its regulations are appropriate in light of the Supreme Court's decision. In April 2015, the EPA issued a direct final rule to allow for the rescission of Clean Air Act PSD permits issued by the EPA or delegated state and local permitting authorities under Step 2 of the GHG Tailoring Rule. The direct final rule was to become effective unless adverse comments were received by the EPA. In August 2015, the EPA published the direct final rule to confirm that no adverse comments were received and that the rule was now in effect. We do not expect the direct final rule to have a material impact on our existing operations or design decisions for new project applications.

In July 2011, the EPA issued a proposed rule that would change the air emissions New Source Performance Standards, also known as NSPS, and Maximum Achievable Control Technology requirements applicable to the oil and natural gas industry, including natural gas production, processing, transmission and underground storage sectors. In April 2012, the EPA released the final rule, which includes new NSPS and air toxic standards for a variety of sources within natural gas processing plants, oil and natural gas production facilities and natural gas transmission stations. The rule also regulates emissions from the hydraulic fracturing of wells for the first time. The NSPS final rule became effective in October 2012, but the dates for compliance vary and depend in part upon the type of affected facility and the date of construction, reconstruction or modification.

In September 2015, the EPA published several proposed rule-makings that affect the oil and gas industry. The rule-makings included, but were not limited to, proposed amendments to the NSPS rule. The proposed amendments to the NSPS rule included, in part, the proposed direct regulation of methane emissions for the first time as an individual air pollutant from oil and gas sources, as part of the President's Methane Strategy. The public comments period on the proposed rule-makings ended on December 4, 2015.

In October 2015, the EPA issued a final rule-making to amend downward the National Ambient Air Quality Standards (NAAQS) for ground level ozone. The final rule requires revised designations of the areas in the various states for classification as in attainment or nonattainment for the new ozone NAAQS. Any areas determined to not attain the ozone NAAQS will implicate more strict air permitting requirements for new or modified sources that emit pollutants that contribute to ground level ozone.

At this time we do not anticipate a material impact to our planned capital, operations and maintenance costs resulting from compliance with the current or pending regulations outlined above. However, the EPA may issue additional responses, amendments and/or policy guidance on the final rules, which could alter our present expectations. Generally, the EPA rule-makings will require expenditures for updated emissions controls, monitoring and record-keeping requirements at affected facilities. We do not expect these expenditures will have a material impact on our results of operations, financial position or cash flows.

CERCLA - The federal Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), also commonly known as Superfund, imposes strict, joint and several liability, without regard to fault or the legality of the original act, on certain classes of "persons" (defined under CERCLA) who caused and/or contributed to the release of a hazardous substance into the environment. These persons include, but are not limited to, the owner or operator of a facility where the release occurred and/or companies that disposed or arranged for the disposal of the hazardous substances found at the facility. Under CERCLA, these persons may be liable for the costs of cleaning up the hazardous substances released into the environment, damages to natural resources and the costs of certain health studies. We do not expect our responsibilities under CERCLA will have a material impact on our results of operations, financial position or cash flows.

Chemical Site Security - The United States Department of Homeland Security (Homeland Security) released the Chemical Facility Anti-Terrorism Standards in 2007, and the new final rule associated with these regulations was issued in December 2014. We provided information regarding our chemicals via Top-Screens submitted to Homeland Security, and our facilities subsequently were assigned one of four risk-based tiers ranging from high (Tier 1) to low (Tier 4) risk, or not tiered at all due to low risk. To date, four of our facilities have been given a Tier 4 rating. Facilities receiving a Tier 4 rating are required to complete Site Security Plans and possible physical security enhancements. We do not expect the Site Security Plans and possible security enhancement costs to have a material impact on our results of operations, financial position or cash flows.

Pipeline Security - The United States Department of Homeland Security's Transportation Security Administration and the DOT have completed a review and inspection of our "critical facilities" and identified no material security issues. Also, the Transportation Security Administration has released new pipeline security guidelines that include broader definitions for the determination of pipeline "critical facilities." We have reviewed our pipeline facilities according to the new guideline requirements, and there have been no material changes required to date.

Environmental Footprint - Our environmental and climate change strategy focuses on minimizing the impact of our operations on the environment. These strategies include: (i) developing and maintaining an accurate GHG emissions inventory according to current rules issued by the EPA; (ii) improving the efficiency of our various pipelines, natural gas processing facilities and natural gas liquids fractionation facilities; (iii) following developing technologies for emissions control and the capture of carbon dioxide to keep it from reaching the atmosphere; and (iv) utilizing practices to reduce the loss of methane from our facilities.

We participate in the EPA's Natural Gas STAR Program to reduce voluntarily methane emissions. We continue to focus on maintaining low rates of lost-and-unaccounted-for methane gas through expanded implementation of best practices to limit the release of natural gas during pipeline and facility maintenance and operations.

EMPLOYEES

We do not employ directly any of the persons responsible for managing, operating or providing us with services related to our day-to-day business affairs. We have a service agreement with ONEOK and ONEOK Partners GP (the Services Agreement) under which our operations and the operations of ONEOK and its affiliates can combine or share certain common services in order to operate more efficiently and cost effectively. Under the Services Agreement, ONEOK provides us an equivalent type and amount of services that it provides to its other affiliates, including those services required to be provided pursuant to our Partnership Agreement. ONEOK Partners GP may purchase services from ONEOK and its affiliates pursuant to the terms of the Services Agreement. As of January 31, 2016, we utilized some or all of the services of 2,364 people in addition to the other resources provided by ONEOK and its affiliates.

INFORMATION AVAILABLE ON OUR WEBSITE

We make available, free of charge, on our website (www.oneokpartners.com) copies of our Annual Reports, Quarterly Reports, Current Reports on Form 8-K, amendments to those reports filed or furnished to the SEC pursuant to Section 13(a) or 15(d) of the Exchange Act and reports of holdings of our securities filed by our officers and directors under Section 16 of the Exchange Act as soon as reasonably practicable after filing such material electronically or otherwise furnishing it to the SEC. Copies of our Code of Business Conduct and Ethics, Governance Guidelines, Partnership Agreement and the written charter of our Audit Committee also are available on our website, and we will provide copies of these documents upon request. Our website and any contents thereof are not incorporated by reference into this report.

We also make available on our website the Interactive Data Files required to be submitted and posted pursuant to Rule 405 of Regulation S-T.

ITEM 1A. RISK FACTORS

Our investors should consider the following risks that could affect us and our business. Although we have tried to identify key factors, our investors need to be aware that other risks may prove to be important in the future. New risks may emerge at any time, and we cannot predict such risks or estimate the extent to which they may affect our financial performance. Investors should consider carefully the following discussion of risks and the other information included or incorporated by reference in this Annual Report, including "Forward-Looking Statements," which are included in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations.

RISKS INHERENT IN OUR BUSINESS

We are subject to market volatility and other risks that could limit our access to capital, thereby increasing our costs and affecting adversely our results of operations.

The capital and global credit markets have experienced volatility and disruption in the past. In many cases during these periods, the capital markets have exerted downward pressure on equity values and reduced the credit capacity for certain companies. Much of our business is capital intensive, and our ability to grow is dependent, in part, upon our ability to access capital at rates and on terms we determine to be attractive. Similar or more severe levels of global market disruption and volatility may have an adverse effect on us resulting from, but not limited to, disruption of our access to capital and credit markets, difficulty in obtaining financing necessary to expand facilities or acquire assets, increased financing costs and increasingly restrictive covenants. If we are unable to access capital at competitive rates, our strategy of enhancing the earnings potential of our existing assets, including through capital-growth projects and acquisitions of complementary assets or businesses, may be affected adversely. A number of factors could affect adversely our ability to access capital, including: (i) general economic conditions; (ii) capital market conditions; (iii) market prices for natural gas, NGLs and other hydrocarbons; (iv) the overall health of the energy and related industries; (v) ability to maintain investment-grade credit ratings; (vi) unit price and (vii) capital structure. If our ability to access capital becomes constrained significantly, our interest costs and cost of equity will likely increase and could affect adversely our financial condition and future results of operations.

Increased competition could have a significant adverse financial impact on our business.

The natural gas and natural gas liquids industries are expected to remain highly competitive. The demand for natural gas and NGLs is primarily a function of commodity prices, including prices for alternative energy sources, customer usage rates, weather, economic conditions and service costs. Our ability to compete also depends on a number of other factors, including competition from other companies for our existing customers; the efficiency, quality and reliability of the services we provide; and competition for throughput at our gathering systems, pipelines, processing plants, fractionators and storage facilities.

Our operating results may be affected materially and adversely by unfavorable economic and market conditions.

Economic conditions worldwide have from time to time contributed to slowdowns in the crude oil and natural gas industry, as well as in the specific segments and markets in which we operate, resulting in reduced demand and increased price competition for our products and services. Our operating results in one or more geographic regions may also be affected by uncertain or changing economic conditions within that region. Volatility in commodity prices may have an impact on many of our customers, which, in turn, could have a negative impact on their ability to meet their obligations to us. If global economic and market conditions (including volatility in commodity markets) or economic conditions in the United States or other key markets remain uncertain or persist, spread or deteriorate further, we may experience material impacts on our business, financial condition, results of operations and liquidity.

The volatility of natural gas, crude oil and NGL prices could affect adversely our earnings and cash flows.

A significant portion of our revenues are derived from the sale of commodities that are received as payment for natural gas gathering and processing services, for the transportation and storage of natural gas, and from the purchase and sale of NGLs and NGL products. Commodity prices have been volatile and are likely to continue to be so in the future. The prices we receive for our commodities are subject to wide fluctuations in response to a variety of factors beyond our control, including, but not limited to, the following:

- overall domestic and global economic conditions;
- relatively minor changes in the supply of, and demand for, domestic and foreign energy;
- market uncertainty;
- the availability and cost of third-party transportation, natural gas processing and fractionation capacity;
- the level of consumer product demand and storage inventory levels;
- ethane rejection;
- geopolitical conditions impacting supply and demand for natural gas, NGLs and crude oil;
- weather conditions;
- domestic and foreign governmental regulations and taxes;
- the price and availability of alternative fuels;
- speculation in the commodity futures markets;
- the effects of imports and exports on the price of natural gas, crude oil, NGL and liquefied natural gas;

- the effect of worldwide energy-conservation measures; and
- the impact of new supplies, new pipelines, processing and fractionation facilities on location price differentials.

These external factors and the volatile nature of the energy markets make it difficult to reliably estimate future prices of commodities and the impact commodity price fluctuations have on our customers and their need for our services, which could have a material adverse effect on our earnings and cash flows. As commodity prices decline, we are paid less for our commodities, thereby reducing our cash flow. In addition, crude oil, natural gas and NGL production could also decline due to lower prices.

If the level of drilling and production in the Mid-Continent, Rocky Mountain, Permian Basin and Gulf Coast regions declines substantially near our assets, our volumes and revenues could decline.

Our gathering and transportation pipeline systems are connected to, and dependent on the level of production from, natural gas and crude oil wells, from which production will naturally decline over time. As a result, our cash flows associated with these wells will also decline over time. In order to maintain or increase throughput levels on our gathering and transportation pipeline systems and the asset utilization rates at our processing and fractionation plants, we must continually obtain new supplies. Our ability to maintain or expand our businesses depends largely on the level of drilling and production by third parties in the Mid-Continent, Rocky Mountain, Permian Basin and Gulf Coast regions. Our natural gas and NGL supply volumes may be impacted if producers curtail or redirect drilling and production activities. Drilling and production are impacted by factors beyond our control, including:

- demand and prices for natural gas, NGLs and crude oil;
- producers' access to capital;
- producers' finding and development costs of reserves;
- producers' desire and ability to obtain necessary permits in a timely and economic manner;
- natural gas field characteristics and production performance;
- surface access and infrastructure issues; and
- capacity constraints on natural gas, crude oil and natural gas liquids infrastructure from the producing areas and our facilities.

Commodity prices have declined substantially and experienced significant volatility. Drilling and production activity levels may vary across our geographic areas; however, a prolonged period of low commodity prices may reduce drilling and production activities across all areas. If we are not able to obtain new supplies to replace the natural decline in volumes from existing wells or because of competition, throughput on our gathering and transportation pipeline systems and the utilization rates of our processing and fractionation facilities would decline, which could have a material adverse effect on our business, results of operations, financial position and cash flows, and our ability to make cash distributions.

We are exposed to the credit risk of our customers or counterparties, and our credit risk management may not be adequate to protect against such risk.

We are subject to the risk of loss resulting from nonpayment and/or nonperformance by our customers and counterparties. Our customers or counterparties may experience rapid deterioration of their financial condition as a result of changing market conditions, commodity prices or financial difficulties that could impact their creditworthiness or ability to pay us for our services. We assess the creditworthiness of our customers and counterparties and obtain collateral or contractual terms as we deem appropriate. We cannot, however, predict to what extent our business may be impacted by deteriorating market or financial conditions, including possible declines in our customers' and counterparties' creditworthiness. The recent decline in commodity prices has negatively impacted the financial condition of certain customers and counterparties and further declines, a prolonged low commodity price environment, or continued volatility could impact their ability to meet their financial obligations to us. Our customers and counterparties may not perform or adhere to our existing or future contractual arrangements. To the extent our customers and counterparties are in financial distress or commence bankruptcy proceedings, contracts with them may be subject to renegotiation or rejection under applicable provisions of the United States Bankruptcy Code. If we fail to assess adequately the creditworthiness of existing or future customers and counterparties any material nonpayment or nonperformance by our customers and counterparties due to inability or unwillingness to perform or adhere to contractual arrangements could have a material adverse impact on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

Our primary market areas are located in the Mid-Continent, Rocky Mountain, Permian Basin and Gulf Coast regions of the U.S. Our revenues are derived primarily from major integrated and independent exploration and production, pipeline, marketing and petrochemical companies. Therefore our customers and counterparties may be similarly affected by changes in economic, regulatory or other factors that may affect our overall credit risk.

We may not be able to generate sufficient cash from operations to allow us to pay quarterly distributions at current or higher levels after the establishment of cash reserves and payment of fees and expenses, including payments to our affiliates.

The amount of cash we can distribute to our unitholders depends principally upon the cash we generate from our operations, which includes activities with our affiliates. Because the cash we generate from operations will fluctuate from quarter to quarter, we may not be able to maintain future quarterly distributions at the current level. The actual amount of cash that is available to be distributed each quarter will depend on numerous factors, some of which are beyond our control and the control of our general partner. Cash distributions are dependent primarily on cash flow, including cash flow from operations, cash from financial reserves and working capital borrowings, and not solely on profitability, which is affected by noncash items. Therefore, cash distributions might be made during periods when we record losses and might not be made during periods when we record profits. We may not have sufficient available cash from operating surplus each quarter to enable us to make cash distributions at our current distribution rate under our cash distribution policy. The amount of cash we can distribute principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the fees we charge and the income we realize for our services;
- the prices of, levels of production of and demand for, natural gas, NGLs and crude oil;
- the volume of natural gas we gather, treat, compress, process, transport and sell and the volume of NGLs we process or fractionate and sell;
- the relationship between natural gas and NGL prices;
- cash settlements of hedging positions;
- the level of competition from other midstream energy companies;
- the level of our operating and maintenance costs; and
- prevailing economic conditions.

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

- the level of capital expenditures we make;
- the cost of acquisitions;
- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- restrictions on distributions contained in our debt agreements; and
- the amount of cash reserves established by our general partner for the proper conduct of our business.

Cost reimbursements payable to our general partner may be substantial and may reduce our ability to pay quarterly distributions.

Prior to paying quarterly distributions, we will reimburse our general partner for all expenses it has incurred on our behalf. In addition, our general partner and its affiliates may provide us with services for which we will be charged reasonable fees as determined by our general partner in accordance with the terms of the Services Agreement. The reimbursement of these expenses and the payment of these fees could adversely affect our ability to pay quarterly distributions. Our general partner has sole discretion to determine the amount of these expenses and fees, subject to certain limitations as set forth in the Services Agreement.

Our businesses are subject to market and credit risks.

We are exposed to market and credit risks in all of our operations. To reduce the impact of commodity price fluctuations, we may use derivative instruments, such as swaps, futures and forwards, to hedge anticipated purchases and sales of natural gas, NGLs, crude oil and firm transportation commitments. Interest-rate swaps are also used to manage interest-rate risk. However, derivative instruments do not eliminate the risks. Specifically, such risks include commodity price changes, market supply shortages, interest-rate changes and counterparty default. The impact of these variables could result in our inability to fulfill contractual obligations, significantly higher energy or fuel costs relative to corresponding sales contracts, or increased interest expense.

We do not hedge fully against commodity price changes, seasonal price differentials, product price differentials or location price differentials. This could result in decreased revenues, increased costs and lower margins, adversely affecting our results of operations.

Our businesses are exposed to market risk and the impact of market fluctuations in natural gas, NGLs and crude oil prices. Market risk refers to the risk of loss of cash flows and future earnings arising from adverse changes in commodity prices. Our primary commodity price exposures arise from:

- the value of the NGLs and natural gas we receive as a portion of our compensation for the natural gas gathering and processing services we provide;
- the price differentials between the individual NGL products with respect to our NGL transportation and fractionation agreements;
- the location price differentials in the price of natural gas and NGLs with respect to our natural gas and NGL transportation businesses;
- the seasonal price differentials in natural gas and NGLs related to our storage operations; and
- the fuel costs and the value of the retained fuel in-kind in our natural gas pipelines and storage operations.

To manage the risk from market price fluctuations in natural gas, NGLs and crude oil prices, we may use derivative instruments such as swaps, futures, forwards and options. However, we do not hedge fully against commodity price changes and, we therefore retain some exposure to market risk. Accordingly, any adverse changes to commodity prices could result in decreased revenue and increased costs.

Our use of financial instruments and physical forward transactions to hedge market-risk exposure to commodity price and interest-rate fluctuations may result in reduced income.

We utilize financial instruments and physical forward transactions to mitigate our exposure to interest rate and commodity price fluctuations. Hedging instruments that are used to reduce our exposure to interest-rate fluctuations could expose us to risk of financial loss where we have contracted for variable-rate swap instruments to hedge fixed-rate instruments and the variable rate exceeds the fixed rate. In addition, these hedging arrangements may limit the benefit we would otherwise receive if we had contracted for fixed-rate swap agreements to hedge variable-rate instruments and the variable rate falls below the fixed rate. Hedging arrangements that are used to reduce our exposure to commodity price fluctuations limit the benefit we would otherwise receive if market prices for natural gas, crude oil and NGLs exceed the stated price in the hedge instrument for these commodities.

Demand for natural gas and for certain of our products and services is highly weather sensitive and seasonal.

The demand for natural gas and for certain of our products, such as propane, is weather sensitive and seasonal, with a portion of revenues derived from sales for heating during the winter months. Weather conditions influence directly the volume of, among other things, natural gas and propane delivered to customers. Deviations in weather from normal levels and the seasonal nature of certain of our segments can create variations in earnings and short-term cash requirements.

Energy efficiency and technological advances may affect the demand for natural gas and affect adversely our operating results.

More strict local, state and federal energy-conservation measures in the future or technological advances in heating, including installation of improved insulation and the development of more efficient furnaces, energy generation or other devices could affect the demand for natural gas and adversely affect our results of operations and cash flows.

Changes in interest rates could affect adversely our business.

We use both fixed and variable rate debt, and we are exposed to market risk due to the floating interest rates on our short-term borrowings. From time to time we use interest-rate derivatives to hedge interest obligations on specific debt issuances, including anticipated debt issuances. These hedges may be ineffective, and our results of operations, cash flows and financial position could be adversely affected by significant fluctuations in interest rates from current levels.

Our established risk-management policies and procedures may not be effective, and employees may violate our risk-management policies.

We have developed and implemented a comprehensive set of policies and procedures that involve both our senior management and the Audit Committee of ONEOK Partners GP's Board of Directors to assist us in managing risks associated with, among other things, the marketing, trading and risk-management activities associated with our business segments. Our risk policies and procedures are intended to align strategies, processes, people, information technology and business knowledge so that risk is managed throughout the organization. As conditions change and become more complex, current risk measures may fail to assess adequately the relevant risk due to changes in the market and the presence of risks previously unknown to us. Additionally, if employees fail to adhere to our policies and procedures or if our policies and procedures are not effective, potentially because of future conditions or risks outside of our control, we may be exposed to greater risk than we had intended. Ineffective risk-management policies and procedures or violation of risk-management policies and procedures could have an adverse effect on our earnings, financial position or cash flows.

We may not be able to develop and execute growth projects and acquire new assets which could result in reduced cash distributions to our unitholders.

Our primary business objectives are to generate cash flow sufficient to pay quarterly cash distributions to our unitholders and to increase our quarterly cash distributions over time. Our ability to maintain and grow our distributions to unitholders depends on the growth of our existing businesses and strategic acquisitions. If we are unable to implement business development opportunities and finance such activities on economically acceptable terms, our future growth will be limited, which could adversely impact our results of operations and cash flows and, accordingly, result in reduced cash distributions over time.

Growing our business by constructing new pipelines and plants or making modifications to our existing facilities subjects us to construction risk and supply risks, should adequate natural gas or NGL supply be unavailable upon completion of the facilities.

One of the ways we may grow our businesses is through the construction of new pipelines and new gathering, processing, storage and fractionation facilities and through modifications to our existing pipelines and existing gathering, processing, storage and fractionation facilities. The construction and modification of pipelines and gathering, processing, storage and fractionation facilities may face the following risks:

- projects may require significant capital expenditures, which may exceed our estimates, and involves numerous regulatory, environmental, political, legal and weather-related uncertainties;
- projects may increase demand for labor, materials and rights of way, which may, in turn, affect our costs and schedule;
- we may be unable to obtain new rights of way to connect new natural gas or NGL supplies to our existing gathering or transportation pipelines;
- if we undertake these projects, we may not be able to complete them on schedule or at the budgeted cost;
- our revenues may not increase immediately upon the expenditure of funds on a particular project. For instance, if we build a new pipeline, the construction will occur over an extended period of time, and we will not receive any material increases in revenues until after completion of the project;
- we may have only limited natural gas or NGL supply committed to these facilities prior to their construction;
- we may construct facilities to capture anticipated future growth in production in a region in which anticipated production growth does not materialize;
- we may rely on estimates of proved reserves in our decision to construct new pipelines and facilities, which may prove to be inaccurate because there are numerous uncertainties inherent in estimating quantities of proved reserves; and
- we may be required to rely on third parties downstream of our facilities to have available capacity for our delivered natural gas or NGLs, which may not yet be operational.

As a result, new facilities may not be able to attract enough natural gas or NGLs to achieve our expected investment return, which could affect materially and adversely our results of operations, financial condition and cash flows.

We may not be able to make additional strategic acquisitions or investments.

Our ability to make strategic acquisitions and investments will depend on:

- the extent to which acquisitions and investment opportunities become available;
- our success in bidding for the opportunities that do become available;
- regulatory approval, if required, of the acquisitions or investments on favorable terms; and

- our access to capital, including our ability to use our equity in acquisitions or investments, and the terms upon which we obtain capital.

If we are unable to make strategic investments and acquisitions, we may be unable to grow.

Acquisitions that appear to be accretive may nevertheless reduce our cash from operations on a per-unit basis.

Any acquisition involves potential risks that may include, among other things:

- inaccurate assumptions about volumes, revenues and costs, including potential synergies;
- an inability to integrate successfully the businesses we acquire;
- decrease in our liquidity as a result of our using a significant portion of our available cash or borrowing capacity to finance the acquisition;
- a significant increase in our interest expense and/or financial leverage if we incur additional debt to finance the acquisition;
- the assumption of unknown liabilities for which we are not indemnified, for which our indemnity is inadequate or for which our insurance policies may exclude from coverage;
- an inability to hire, train or retain qualified personnel to manage and operate the acquired business and assets;
- limitations on rights to indemnity from the seller;
- inaccurate assumptions about the overall costs of equity or debt;
- the diversion of management's and employees' attention from other business concerns;
- unforeseen difficulties operating in new product areas or new geographic areas;
- increased regulatory burdens;
- customer or key employee losses at an acquired business; and
- increased regulatory requirements.

If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and investors will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of our resources to future acquisitions.

We do not own all of the land on which our pipelines and facilities are located, and we lease certain facilities and equipment, which could disrupt our operations.

We do not own all of the land on which certain of our pipelines and facilities are located, and we are, therefore, subject to the risk of increased costs to maintain necessary land use. We obtain the rights to construct and operate certain of our pipelines and related facilities on land owned by third parties and governmental agencies for a specific period of time. Our loss of these rights, through our inability to renew right-of-way contracts on acceptable terms or increased costs to renew such rights, could have a material adverse effect on our financial condition, results of operations and cash flows.

Our operations are subject to operational hazards and unforeseen interruptions, which could affect materially and adversely our business and for which we may not be adequately insured.

Our operations are subject to all of the risks and hazards typically associated with the operation of natural gas and natural gas liquids gathering, transportation and distribution pipelines, storage facilities and processing and fractionation plants. Operating risks include, but are not limited to, leaks, pipeline ruptures, the breakdown or failure of equipment or processes and the performance of pipeline facilities below expected levels of capacity and efficiency. Other operational hazards and unforeseen interruptions include adverse weather conditions, accidents, explosions, fires, the collision of equipment with our pipeline facilities (for example, this may occur if a third party were to perform excavation or construction work near our facilities) and catastrophic events such as tornados, hurricanes, earthquakes, floods or other similar events beyond our control. It is also possible that our facilities could be direct targets or indirect casualties of an act of terrorism. A casualty occurrence might result in injury or loss of life, extensive property damage or environmental damage. Liabilities incurred and interruptions to the operations of our pipeline or other facilities caused by such an event could reduce revenues generated by us and increase expenses, thereby impairing our ability to meet our obligations. Insurance proceeds may not be adequate to cover all liabilities or expenses incurred or revenues lost, and we are not fully insured against all risks inherent to our business.

As a result of market conditions, premiums and deductibles for certain insurance policies can increase substantially, and, in some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. Consequently, we may not be able to renew existing insurance policies or purchase other desirable insurance on commercially reasonable terms, if at all. If we were to incur a significant liability for which we were not fully insured, it could have a material adverse effect on our financial position and results of operations. Further, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur.

Terrorist attacks directed at our facilities could adversely affect our business.

The United States government has issued warnings that energy assets, specifically the nation's pipeline infrastructure, may be future targets of terrorist organizations. These developments may subject our operations to increased risks. Any future terrorist attack that may target our facilities, those of our customers and, in some cases, those of other pipelines, could have a material adverse effect on our business.

Pipeline safety laws and regulations may impose significant costs and liabilities.

New pipeline safety legislation that was signed into law in 2012, The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 ("2011 Pipeline Safety Act"), directed the Secretary of Transportation to promulgate new safety regulations for natural gas and hazardous liquids pipelines, including expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation, testing to confirm the material strength of certain pipelines and operator verification of records confirming the maximum allowable pressure of certain gas transmission pipelines. The 2011 Pipeline Safety Act also increased the maximum penalty for violation of pipeline safety regulations from $100,000 to $200,000 per violation per day and also from $1 million to $2 million for a related series of violations. These regulations could cause us to incur capital and operating expenditures for pipeline replacements or repairs, additional monitoring equipment or more frequent inspections or testing of our pipeline facilities, preventive or mitigating measures and other tasks that could result in higher operating costs or capital expenditures.

Compliance with environmental regulations that we are subject to may be difficult and costly.

We are subject to multiple environmental laws and regulations affecting many aspects of present and future operations, including air emissions, water quality, wastewater discharges, solid and hazardous wastes, and hazardous material and substance management. These laws and regulations require us to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals. Failure to comply with these laws, regulations, permits and licenses may expose us to fines, penalties and/or interruptions in our operations that could be material to our results of operations. If a leak or spill of hazardous substance occurs from our pipelines, gathering lines or facilities in the process of transporting natural gas or NGLs or at any facility that we own, operate or otherwise use, we could be held jointly and severally liable for all resulting liabilities, including investigation and clean-up costs, which could affect materially our results of operations and cash flows. In addition, emission controls required under the federal Clean Air Act and similar federal and state laws could require unexpected capital expenditures at our facilities. We cannot assure that existing environmental regulations will not be revised or that new regulations will not be adopted or become applicable to us. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from customers, could have a material adverse effect on our business, financial condition and results of operations.

Our operations are subject to federal and state laws and regulations relating to the protection of the environment, which may expose us to significant costs and liabilities.

The risk of incurring substantial environmental costs and liabilities is inherent in our business. Our operations are subject to extensive federal, state and local laws and regulations governing the discharge of materials into, or otherwise relating to the protection of, the environment. Examples of these laws include:

- the Clean Air Act and analogous state laws that impose obligations related to air emissions;
- the Clean Water Act and analogous state laws that regulate discharge of wastewater from our facilities to state and federal waters;
- the federal CERCLA and analogous state laws that regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or locations to which we have sent waste for disposal; and
- the federal Resource Conservation and Recovery Act and analogous state laws that impose requirements for the handling and discharge of solid and hazardous waste from our facilities.

Various federal and state governmental authorities, including the EPA, have the power to enforce compliance with these laws and regulations and the permits issued under them. Violators are subject to administrative, civil and criminal penalties, including civil fines, injunctions or both. Joint and several, strict liability may be incurred without regard to fault under the CERCLA, Resource Conservation and Recovery Act and analogous state laws for the remediation of contaminated areas.

There is an inherent risk of incurring environmental costs and liabilities in our business due to our handling of the products we gather, transport, process and store, air emissions related to our operations, past industry operations and waste disposal practices, some of which may be material. Private parties, including the owners of properties through which our pipeline systems pass, may have the right to pursue legal actions to enforce compliance as well as to seek damages for noncompliance with environmental laws and regulations or for personal injury or property damage arising from our operations. Some sites we operate are located near current or former third-party hydrocarbon storage and processing operations, and there is a risk that contamination has migrated from those sites to ours. In addition, increasingly strict laws, regulations and enforcement policies could increase significantly our compliance costs and the cost of any remediation that may become necessary, some of which may be material. Additional information is included under Item 1, Business, under "Regulatory, Environmental and Safety Matters" and in Note O of the Notes to Consolidated Financial Statements in this Annual Report.

Our insurance may not cover all environmental risks and costs or may not provide sufficient coverage in the event an environmental claim is made against us. Our business may be affected materially and adversely by increased costs due to stricter pollution-control requirements or liabilities resulting from noncompliance with required operating or other regulatory permits. New environmental regulations might also materially and adversely affect our products and activities, and federal and state agencies could impose additional safety requirements, all of which could affect materially our profitability.

We may face significant costs to comply with the regulation of GHG emissions.

GHG emissions originate primarily from combustion engine exhaust, heater exhaust and fugitive methane gas emissions. Various federal and state legislative proposals have been introduced to regulate the emission of GHGs, particularly carbon dioxide and methane, and the United States Supreme Court has ruled that carbon dioxide is a pollutant subject to regulation by the EPA. In addition, there have been international efforts seeking legally binding reductions in emissions of GHGs.

We believe it is likely that future governmental legislation and/or regulation may require us either to limit GHG emissions from our operations or to purchase allowances for such emissions that are actually attributable to our NGL customers. However, we cannot predict precisely what form these future regulations will take, the stringency of the regulations or when they will become effective. Several legislative bills have been introduced in the United States Congress that would require carbon dioxide emission reductions. Previously considered proposals have included, among other things, limitations on the amount of GHGs that can be emitted (so called "caps") together with systems of permitted emissions allowances. These proposals could require us to reduce emissions, even though the technology is not currently available for efficient reduction, or to purchase allowances for such emissions. Emissions also could be taxed independently of limits.

In addition to activities on the federal level, state and regional initiatives could also lead to the regulation of GHG emissions sooner and/or independent of federal regulation. These regulations could be more stringent than any federal legislation that is adopted.

Future legislation and/or regulation designed to reduce GHG emissions could make some of our activities uneconomic to maintain or operate. Further, we may not be able to pass on the higher costs to our customers or recover all costs related to complying with GHG regulatory requirements. Our future results of operations, cash flows or financial condition could be adversely affected if such costs are not recovered through regulated rates or otherwise passed on to our customers.

We continue to monitor legislative and regulatory developments in this area. Although the regulation of GHG emissions may have a material impact on our operations and rates, we believe it is premature to attempt to quantify the potential costs of the impacts.

We are subject to physical and financial risks associated with climate change.

There is a growing belief that emissions of GHGs may be linked to global climate change. Climate change creates physical and financial risk. Our customers' energy needs vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling represent their largest energy use. To the extent weather conditions may be affected by climate change, customers' energy use could increase or decrease depending on the duration and magnitude of any changes. Increased energy use due to weather changes may require us to invest in more pipelines and other infrastructure to serve increased demand. A decrease in energy use due to weather changes may affect our financial condition, through decreased revenues. Extreme weather conditions in general require more system backup, adding to costs, and can contribute to increased system stresses, including service interruptions. Weather conditions outside of our operating territory could also have an impact on our revenues. Severe weather impacts our operating territories primarily through hurricanes, thunderstorms, tornados and snow or ice storms. To the extent the frequency of extreme weather events increases, this could increase our cost of providing service. We may not be able to pass on the higher costs to our customers or recover all costs related to mitigating these physical risks. To the extent financial markets view climate change and emissions of GHGs as a financial risk, this could affect negatively our ability to access capital markets or cause us to receive less favorable terms and conditions in future financings. Our business could be affected by the potential for lawsuits against GHG emitters, based on links drawn between GHG emissions and climate change.

Continued development of new supply sources could impact demand.

The discovery of nonconventional natural gas production areas nearer to certain of the market areas that we serve may compete with natural gas originating in production areas connected to our systems. For example, the Marcellus Shale in Pennsylvania, West Virginia and Ohio, may cause natural gas in supply areas connected to our systems to be diverted to markets other than our traditional market areas and may affect capacity utilization adversely on our pipeline systems and our ability to renew or replace existing contracts at rates sufficient to maintain current revenues and cash flows. In addition, supply volumes from these nonconventional natural gas production areas may compete with and displace volumes from the Mid-Continent, Permian, Rocky Mountains and Canadian supply sources in certain of our markets. In our Natural Gas Gathering and Processing segment, the development of these new nonconventional reserves could move drilling rigs from our current service areas to other areas, which may reduce demand for our services. In our Natural Gas Pipelines segment, the displacement of natural gas originating in supply areas connected to our pipeline systems by these new supply sources that are closer to the end-use markets could result in lower transportation revenues, which could have a material adverse impact on our business, financial condition, results of operations and cash flows.

Increased regulation of exploration and production activities, including hydraulic fracturing, could result in reductions or delays in drilling and completing new crude oil and natural gas wells, which could adversely impact our revenues by decreasing the volumes of natural gas and NGLs transported on our or our joint ventures' natural gas and natural gas liquids pipelines.

The natural gas industry is relying increasingly on natural gas supplies from nonconventional sources, such as shale and tight sands. Natural gas extracted from these sources frequently requires hydraulic fracturing, which involves the pressurized injection of water, sand and chemicals into a geologic formation to stimulate natural gas production. Recently, there have been initiatives at the federal and state levels to regulate or otherwise restrict the use of hydraulic fracturing or the disposal of waste water used in the hydraulic fracturing process, and several states have adopted regulations that impose more stringent permitting, disclosure and well-completion requirements on hydraulic fracturing operations. Legislation or regulations placing restrictions on hydraulic fracturing activities, including waste-water disposal, could impose operational delays, increased operating costs and additional regulatory burdens on exploration and production operators, which could reduce their production of unprocessed natural gas and, in turn, adversely affect our revenues and results of operations by decreasing the volumes of unprocessed natural gas and NGLs gathered, treated, processed, fractionated and transported on our or our joint ventures' natural gas and natural gas liquids pipelines, several of which gather unprocessed natural gas from areas where the use of hydraulic fracturing is prevalent.

In the competition for customers, we may have significant levels of uncontracted or discounted capacity on our natural gas and natural gas liquids pipelines, processing, fractionation and storage assets.

Our natural gas and natural gas liquids pipelines, processing, fractionation and storage assets compete with other pipelines, processing, fractionation and storage facilities for natural gas and NGL supply delivered to the markets we serve. As a result of competition, we may have significant levels of uncontracted or discounted capacity on our pipelines, processing, fractionation and in our storage assets, which could have a material adverse impact on our results of operations.

If production from the Western Canada Sedimentary Basin remains flat or declines and demand for natural gas from the Western Canada Sedimentary Basin is greater in market areas other than the Midwestern United States, demand for our interstate transportation services could decrease significantly.

We depend on a portion of natural gas supply from the Western Canada Sedimentary Basin for some of our interstate pipelines, primarily Viking Gas Transmission and our investment in Northern Border Pipeline, that transport Canadian natural gas from the Western Canada Sedimentary Basin to the Midwestern United States market area. If demand for natural gas increases in Canada or other markets not served by our pipelines and/or production remains flat or declines, demand for transportation service on our interstate natural gas pipelines could decrease significantly, which could adversely impact our business, financial condition, results of operations and cash flows.

We may not be able to replace, extend or add additional customer contracts or contracted volumes on favorable terms, or at all, which could affect our financial condition, the amount of cash available to pay distributions and our ability to grow.

Although many of our customers and suppliers are subject to long-term contracts, if we are unable to replace or extend such contracts, add additional customers or otherwise increase the contracted volumes of natural gas and NGLs provided to us by current producers, in each case on favorable terms, if at all, our financial condition, growth plans and the amount of cash available to pay distributions could be adversely affected. Our ability to replace, extend or add additional customer or supplier contracts, or increase contracted volumes of natural gas and NGLs from current producers, on favorable terms, or at all, is subject to a number of factors, some of which are beyond our control, including:

- the level of existing and new competition in our businesses or from alternative fuel sources, such as electricity, coal, fuel oils or nuclear energy;
- natural gas and NGL prices, demand, availability; and
- margins in our markets.

Mergers between our customers and competitors could result in lower volumes being gathered, processed, fractionated, transported or stored on our assets, thereby reducing the amount of cash we generate.

Mergers between our existing customers and our competitors could provide strong economic incentives for the combined entities to utilize their existing gathering, processing, fractionation and/or transportation systems instead of ours in those markets where the systems compete. As a result, we could lose some or all of the volumes and associated revenues from these customers, and we could experience difficulty in replacing those lost volumes and revenues. Because most of our operating costs are fixed, a reduction in volumes could result not only in less revenue but also in a decline in cash flow, which would reduce our ability to pay cash distributions to our unitholders.

Our business is subject to regulatory oversight and potential penalties.

The natural gas industry historically has been subject to heavy state and federal regulation that extends to many aspects of our businesses and operations, including:

- rates, operating terms and conditions of service;
- the types of services we may offer our customers;
- construction of new facilities;
- the integrity, safety and security of facilities and operations;
- acquisition, extension or abandonment of services or facilities;
- reporting and information posting requirements;
- maintenance of accounts and records; and
- relationships with affiliate companies involved in all aspects of the natural gas and energy businesses.

Compliance with these requirements can be costly and burdensome. Future changes to laws, regulations and policies in these areas may impair our ability to compete for business or to recover costs and may increase the cost and burden of operations. We cannot guarantee that state or federal regulators will authorize any projects or acquisitions that we may propose in the future. Moreover, there can be no guarantee that, if granted, any such authorizations will be made in a timely manner or will be free from potentially burdensome conditions.

Failure to comply with all applicable state or federal statutes, rules and regulations and orders could bring substantial penalties and fines. For example, under the Energy Policy Act of 2005, the FERC has civil penalty authority under the Natural Gas Act to impose penalties for current violations of up to $1 million per day for each violation.

Finally, we cannot give any assurance regarding future state or federal regulations under which we will operate or the effect such regulations could have on our business, financial condition, results of operations and cash flows.

Our regulated pipelines' transportation rates are subject to review and possible adjustment by federal and state regulators.

Under the Natural Gas Act, which is applicable to interstate natural gas pipelines, and the Interstate Commerce Act, which is applicable to crude oil and natural gas liquids pipelines, our interstate transportation rates, which are regulated by the FERC, must be just and reasonable and not unduly discriminatory.

Shippers may protest our pipeline tariff filings, and the FERC and or state regulatory agency may investigate tariff rates. Further, the FERC may order refunds of amounts collected under newly filed rates that are determined by the FERC to be in excess of a just and reasonable level. In addition, shippers may challenge by complaint the lawfulness of tariff rates that have become final and effective. The FERC and/or state regulatory agencies also may investigate tariff rates absent shipper complaint. Any finding that approved rates exceed a just and reasonable level on the natural gas pipelines would take effect prospectively. In a complaint proceeding challenging natural gas liquids pipeline rates, if the FERC determines existing rates exceed a just and reasonable level, it could require the payment of reparations to complaining shippers for up to two years prior to the complaint. Any such action by the FERC or a comparable action by a state regulatory agency could affect adversely our pipeline businesses' ability to charge rates that would cover future increases in costs, or even to continue to collect rates that cover current costs, and provide for a reasonable return. We can provide no assurance that our pipeline systems will be able to recover all of their costs through existing or future rates.

We are subject to comprehensive energy regulation by governmental agencies, and the recovery of our costs are dependent on regulatory action.

Federal, state and local agencies have jurisdiction over many of our activities, including regulation by the FERC of our interstate pipeline assets. The profitability of our regulated operations is dependent on our ability to pass through costs related to providing energy and other commodities to our customers by filing periodic rate cases. The regulatory environment applicable to our regulated businesses could impair our ability to recover costs historically absorbed by our customers.

We are unable to predict the impact that the future regulatory activities of these agencies will have on our operating results. Changes in regulations or the imposition of additional regulations could have an adverse impact on our business, financial condition and results of operations.

Our regulated pipeline companies have recorded certain assets that may not be recoverable from our customers.

Accounting policies for FERC-regulated companies permit certain assets that result from the regulated rate-making process to be recorded on our balance sheet that could not be recorded under GAAP for nonregulated entities. We consider factors such as regulatory changes and the impact of competition to determine the probability of future recovery of these assets. If we determine future recovery is no longer probable, we would be required to write off the regulatory assets at that time.

Some of our nonregulated businesses have a higher level of risk than our regulated businesses.

Some of our nonregulated operations, which include our natural gas gathering and processing business and most of our natural gas liquids business, have a higher level of risk than our regulated operations, which includes a portion of our natural gas pipelines business and a portion of our natural gas liquids business. We expect to continue investing in natural gas and natural gas liquids projects and other related projects, some or all of which may involve nonregulated businesses or assets. These projects could involve risks associated with operational factors, such as competition and dependence on certain suppliers and customers; and financial, economic and political factors, such as rapid and significant changes in commodity prices, the cost and availability of capital and counterparty risk, including the inability of a counterparty, customer or supplier to fulfill a contractual obligation.

A shortage of skilled labor may make it difficult for us to maintain labor productivity and competitive costs, which could affect operations and cash flows available for distribution to our unitholders.

Our operations require skilled and experienced workers with proficiency in multiple tasks. In recent years, a shortage of workers trained in various skills associated with the midstream energy business has caused us to conduct certain operations without full staff, thus hiring outside resources, which may decrease our productivity and increase our costs. This shortage of trained workers is the result of experienced workers reaching retirement age and increased competition for workers in certain areas, combined with the difficulty of attracting new workers to the midstream energy industry. This shortage of skilled labor could continue over an extended period. If the shortage of experienced labor continues or worsens, it could have an adverse impact on our labor productivity and costs and our ability to expand production in the event there is an increase in the demand for our products and services, which could adversely affect our operations and cash flows available for distribution to our unitholders.

We are subject to strict regulations at many of our facilities regarding employee safety, and failure to comply with these regulations could affect adversely our financial results.

The workplaces associated with our facilities are subject to the requirements of OSHA and comparable state statutes that regulate the protection of the health and safety of workers. The failure to comply with OSHA requirements or general industry standards, including keeping adequate records or monitoring occupational exposure to regulated substances, could expose us to civil or criminal liability, enforcement actions, and regulatory fines and penalties and could have a material adverse effect on our business, financial position, results of operations and cash flows.

Measurement adjustments on our pipeline system can be impacted materially by changes in estimation, type of commodity and other factors.

Natural gas and natural gas liquids measurement adjustments occur as part of the normal operating conditions associated with our assets. The quantification and resolution of measurement adjustments are complicated by several factors including: (1) the significant quantities (*i.e.*, thousands) of measurement equipment that we use throughout our natural gas and natural gas liquids systems, primarily around our gathering and processing assets; (2) varying qualities of natural gas in the streams gathered and processed through our systems and the mixed nature of NGLs gathered and fractionated; and (3) variances in measurement that are inherent in metering technologies. Each of these factors may contribute to measurement adjustments that can occur on our systems, which could negatively affect our business, financial position, results of operations and cash flows.

Many of our pipeline and storage assets have been in service for several decades.

Many of our pipeline and storage assets are designed as long-lived assets. Over time the age of these assets could result in increased maintenance or remediation expenditures and an increased risk of product releases and associated costs and liabilities. Any significant increase in these expenditures, costs or liabilities could materially adversely affect our results of operations, financial position or cash flows, as well as our ability to pay cash distributions.

A breach of information security, including a cybersecurity attack, or failure in of one or more key information technology or operational systems, or those of third parties, may affect adversely our operations, financial results or reputation.

Our businesses are dependent upon our operational systems to process a large amount of data and complex transactions. The various uses of these IT systems, networks and services include, but are not limited to:

- controlling our plants and pipelines with industrial control systems including Supervisory Control and Data Acquisition (SCADA);
- collecting and storing customer, employee, investor and other stakeholder information and data;
- processing transactions;
- summarizing and reporting results of operations;
- hosting, processing and sharing confidential and proprietary research, business plans and financial information;
- complying with regulatory, legal or tax requirements;
- providing data security; and
- handling other processing necessary to manage our business.

If any of our systems are damaged, fail to function properly or otherwise become unavailable, we may incur substantial costs to repair or replace them and may experience loss or corruption of critical data and interruptions or delays in our ability to perform critical functions, which could adversely affect our business and results of operations. Our financial results could also be affected adversely if an employee causes our operational systems to fail, either as a result of inadvertent error or by deliberately tampering with or manipulating our operational systems. In addition, dependence upon automated systems may further increase the risk that operational system flaws, employee tampering or manipulation of those systems will result in losses that are difficult to detect.

Due to increased technology advances, we have become more reliant on technology to help increase efficiency in our businesses. We use computer programs to help run our financial and operations organizations, and this may subject our business to increased risks. In recent years, there has been a rise in the number of cyberattacks on companies’ network and information systems by both state-sponsored and criminal organizations, and as a result, the risks associated with such an event continue to increase. A significant failure, compromise, breach or interruption in our systems could result in a disruption of our operations, customer dissatisfaction, damage to our reputation and a loss of customers or revenues. If any such failure, interruption or similar event results in the improper disclosure of information maintained in our information systems and networks or those of our vendors, including personnel, customer and vendor information, we could also be subject to liability under relevant contractual obligations and laws and regulations protecting personal data and privacy. Efforts by us and our vendors to develop, implement and maintain security measures may not be successful in preventing these events from occurring, and any network and information systems-related events could require us to expend significant resources to remedy such event. Although we believe that we have robust information security procedures and other safeguards in place, as cyberthreats continue to evolve, we may be required to expend additional resources to continue to enhance our information security measures and/or to investigate and remediate information security vulnerabilities.

Cyberattacks against us or others in our industry could result in additional regulations. Current efforts by the federal government, such as the Improving Critical Infrastructure Cybersecurity executive order, and any potential future regulations could lead to increased regulatory compliance costs, insurance coverage cost or capital expenditures. We cannot predict the potential impact to our business or the energy industry resulting from additional regulations.

If we fail to maintain an effective system of internal controls, we may not be able to report accurately our financial results or prevent fraud. As a result, current and potential holders of our equity and debt securities could lose confidence in our financial reporting, which would harm our business and cost of capital.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a public company. We cannot be certain that our efforts to maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to continue to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002. Any failure to maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our common units.

We may be unable to cause our joint ventures to take or not to take certain actions unless some or all of our joint-venture participants agree.

We participate in several joint ventures. Due to the nature of some of these arrangements, each participant in these joint ventures has made substantial investments in the joint venture and, accordingly, has required that the relevant charter documents contain certain features designed to provide each participant with the opportunity to participate in the management of the joint venture and to protect its investment, as well as any other assets that may be substantially dependent on or otherwise affected by the activities of that joint venture. These participation and protective features customarily include a corporate governance structure that requires at least a majority-in-interest vote to authorize many basic activities and requires a greater voting interest (sometimes up to 100 percent) to authorize more significant activities. Examples of these more significant activities are large expenditures or contractual commitments, the construction or acquisition of assets, borrowing money or otherwise raising capital, transactions with affiliates of a joint-venture participant, litigation and transactions not in the ordinary course of business, among others. Thus, without the concurrence of joint-venture participants with enough voting interests, we may be unable to cause any of our joint ventures to take or not to take certain actions, even though those actions may be in the best interest of us or the particular joint venture.

Moreover, any joint-venture owner generally may sell, transfer or otherwise modify its ownership interest in a joint venture, whether in a transaction involving third parties or the other joint-venture owners. Any such transaction could result in us being required to partner with different or additional parties.

An impairment of goodwill, long-lived assets, including intangible assets, and equity-method investments could reduce our earnings.

Goodwill is recorded when the purchase price of a business exceeds the fair market value of the tangible and separately measurable intangible net assets. GAAP requires us to test goodwill and intangible assets with indefinite useful lives for impairment on an annual basis or when events or circumstances occur indicating that goodwill might be impaired. Long-lived assets, including intangible assets with finite useful lives, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. For the investments we account for under the equity method, the impairment test considers whether the fair value of the equity investment as a whole, not the underlying net assets, has declined and whether that decline is other than temporary. For example, if the current depressed energy commodity price environment persists for a prolonged period or further declines, it could result in lower volumes delivered to our systems and impairments of our assets or equity-method investments. If we determine that an impairment is indicated, we would be required to take an immediate noncash charge to earnings with a correlative effect on equity and balance sheet leverage as measured by debt to total capitalization.

We may engage in acquisitions, divestitures and other strategic transactions, the success of which may impact our results of operations.

We may engage in acquisitions, divestitures and other strategic transactions. If we are unable to integrate successfully businesses that we acquire with our existing business, our results of operations may be affected materially and adversely. Similarly, we may from time to time divest portions of our business, which may also affect materially and adversely our results of operations.

RISKS INHERENT IN AN INVESTMENT IN US

Our general partner's absolute discretion in determining our level of cash reserves may adversely affect our ability to make cash distributions to our unitholders.

Our Partnership Agreement requires our general partner to deduct from available cash the amount of any cash reserves that it determines in its reasonable discretion are necessary to fund our future operating expenditures for the proper conduct of our business, to comply with applicable laws or agreements to which we are a party and to provide funds for future distributions to partners. Any such cash reserves will reduce the amount of cash currently available for distribution to our unitholders.

ONEOK's sale of substantial amounts of common units could reduce the market price of our common units.

ONEOK and its affiliates own all of the Class B units, 41.3 million common units and the entire 2 percent general partner interest in us, which together constituted a 41.2 percent ownership interest in us as of December 31, 2015. The Class B units are eligible to convert into common units on a one-for-one basis at ONEOK's option. ONEOK may, from time to time, sell all or a portion of its common units. Sales of substantial amounts of its common units or other types of units, or the anticipation of such sales, could lower the market price of our common units and may make it more difficult for us to sell our equity securities in the future at a time and price that we deem appropriate.

ONEOK could withdraw the waiver of its right to receive on its Class B units 110 percent of the distributions paid with respect to our common units.

At a special meeting of the holders of our common units held on May 10, 2007, the proposed amendments to our Partnership Agreement were not approved by the required two-thirds affirmative vote of our outstanding units, excluding the common units and Class B limited partner units held by ONEOK and its affiliates. As a result, effective April 7, 2007, ONEOK, as the sole holder of our Class B limited partner units, became entitled to receive increased quarterly distributions on its Class B units equal to 110 percent of the distributions paid with respect to our common units.

On June 21, 2007, ONEOK waived its right to receive the increased quarterly distributions on the Class B units for the period of April 7, 2007, through December 31, 2007, and continuing thereafter until ONEOK gives us no less than 90 days advance notice that it has withdrawn its waiver. ONEOK could withdraw such waiver and begin receiving such increased distributions, effective with respect to any distribution on the Class B units declared or paid on or after 90 days following delivery of the notice.

If our unitholders vote to remove ONEOK or its affiliates as our general partner, quarterly distributions and distributions payable to ONEOK upon liquidation of the Class B units would increase.

Since the proposed amendments to our Partnership Agreement were not approved by the requisite number of our common unitholders, if our common unitholders vote at any time to remove ONEOK or its affiliates as our general partner, quarterly distributions payable on the Class B limited partner units would increase to 123.5 percent of the distributions payable with respect to the common units, and distributions payable upon liquidation of the Class B limited partner units would increase to 123.5 percent of the distributions payable with respect to the common units.

Our unitholders have limited voting rights and are not entitled to elect our general partner's directors, which could lower the trading price of our common units. In addition, even if unitholders are dissatisfied, they cannot easily remove our general partner.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders have no right to elect our general partner or its directors on an annual or other continuing basis. The Board of Directors of our general partner, including the independent directors, is chosen by the owners of the general partner and not by the unitholders.

Furthermore, if unitholders are dissatisfied with the performance of our general partner, it may be difficult to remove ONEOK Partners GP or its officers or directors. ONEOK Partners GP may not be removed except upon the affirmative vote of the holders of at least two thirds of our outstanding units voting together as a single class (excluding units held by ONEOK Partners GP and its affiliates). As a result of this provision, the trading price of our common units may be lower than other forms of equity ownership because of the absence or reduction of a takeover premium in the trading price.

We do not operate all of our assets nor do we employ directly any of the persons responsible for providing us with administrative, operating and management services. This reliance on others to operate our assets and to provide other services could adversely affect our business and operating results.

We rely on ONEOK and ONEOK Partners GP to provide us with administrative, operating and management services. We have a limited ability to control our operations and the associated costs of such operations. The success of these operations depends on a number of factors that are outside our control, including the competence and financial resources of the provider. ONEOK and ONEOK Partners GP may outsource some or all of these services to third parties, and a failure to perform by these third-party providers could lead to delays in or interruptions of these services. Should ONEOK and ONEOK Partners GP not perform their respective contractual obligations, we may have to contract elsewhere for these services, which may cost more than we are currently paying. In addition, we may not be able to obtain the same level or kind of service or retain or receive the services in a timely manner, which may impact our ability to perform under our contracts and negatively affect our business and operating results. Our reliance on ONEOK and ONEOK Partners GP and third-party providers with which they contract, together with our limited ability to control certain costs, could harm our business and results of operations.

Our Partnership Agreement limits our general partner's fiduciary duties to our unitholders and restricts the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our Partnership Agreement contains provisions that reduce the standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our Partnership Agreement:

- permits our general partner to make a number of decisions considering only the interests and factors beneficial to itself or its parent, ONEOK, that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include the exercise of its limited call right, its voting rights with respect to the units it owns, its registration rights and its determination (through its Board of Directors) whether to consent to any merger or consolidation of us;
- provides that our general partner will not have any liability to us or our unitholders for decisions made in its capacity as general partner so long as it acted in “good faith,” meaning it believed the decision was in, or not inconsistent with, our best interests;
- provides that our general partner is entitled to make other decisions in “good faith” if it reasonably believes that the decision is in, or not inconsistent with, our best interests;
- provides generally that affiliated transactions and resolutions of conflicts of interest not approved by the Conflicts Committee and not involving a vote of unitholders must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or be “fair and reasonable” to us, as determined by our general partner in “good faith,” and that, in determining whether a transaction or resolution is “fair and reasonable,” our general partner may consider the totality of the relationships between the parties involved, including other transactions that may be particularly advantageous or beneficial to us; and
- provides that our general partner and its affiliates, officers and directors will be indemnified by the Partnership for any acts or omissions so long as such person acted in “good faith” and in a manner believed to be in, or not opposed to, the best interest of us and, with respect to any criminal proceeding, had no reasonable cause to believe its conduct was unlawful.

By purchasing a common unit, a common unitholder will be bound by the provisions in our Partnership Agreement, including the provisions discussed above.

The Board of Directors of our general partner, our general partner and its affiliates have conflicts of interest and limited fiduciary duties, which may permit them to favor their own interests.

ONEOK owns 100 percent of our general partner interest, and as a result of our public offerings of common units and units sold under our “at-the-market” equity program, ONEOK and its subsidiaries owned a 41.2 percent aggregate equity interest in us at December 31, 2015. Our Partnership Agreement limits any fiduciary duties owed by our general partner and ONEOK to those duties that are stated specifically in our Partnership Agreement. Although ONEOK, through the Board of Directors of our general partner, has an obligation to manage us in a manner that is in, or not inconsistent with, our best interests, the Board of Directors of ONEOK has a fiduciary duty to manage our general partner in a manner beneficial to ONEOK. Five of the eight members of the Board of Directors of our general partner are either members of ONEOK’s Board of Directors or executive management of ONEOK. Three independent members and one management member of the Board of Directors of our general partner also are members of ONEOK’s Board of Directors, with the management member being the only management member of ONEOK’s Board of Directors. Conflicts of interest may arise between ONEOK and its other affiliates and between us and our unitholders. In resolving these conflicts, our general partner may determine that the transaction is “fair and reasonable” to us, without the agreement of any other party, including the Audit or Conflicts Committees. In that regard, our general partner may favor its own interests and the interests of its other affiliates over the interests of our unitholders, as long as it does not take action that conflicts with our Partnership Agreement. These conflicts include, among others, the following situations:

- our general partner, which is owned by ONEOK, and the Board of Directors of our general partner are allowed to take into account the interests of parties other than us in resolving conflicts of interest, which has the effect of limiting their fiduciary duties to our unitholders;
- our Partnership Agreement limits the liability and reduces the fiduciary duties of the members of the Board of Directors of our general partner and also restricts the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty;
- the Board of Directors of our general partner determines the amount and timing of our cash reserves, asset purchases and sales, capital expenditures, borrowings and issuances of additional partnership securities, each of which can affect the amount of cash that is distributed to our unitholders;
- the Board of Directors of our general partner approves the amount and timing of any capital expenditures and determines whether they are maintenance capital expenditures or growth capital expenditures, which can affect the amount of cash that is distributed to our unitholders;
- the Board of Directors of our general partner may cause us to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make incentive distributions;
- our Partnership Agreement provides that costs incurred by the Board of Directors, our general partner and its affiliates in the conduct of our business are reimbursable by us;
- our Partnership Agreement does not restrict the members of the Board of Directors of our general partner from causing us to pay the Board of Directors, our general partner or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;
- our general partner may exercise its limited right to call and purchase common units, which right may be assigned or transferred to, among others, us or affiliates of the general partner, if the general partner and its affiliates own 80 percent or more of the common units; and
- the Board of Directors and Audit and Conflicts Committees of our general partner decide whether to retain separate counsel, accountants or others to perform services for us.

Our general partner and its affiliates may compete directly with us and have no obligation to present business opportunities to us.

ONEOK and its affiliates are not prohibited from owning assets or engaging in businesses that compete directly or indirectly with us. ONEOK may acquire, construct or dispose of additional midstream or other assets in the future without any obligation to offer us the opportunity to purchase or construct any of those assets. In addition, under our Partnership Agreement, the doctrine of corporate opportunity, or any analogous doctrine, will not apply to ONEOK and its affiliates. As a result, neither ONEOK nor any of its affiliates has any obligation to present business opportunities to us.

The control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer all, or any part of, its general partner interest to a third party without the consent of the unitholders. The members, shareholders or unitholders, as the case may be, of our new general partner may then be in a position to replace all or a portion of the directors of our general partner with their own choices and to possibly control the decisions made by the Board of Directors of our general partner.

Any reduction in our credit ratings could affect materially and adversely our business, financial condition, liquidity and results of operations.

Our senior unsecured long-term debt and commercial paper program have been assigned an investment-grade rating of "Baa2" (Negative) and Prime-2, respectively, by Moody's and "BBB" (Negative) and A-2, respectively, by S&P. We cannot provide assurance that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant. Specifically, if Moody's or S&P were to downgrade our long-term debt or commercial paper program rating, particularly below investment grade, our borrowing costs would increase, which would affect adversely our financial results, and our potential pool of investors and funding sources could decrease. Ratings from credit agencies are not recommendations to buy, sell or hold our securities. Each rating should be evaluated independently of any other rating.

Increases in interest rates may cause the market price of our common units to decline.

An increase in interest rates may cause a corresponding decline in demand for equity investments in general and in particular for yield-based equity investments such as our common units. Any such increase in interest rates or reduction in demand for our common units resulting from other more attractive investment opportunities may cause the trading price of our common units to decline.

We do not have the same flexibility as other types of organizations to accumulate cash and equity to protect against illiquidity in the future.

Unlike a corporation, our Partnership Agreement requires us to make quarterly distributions to our unitholders of all available cash reduced by any amounts of reserves for commitments and contingencies, including capital and operating costs and debt-service requirements, all of which are significant. The value of our units and other limited partner interests may decrease in correlation with decreases in the amount we distribute per unit. Accordingly, if we experience a liquidity problem in the future, we may not be able to issue more equity or incur more debt to recapitalize.

An event of default may require us to offer to repurchase certain of our senior notes or may impair our ability to access capital.

The indentures governing our senior notes include an event of default upon the acceleration of other indebtedness of $100 million or more. Such an event of default would entitle the trustee or the holders of 25 percent in aggregate principal amount of the outstanding senior notes to declare those senior notes immediately due and payable in full. We may not have sufficient cash on hand to repurchase and repay any accelerated senior notes, which may cause us to borrow money under our credit facilities or seek alternative financing sources to finance the repayments and repurchases. We could also face difficulties accessing capital or our borrowing costs could increase, impacting our ability to obtain financing for acquisitions or capital expenditures, to refinance indebtedness and to fulfill our debt obligations.

Our indebtedness could impair our financial condition and our ability to fulfill our obligations.

As of December 31, 2015, we had total indebtedness of approximately $7.3 billion. Our indebtedness could have significant consequences. For example, it could:

- make it more difficult for us to satisfy our obligations with respect to our senior notes and our other indebtedness, which could in turn result in an event of default on such other indebtedness or our senior notes;
- impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions or general business purposes;
- diminish our ability to withstand a downturn in our business or the economy;
- require us to dedicate a substantial portion of our cash flow from operations to debt-service payments, thereby reducing the availability of cash for working capital, capital expenditures, acquisitions, distributions to partners and general partnership purposes;
- limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and
- place us at a competitive disadvantage compared with our competitors that have proportionately less debt.

We are not prohibited under the indentures governing our senior notes from incurring additional indebtedness, but our debt agreements do subject us to certain operational limitations summarized in the next paragraph. Our incurrence of significant additional indebtedness would exacerbate the negative consequences mentioned above and could affect adversely our ability to repay our senior notes and other indebtedness.

Our debt agreements contain provisions that restrict our ability to finance future operations or capital needs or to expand or pursue our business activities. For example, certain of these agreements contain provisions that, among other things, limit our ability to make loans or investments, make material changes to the nature of our business, merge, consolidate or engage in asset sales, grant liens or make negative pledges. Certain agreements also require us to maintain certain financial ratios, which limit the amount of additional indebtedness we can incur. For example, our Partnership Credit Agreement contains a financial covenant requiring us to maintain a ratio of indebtedness to adjusted EBITDA (EBITDA, as defined in our Partnership Credit Agreement, adjusted for all noncash charges and increased for projected EBITDA from certain lender-approved capital expansion projects) of no more than 5.0 to 1. If we consummate one or more acquisitions in which the aggregate purchase price is $25 million or more, the allowable ratio of indebtedness to adjusted EBITDA will increase to 5.5 to 1 for the quarter in which the acquisition was completed and the two following quarters.

These restrictions could result in higher costs of borrowing and impair our ability to generate additional cash. Future financing agreements we may enter into may contain similar or more restrictive covenants.

If we are unable to meet our debt-service obligations, we could be forced to restructure or refinance our indebtedness, seek additional equity capital or sell assets. We may be unable to obtain financing, raise equity or sell assets on satisfactory terms, or at all.

Borrowings under our Partnership Credit Agreement and our senior notes are nonrecourse to ONEOK, and ONEOK does not guarantee our debt, commercial paper or other similar commitments.

We and the Intermediate Partnership have a holding company structure in which our subsidiaries conduct our operations and own our operating assets.

We and the Intermediate Partnership are holding companies, and our subsidiaries conduct all of our operations and own all of our operating assets. Neither we nor the Intermediate Partnership have significant assets other than the Partnership interests and the equity in our subsidiaries and other investments. As a result, our ability to make quarterly distributions and required payments on our indebtedness depends on the performance of our subsidiaries and their ability to distribute funds to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, credit facilities, applicable state partnership laws, and other laws and regulations, including FERC policies. If we are unable to obtain the funds necessary to make quarterly distributions or required payments on our indebtedness, we may be required to adopt one or more alternatives, such as refinancing the indebtedness or seeking alternative financing sources to fund the quarterly distributions and indebtedness payments.

We may issue additional common units or other units without unitholder approval, which would dilute unitholders' ownership interests.

Our general partner, without the approval of our unitholders, may cause us to issue an unlimited number of additional units. The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

- our unitholders' proportionate ownership interest in us will decrease;
- the distributions to our general partner related to its incentive distribution rights may increase and the distribution paid on each unit may decrease;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

Notwithstanding the foregoing, the issuance of equity securities ranking senior to the common units requires approval of a majority of the outstanding common units.

In addition, whenever we issue equity securities to any person other than our general partner and its affiliates, our general partner has the right, under the Partnership Agreement, which it may from time to time assign in whole or in part to any of its affiliates, to purchase additional partnership interests on the same terms as they are issued to other purchasers. This allows our general partner and its affiliates to maintain their proportionate partnership interest in us. No other unitholder has a similar right. Therefore, only the general partner may protect itself against dilution caused by issuance of additional equity interests.

Our general partner has a limited call right that may require unitholders to sell their common units at an undesirable time or price.

If at any time our general partner and its affiliates own 80 percent or more of the common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then-current market price. As a result, unitholders may be required to sell their common units at an undesirable time or price and may not receive any return on their investment. Unitholders also may incur a tax liability upon the sale of their units. Our general partner is not obligated to obtain a fairness opinion regarding the value of the common units to be repurchased by it upon exercise of the limited call right. There is no restriction in our Partnership Agreement that prevents our general partner from issuing additional common units and exercising its call right. If our general partner exercised its limited call right, the effect would be to take us private and, if the units subsequently were deregistered, we would no longer be subject to the reporting requirements of the Exchange Act.

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

Our Partnership Agreement restricts unitholders' voting rights by providing that any units held by a person or entity that owns 20 percent or more of our common units then outstanding, other than our general partner and its affiliates, cannot vote on any matter. Our Partnership Agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

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

A general partner of a limited partnership generally has unlimited liability for the obligations of the partnership, such as debts and environmental liabilities, except for those contractual obligations of the partnership that are made expressly without recourse to the general partner. We are organized as a limited partnership under Delaware law, and we and our subsidiaries conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. A unitholder could be held liable for our obligations to the same extent as a general partner if a court or government agency should determine that (i) we were conducting business in a state but had not complied with that state's limited partnership statute; or (ii) a unitholder's right to act with other unitholders to remove or replace our general partner, to approve some amendments to our Partnership Agreement or to take other actions under our Partnership Agreement constitute "control" of our business.

Unitholders may have liability to repay distributions.

Under certain circumstances, our unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act ("Delaware Act"), we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Liabilities to partners on account of their partnership interests and liabilities that are nonrecourse to the Partnership are not counted for purposes of determining whether a distribution is permitted.

Delaware law provides that for a period of three years from the date of an impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to us for the repayment of the distribution amount. Likewise, upon the winding up of the Partnership, in the event that (a) we do not distribute assets in the following order: (i) to creditors in satisfaction of their liabilities; (ii) to partners and former partners in satisfaction of liabilities for distributions owed under our Partnership Agreement; (iii) to partners for the return of their contributions; and finally (iv) to the partners in the proportions in which the partners share in distributions and (b) a limited partner knows at the time that the distribution violated the Delaware Act, then such limited partner will be liable for a period of three years from the impermissible distribution to repay the distribution under Section 17-804 of the Delaware Act.

A purchaser of common units becomes a limited partner and is liable for the obligations of the transferring limited partner to make contributions to us that are known to such purchaser of common units at the time it became a limited partner and for unknown obligations, if the liabilities could be determined from our Partnership Agreement.

A court may use fraudulent conveyance considerations to avoid or subordinate the Intermediate Partnership's guarantee of certain of our senior notes.

Various applicable fraudulent conveyance laws have been enacted for the protection of creditors. In a Florida bankruptcy case, a court ruled that certain guarantees were unenforceable due to fraudulent conveyance laws, among other factors. Similarly, a court may use fraudulent conveyance laws to subordinate or avoid the guarantee of certain of our senior notes issued by the Intermediate Partnership. It is also possible that under certain circumstances a court could hold that the direct obligations of the Intermediate Partnership could be superior to the obligations under that guarantee.

A court could avoid or subordinate the Intermediate Partnership's guarantee of certain of our senior notes in favor of the Intermediate Partnership's other debts or liabilities to the extent that the court determined either of the following were true at the time the Intermediate Partnership issued the guarantee:

- the Intermediate Partnership incurred the guarantee with the intent to hinder, delay or defraud any of its present or future creditors or the Intermediate Partnership contemplated insolvency with a design to favor one or more creditors to the total or partial exclusion of others; or
- the Intermediate Partnership did not receive fair consideration or reasonable equivalent value for issuing the guarantee, and, at the time it issued the guarantee, the Intermediate Partnership:
    - was insolvent or rendered insolvent by reason of the issuance of the guarantee;
    - was engaged or about to engage in a business or transaction for which its remaining assets constituted unreasonably small capital; or
    - intended to incur, or believed that it would incur, debts beyond its ability to pay such debts as they matured.

The measure of insolvency for purposes of the foregoing will vary depending upon the law of the relevant jurisdiction. Generally, however, an entity would be considered insolvent for purposes of the foregoing if:

- the sum of its debts, including contingent liabilities, were greater than the fair saleable value of all of its assets at a fair valuation;
- the present fair saleable value of its assets was less than the amount that would be required to pay its probable liability on its existing debts, including contingent liabilities, as they become absolute and mature; or
- it could not pay its debts as they become due.

Among other things, a legal challenge of the Intermediate Partnership's guarantee of certain of our senior notes on fraudulent conveyance grounds may focus on the benefits, if any, realized by the Intermediate Partnership as a result of our issuance of such senior notes. To the extent the Intermediate Partnership's guarantee of certain of our senior notes is avoided as a result of fraudulent conveyance or held unenforceable for any other reason, the holders of such senior notes would cease to have any claim in respect of the guarantee.

Our operating cash flow is derived partially from cash distributions we receive from our unconsolidated affiliates.

Our operating cash flow is derived partially from cash distributions we receive from our unconsolidated affiliates, as discussed in Note M of the Notes to Consolidated Financial Statements. The amount of cash that our unconsolidated affiliates can distribute principally depends upon the amount of cash flow these affiliates generate from their respective operations, which may fluctuate from quarter to quarter. We do not have any direct control over the cash distribution policies of our unconsolidated affiliates. This lack of control may contribute to our not having sufficient available cash each quarter to continue paying distributions at our current levels.

Additionally, the amount of cash that we have available for cash distribution depends primarily upon our cash flow, including cash flow from financial reserves and working capital borrowings, and is not solely a function of profitability, which will be affected by noncash items such as depreciation, amortization and provisions for asset impairments. As a result, we may be able to make cash distributions during periods when we record losses and may not be able to make cash distributions during periods when we record net income.

The credit and risk profile of ONEOK Partners GP and its owner could affect adversely our credit ratings and profile.

The credit and business risk profiles of ONEOK Partners GP, and of ONEOK as the owner of ONEOK Partners GP, may be factors in credit evaluations of us as a publicly traded limited partnership due to the significant influence of ONEOK Partners GP and ONEOK over our business activities, including our cash distributions, acquisition strategy and business risk profile. Another factor that may be considered is the financial condition of ONEOK Partners GP and its owner, including the degree of their financial leverage and their dependence on cash flow from the Partnership to service their indebtedness. ONEOK is dependent on the cash distributions from its general and limited partner equity interests in us to service indebtedness. Any distributions by us to ONEOK will be made only after satisfying our then current obligations to our creditors. Although we have taken certain steps in our organizational structure, financial reporting and contractual relationships to reflect the separateness of us from the entity that controls ONEOK Partners GP (*i.e*., ONEOK), our credit ratings and business-risk profile could be affected adversely if the ratings and risk profiles of such entities were viewed as substantially lower or riskier than ours.

The right to receive payments on our outstanding debt securities and subsidiary guarantees is unsecured and will be effectively subordinated to our existing and future secured indebtedness as well as to any existing and future indebtedness of our subsidiaries that do not guarantee the senior notes.

Our debt securities are effectively subordinated to claims of our secured creditors, and the guarantees are effectively subordinated to the claims of our secured creditors as well as the secured creditors of our subsidiary guarantors. Although many of our operating subsidiaries have guaranteed such debt securities, the guarantees are subject to release under certain circumstances, and we may have subsidiaries that are not guarantors. In that case, the debt securities effectively would be subordinated to the claims of all creditors, including trade creditors and tort claimants, of our subsidiaries that are not guarantors. In the event of the insolvency, bankruptcy, liquidation, reorganization, dissolution or winding up of the business of a subsidiary that is not a guarantor, creditors of that subsidiary would generally have the right to be paid in full before any distribution is made to us or the holders of the debt securities.

The ability to transfer our debt securities may be limited by the absence of a trading market.

We do not currently intend to apply for listing of our debt securities on any securities exchange or stock market. The liquidity of any market for our debt securities will depend on the number of holders of those debt securities, the interest of securities dealers in making a market in those debt securities and other factors. Accordingly, we can give no assurance as to the development or liquidity of any market for the debt securities.

TAX RISKS

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

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this matter.

Despite the fact that we are a limited partnership under Delaware law, we will be treated as a corporation for federal income tax purposes unless we satisfy a “qualifying income” requirement. Based upon our current operations, we believe we satisfy the qualifying income requirement. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as a corporate entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35 percent, and would likely pay additional state and local income taxes at varying rates. Distributions to our unitholders would generally be taxed again as corporate dividends, and no income, gains, losses or deductions would flow through to our unitholders. Because an income tax would be imposed upon us as a corporation, the cash available for distributions to our common unitholders would be reduced substantially. Therefore, if we were treated as a corporation for federal income tax purposes, there would be a material reduction in the anticipated free cash flow and after-tax return to our common unitholders, likely causing a substantial reduction in the value of our common units.

In addition, changes in current state law may subject us to additional entity-level taxation by individual states. Because of widespread state budget deficits and other reasons, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. For example, we are subject to an entity-level Texas franchise tax. Imposition of any similar taxes by any other state may reduce substantially the cash available for distribution to our common unitholders and, therefore, impact negatively the value of an investment in our common units.

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

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

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. For example, from time to time, the President of the United States and members of the United States Congress propose and consider substantive changes to the existing federal income tax laws that could affect the tax treatment of certain publicly traded partnerships. Further, the U.S. Treasury Department and the IRS issued proposed regulations under Section 7704(d)(1)(E) of the Income Tax Code on May 5, 2015, interpreting the scope of qualifying income for publicly traded partnerships by providing industry-specific guidance with respect to activities that will generate qualifying income for purposes of the qualifying income requirement. The proposed regulations, once issued in final form, may change interpretations of the current law relating to the characterization of income as qualifying income and could modify the amount of our gross income we are able to treat as qualifying income for purposes of the qualifying income requirement.

Any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. We are unable to predict whether any previously considered changes or any other proposals will ultimately be enacted. Any such changes could impact negatively the value of an investment in our common units and the amount of cash available for distribution to our unitholders.

An IRS contest of the federal income tax positions we take may affect adversely the market for our common units, and the costs of any IRS contest will reduce our cash available for distribution to our unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes. The IRS may adopt positions that differ from the federal income tax positions we take, and such positions may not ultimately be sustained. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may affect adversely the taxable income reported to our unitholders and the income taxes they are required to pay. As a result, any such contest with the IRS may affect materially and adversely the market for our common units and the price at which they trade. In addition, the costs of any such contest with the IRS will be borne indirectly by our unitholders and our general partner because such costs will reduce our cash available for distribution.

Recently enacted legislation, applicable to partnership tax years beginning after 2017, alters the procedures for auditing large partnerships and for assessing and collecting taxes due (including penalties and interest) as a result of a partnership-level federal income tax audit. Under the new rules, unless we are eligible to, and do, elect to issue revised Schedules K-1 to our partners with respect to an audited and adjusted return, the IRS may assess and collect taxes (including any applicable penalties and interest) directly from us in the year in which the audit is completed. If we are required to pay taxes, penalties and interest as a result of audit adjustments, cash available for distribution to our unitholders may be substantially reduced. In addition, because payment would be due for the taxable year in which the audit is completed, unitholders during that taxable year would bear the expense of the adjustment even if they were not unitholders during the audited tax year.

A unitholder’s share of our income may be taxable to the unitholder for federal income tax purposes even if the unitholder does not receive any cash distributions from us.

Because our unitholders may be treated as partners to whom we will allocate taxable income that could be different in amount than the cash we distribute, a unitholder’s share of our taxable income will be taxable to the unitholder, which may require the payment of federal income taxes and, in some cases, state and local income taxes on the unitholder’s share of our taxable income, even if the unitholder receives no cash distributions from us. A unitholder may not receive cash distributions from us equal to the unitholder’s share of our taxable income or even equal to the actual tax liability that results from that income.

In the event we issue additional units or engage in certain other transactions in the future, the allocable share of nonrecourse liabilities allocated to the unitholders will be recalculated to take into account our issuance of any additional units. Any reduction in a unitholder’s share of our nonrecourse liabilities will be treated as a distribution of cash to that unitholder and will result in a corresponding tax basis reduction in a unitholder’s units. A deemed cash distribution may, under certain circumstances, result in the recognition of taxable gain by a unitholder, to the extent that the deemed cash distribution exceeds such unitholder’s tax basis in its units.

In addition, the federal income tax liability of a unitholder could be increased if we dispose of assets or make a future offering of units and use the proceeds in a manner that does not produce substantial additional deductions, such as to repay indebtedness currently outstanding or to acquire property that is not eligible for depreciation or amortization for federal income tax purposes or that is depreciable or amortizable at a rate significantly slower than the rate currently applicable to our assets.

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

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

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

Investment in common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts and non-United States persons, raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including individual retirement accounts and other retirement plans, may be taxable to them as "unrelated business taxable income." Distributions to non-United States persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-United States persons will be required to file United States federal income tax returns and pay tax on their share of our taxable income. A unitholder that is a tax-exempt entity or a non-U.S. person should consult a tax advisor before investing in our common units.

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

Because we cannot match transferors and transferees of common units, we have adopted depreciation and amortization positions that may not conform to all aspects of existing Treasury regulations. A successful IRS challenge to those positions could affect adversely the amount of tax benefits available to unitholders. It also could affect the timing of these tax benefits or the amount of gain from a unitholder's sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to a unitholder's tax returns.

We may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction for federal income tax purposes between transferors and transferees of our common units each month based upon the ownership of our units as of the close of business on the last day of the preceding month, instead of on the basis of the date a particular unit is transferred. Although recently issued final Treasury regulations allow publicly traded partnerships to use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders, such tax items must be prorated on a daily basis, and these regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to successfully challenge our proration method, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

Unitholders may be subject to state and local taxes and return-filing requirements as a result of investing in our common units.

In addition to federal income taxes, unitholders may be subject to other taxes, including state and local income taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property, even if the unitholder does not live in any of those jurisdictions. Unitholders may be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions and may be subject to penalties for failure to comply with those requirements. As we make acquisitions or expand our business, we may own assets or conduct business in additional states or foreign countries that impose a personal income tax or an entity level tax.

We determine our depreciation and cost-recovery allowances using federal income tax methods and may use methods that result in the largest deductions being taken in the early years after assets are placed in service. Some of the states in which we do business or own property may not conform to these federal depreciation methods. A successful challenge to these methods could affect adversely the amount of taxable income or loss being allocated to our unitholders for state tax purposes. It also could affect the amount of gain from a unitholder's sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to the unitholder's state tax returns. It is each unitholder's responsibility to file all United States federal, state and local tax returns and foreign tax returns, as applicable. Our legal counsel has not rendered an opinion on the state and local tax consequences of an investment in our common units.

Some of the states in which we do business or own property may require us to, or we may elect to, withhold a percentage of income from amounts to be distributed to a unitholder who is not a resident of the state. Withholding the amount of which may be greater or less than a particular unitholder's income tax liability to the state generally does not relieve the nonresident unitholder from the obligation to file an income tax return. Amounts withheld may be treated as if distributed to unitholders for purposes of determining the amounts distributed by us.

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

We will be considered to have technically terminated our partnership for federal income tax purposes if there is a sale or exchange of 50 percent or more of the total interests in our capital and profits within a 12-month period. For purposes of determining whether the 50 percent threshold has been met, multiple sales of the same interest will be counted only once. Our technical termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1 if relief was not available, as described below) for one fiscal year and could also result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may result in more than 12 months of our taxable income or loss being included in the unitholder's taxable income for the year of termination. Our technical termination would not affect our classification as a partnership for federal income tax purposes, but instead, after our termination, we would be treated as a new partnership for federal income tax purposes. If treated as a new partnership, we would be required to make new tax elections and could be subject to penalties if we are unable to determine that a technical termination occurred.

The IRS has announced a publicly traded partnership technical termination relief procedure, whereby, if a publicly traded partnership that has a technical termination requests and the IRS grants special relief, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the year, notwithstanding two partnership tax years resulting from the technical termination.

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

In determining the items of income, gain, loss and deduction allocable to our unitholders, we must routinely determine the fair market value of our respective assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we make fair market value estimates using a methodology based on the market value of our common units as a means to measure the fair market value of our respective assets. The IRS may challenge these valuation methods and the resulting allocations of income, gain, loss and deduction.

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

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

Because a unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of the loaned units, the unitholder may no longer be treated for federal income tax purposes as a partner with respect to those units during the period of the loan to the short seller, and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder, and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to consult a tax advisor to discuss whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not applicable.

ITEM 2. PROPERTIES

Natural Gas Gathering and Processing

Property - Our Natural Gas Gathering and Processing segment owns the following assets:

- approximately 11,300 miles and 7,600 miles of natural gas gathering pipelines in the Mid-Continent and Rocky Mountain regions, respectively;
- nine natural gas processing plants with approximately 785 MMcf/d of processing capacity in the Mid-Continent region, and 11 natural gas processing plants with approximately 965 MMcf/d of processing capacity in the Rocky Mountain region; and
- approximately 15 MBbl/d of natural gas liquids fractionation capacity at various natural gas processing plants in the Mid-Continent and Rocky Mountain regions.

As discussed further in "Growth Projects" in our Natural Gas Gathering and Processing segment's discussion in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, we also are constructing the following:

- one additional natural gas processing plant in the Rocky Mountain region, which will provide approximately 80 MMcf/d of combined processing capacity; and
- two de-ethanizers in the Rocky Mountain region, which will remove ethane from the natural gas stream, which we expect to be sold under a long-term contract to a customer who plans to transport the ethane on a third-party pipeline.

Utilization - The utilization rates for our natural gas processing plants were approximately 76 percent and 84 percent for 2015 and 2014, respectively. We calculate utilization rates using a weighted-average approach, adjusting for the dates that assets were placed in service.

Natural Gas Liquids

Property - Our Natural Gas Liquids segment owns the following assets:

- approximately 2,800 miles of non-FERC-regulated natural gas liquids gathering pipelines with peak capacity of approximately 800 MBbl/d;
- approximately 170 miles of non-FERC-regulated natural gas liquids distribution pipelines with peak transportation capacity of approximately 66 MBbl/d;
- approximately 4,300 miles of FERC-regulated natural gas liquids gathering pipelines with peak capacity of approximately 683 MBbl/d;
- approximately 4,200 miles of FERC-regulated natural gas liquids and refined petroleum products distribution pipelines with peak capacity of 993 MBbl/d;
- one natural gas liquids fractionator in Oklahoma with operating capacity of approximately 210 MBbl/d, two natural gas liquids fractionators in Kansas with combined operating capacity of 280 MBbl/d and two natural gas liquids fractionators in Texas with combined operating capacity of 150 MBbl/d;
- 80 percent ownership interest in one natural gas liquids fractionator in Texas with our proportional share of operating capacity of approximately 128 MBbl/d;
- interest in one natural gas liquids fractionator in Kansas with our proportional share of operating capacity of approximately 11 MBbl/d;
- one isomerization unit in Kansas with operating capacity of 9 MBbl/d;
- six natural gas liquids storage facilities in Oklahoma, Kansas and Texas with operating storage capacity of approximately 23.2 MMBbl;
- eight natural gas liquids product terminals in Missouri, Nebraska, Iowa and Illinois;

- above- and below-ground storage facilities associated with our FERC-regulated natural gas liquids pipeline operations in Iowa, Illinois, Nebraska and Kansas with combined operating capacity of 978 MBbl; and
- one ethane/propane splitter in Texas with operating capacity of 32 MBbl/d of purity ethane and 8 MBbl/d of propane.

In addition, we lease approximately 2.5 MMBbl of combined NGL storage capacity at facilities in Kansas and Texas and have access to 60 MBbl/d of natural gas liquids fractionation capacity in Texas through a fractionation service agreement.

As discussed further in "Growth Projects" in our Natural Gas Liquids segment's discussion in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, we also have a 25 MBbl/d expansion of our Bakken NGL Pipeline and additional NGL infrastructure in the Rocky Mountain region in various stages of construction.

Utilization - The utilization rates for our various assets, including leased assets, have been impacted by ethane rejection. The utilization rates for 2015 and 2014, respectively, were as follows:

- our non-FERC-regulated natural gas liquids gathering pipelines were approximately 65 percent and 62 percent;
- our FERC-regulated natural gas liquids gathering pipelines were approximately 75 percent and 79 percent;
- our FERC-regulated natural gas liquids distribution pipelines were approximately 43 percent and 47 percent;
- our natural gas liquids fractionators were approximately 66 percent and 70 percent; and
- our average contracted natural gas liquids storage volumes were approximately 66 percent and 69 percent of storage capacity.

We calculate utilization rates using a weighted-average approach, adjusting for the dates that assets were placed in service. Our fractionation utilization rate reflects approximate proportional capacity associated with our ownership interests.

Natural Gas Pipelines

Property - Our Natural Gas Pipelines segment owns the following assets:

- approximately 1,500 miles of FERC-regulated interstate natural gas pipelines with approximately 3.2 Bcf/d of peak transportation capacity;
- approximately 5,200 miles of state-regulated intrastate transmission pipelines with peak transportation capacity of approximately 3.2 Bcf/d; and
- approximately 55.4 Bcf of total active working natural gas storage capacity.

Our storage includes four underground natural gas storage facilities in Oklahoma, two underground natural gas storage facilities in Kansas and two underground natural gas storage facilities in Texas.

As discussed further in "Growth Projects" in our Natural Gas Pipelines segment's discussion in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, we also are constructing or plan to construct the following:

- one intrastate transmission pipeline in the Permian Basin through a 50-50 joint venture, which will provide approximately 640 MMcf/d of transportation capacity; and
- one wholly owned intrastate transmission pipeline expansion in the Permian Basin, which will provide 260 MMcf/d of incremental transportation capacity.

Utilization - Our natural gas pipelines were approximately 92 percent subscribed in 2015 and 91 percent subscribed in 2014, and our natural gas storage facilities were 71 percent subscribed in 2015 and 76 percent subscribed in 2014.

ITEM 3. LEGAL PROCEEDINGS

We are a party to various litigation matters and claims that have arisen in the normal course of our operations. While the results of litigation and claims cannot be predicted with certainty, we believe the reasonably possible losses from such matters, individually and in the aggregate, are not material. Additionally, we believe the probable final outcome of such matters will not have a material adverse effect on our consolidated results of operations, financial position or cash flows.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT’S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

MARKET INFORMATION AND HOLDERS

Our equity consists of a 2 percent general partner interest and a 98 percent limited partner interest. Our limited partner interests are represented by our common units, which are listed on the NYSE under the trading symbol “OKS,” and our Class B limited partner units. The following table sets forth the high and low closing prices of our common units for the periods indicated:

	Year Ended December 31, 2015		Year Ended December 31, 2014	
	High	Low	High	Low
First Quarter	**$ 46.05**	**$ 38.00**	$ 57.09	$ 50.10
Second Quarter	**$ 43.35**	**$ 34.00**	$ 58.60	$ 53.78
Third Quarter	**$ 35.24**	**$ 27.79**	$ 59.43	$ 54.20
Fourth Quarter	**$ 34.93**	**$ 22.73**	$ 56.11	$ 38.23

At February 16, 2016, there were 507 holders of record of our 212,837,980 outstanding common units. ONEOK and its affiliates own all of the Class B units, 41,344,581 common units and the entire 2 percent general partner interest in us, which together constituted a 41.2 percent ownership interest in us at December 31, 2015.

CASH DISTRIBUTIONS

The following table sets forth the quarterly cash distribution declared and paid on each of our common and Class B units during the periods indicated:

Declared for Quarter Ending	Distribution Per Unit	Date Declared	Date Paid
December 31, 2015	$ 0.790	January 21, 2016	February 12, 2016
September 30, 2015	$ 0.790	October 21, 2015	November 13, 2015
June 30, 2015	$ 0.790	July 23, 2015	August 14, 2015
March 31, 2015	$ 0.790	April 16, 2015	May 15, 2015
December 31, 2014	$ 0.790	January 15, 2015	February 13, 2015
September 30, 2014	$ 0.775	October 23, 2014	November 14, 2014
June 30, 2014	$ 0.760	July 25, 2014	August 14, 2014
March 31, 2014	$ 0.745	April 18, 2014	May 15, 2014
December 31, 2013	$ 0.730	January 16, 2014	February 14, 2014

CASH DISTRIBUTION POLICY

We make distributions to our partners with respect to each calendar quarter in an amount equal to 100 percent of available cash, as defined in our Partnership Agreement, within 45 days following the end of each quarter. Available cash generally consists of all cash receipts less adjustments for cash disbursements and net changes to reserves. Available cash will generally be distributed to our general partner and limited partners according to their partnership percentages of 2 percent and 98 percent, respectively. Our general partner’s percentage interest in quarterly distributions is increased after certain specified target levels are met during the quarter. Under the incentive distribution provisions, our general partner receives:

- 15 percent of amounts distributed in excess of $0.3025 per unit;
- 25 percent of amounts distributed in excess of $0.3575 per unit; and
- 50 percent of amounts distributed in excess of $0.4675 per unit.

Our Class B limited partner units are entitled to receive increased quarterly distributions equal to 110 percent of the distributions paid with respect to our common units. ONEOK, as the sole holder of our Class B limited partner units, has waived its right to receive the increased quarterly distributions on the Class B units. ONEOK retains the option to withdraw its waiver of increased distributions on our Class B units at any time by giving us no less than 90 days advance notice. Any such withdrawal of the waiver will be effective with respect to any distribution on the Class B units declared or paid on or after the 90 days following delivery of the notice.

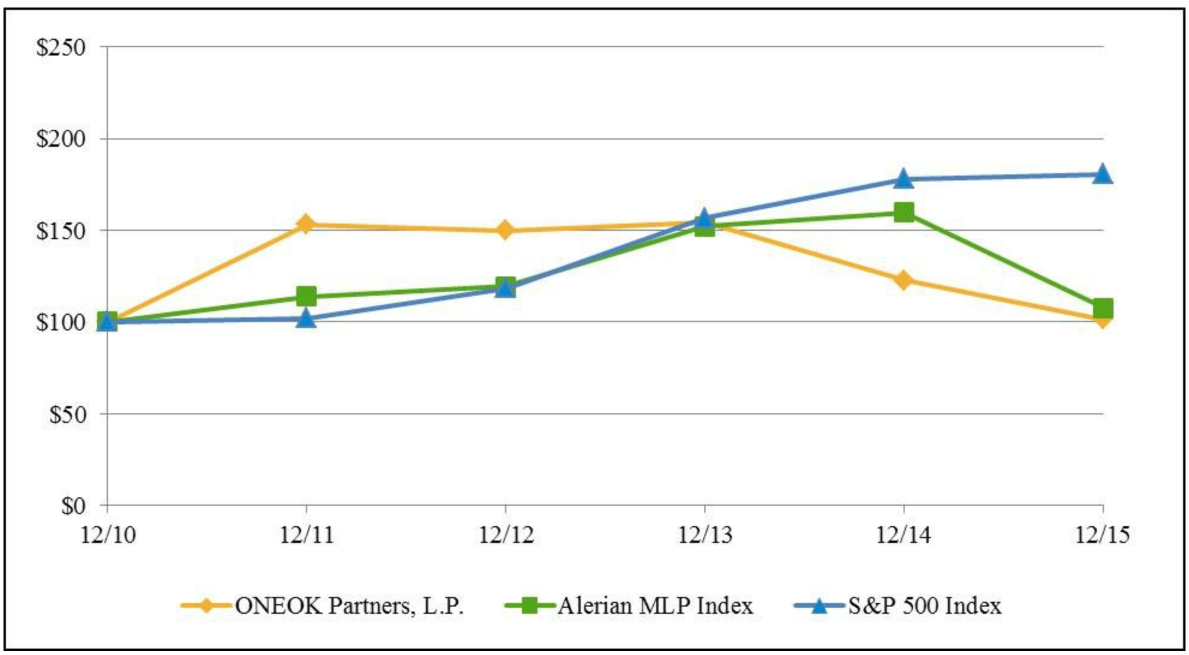
If our common unitholders vote at any time to remove ONEOK or its affiliates as our general partner, quarterly distributions payable on the Class B limited partner units would increase to 123.5 percent of the distributions payable with respect to the common units, and distributions payable upon liquidation of the Class B limited partner units would increase to 123.5 percent of the distributions payable with respect to the common units.

We paid cash distributions to our general and limited partners of $1.2 billion, $1.1 billion and $909.7 million for 2015, 2014 and 2013, respectively, which included an incentive distribution to our general partner of $371.5 million, $305.0 million and $251.7 million for 2015, 2014 and 2013, respectively. Additional information about our cash distributions is included in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation, under "Liquidity and Capital Resources," and Item 13, Certain Relationships and Related Transactions, and Director Independence.

PERFORMANCE GRAPH

The following performance graph compares the performance of our common units with the S&P 500 Index and the Alerian MLP Index during the period beginning on December 31, 2010, and ending on December 31, 2015. The graph assumes a $100 investment in our common units and in each of the indices at the beginning of the period and a reinvestment of distributions/dividends paid on such investments throughout the period.

Value of $100 Investment, Assuming Reinvestment of Distributions/Dividends,
at December 31, 2010, and at the End of Every Year Through December 31, 2015,
in ONEOK Partners, L.P., the S&P 500 Index and the Alerian MLP Index



	Cumulative Total Return				
	Years Ended December 31,				
	2011	2012	2013	2014	2015
ONEOK Partners, L.P.	$ 153.12	$ 149.82	$ 154.02	$ 122.55	**$ 101.56**
Alerian MLP Index (a)	$ 113.83	$ 119.32	$ 152.25	$ 159.51	**$ 107.63**
S&P 500 Index	$ 102.08	$ 118.39	$ 156.70	$ 178.10	**$ 180.56**

(a) - The Alerian MLP Index measures the composite performance of the 50 most prominent energy master limited partnerships.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth our selected financial data for the periods indicated:

	Years Ended December 31,				
	2015	2014	2013	2012	2011
	(*Millions of dollars, except per unit data*)				
Revenues	**$ 7,761.1**	$ 12,191.7	$ 11,869.3	$ 10,182.2	$ 11,322.6
Net income	**$ 597.9**	$ 911.3	$ 804.0	$ 888.4	$ 830.9
Net income attributable to ONEOK Partners, L.P.	**$ 589.5**	$ 910.3	$ 803.6	$ 888.0	$ 830.3
Limited partners' net income per unit	**$ 0.73**	$ 2.33	$ 2.35	$ 3.04	$ 3.35
Distributions paid per common unit (a)	**$ 3.160**	$ 3.010	$ 2.870	$ 2.590	$ 2.325
Total assets	**$ 14,927.6**	$ 14,600.4	$ 12,824.2	$ 10,927.4	$ 8,921.7
Long-term debt, including current maturities	**$ 6,803.0**	$ 6,011.9	$ 6,014.1	$ 4,779.5	$ 3,851.7

(a) - Class B unitholders received the same distribution as common unitholders.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with Item 1, Business, our audited Consolidated Financial Statements and the Notes to Consolidated Financial Statements in this Annual Report.

RECENT DEVELOPMENTS

Please refer to the "Financial Results and Operating Information" and "Liquidity and Capital Resources" sections of Management's Discussion and Analysis of Financial Condition and Results of Operations, and our Consolidated Financial Statements and Notes to Consolidated Financial Statements in this Annual Report for additional information.

Due in part to the rapid growth in crude oil and natural gas production in the United States, the global supply of crude oil and natural gas exceeded demand and led to a dramatic fall in commodity prices beginning in the fourth quarter 2014. Lower crude oil and natural gas prices persisted throughout 2015 and are expected to remain low in 2016. The production growth and decline in crude oil prices have also contributed to lower NGL product prices, as well as narrow NGL product price differentials.

WTI crude oil prices declined to an average of approximately $50.00 per barrel in 2015, compared with prices averaging approximately $93.00 per barrel in 2014. NYMEX natural gas prices also declined to an average of approximately $2.60 per MMBtu in 2015, compared with prices averaging approximately $4.30 per MMBtu in 2014. OPIS Conway propane prices averaged less than $0.41 per gallon in 2015, compared with prices averaging more than $1.10 per gallon in 2014. At December 31, 2015, prices for WTI crude oil, NYMEX natural gas and OPIS Conway propane declined to approximately $35.00 per barrel, $2.30 per MMBtu and $0.33 per gallon, respectively, and remained weak into early 2016.

We have mitigated partially our exposure to the current commodity price environment by growing our fee-based business. We have a predominantly fee-based business in our Natural Gas Liquids and Natural Gas Pipelines segments and, historically to a lesser extent, in our Natural Gas Gathering and Processing segment. In 2015, however, our Natural Gas Gathering and Processing segment restructured many POP with fee contracts associated with a significant amount of our gathered volumes to increase the fee-based component and will continue to seek opportunities to similarly restructure additional contracts in 2016. These restructured contracts favorably impacted our 2015 results, and we expect to receive the full benefit of the improved earnings from these contracts in our 2016 financial results. In the fourth quarter 2015, our Natural Gas Gathering and Processing segment's fee revenues averaged $0.55 per MMBtu, compared with an average of $0.36 per MMBtu in 2014. As a result of these restructured contracts, we expect our Natural Gas Gathering and Processing segment's fee-based earnings to increase significantly to more than 75 percent in 2016 and our consolidated fee-based earnings to increase to approximately 85 percent in 2016. To further mitigate the impact of lower commodity prices, we have hedged a significant portion of our Natural Gas Gathering and Processing segment's expected equity volumes for 2016 and 2017. Our Natural Gas Liquids and Natural Gas Pipelines segments continue to provide primarily fee-based services, and many of the contracts in these segments include fixed fee, minimum volume or firm demand charge agreements that provide a minimum level of revenues regardless of commodity prices or volumetric throughput.

The current weakened commodity price environment, resulting from factors beyond our control, is creating challenges for our crude oil and natural gas producer customers and resulted in decreased drilling activity in 2015, compared with 2014. In the Williston Basin, the number of rigs drilling on acreage dedicated to us decreased from approximately 80 rigs in January 2015, to approximately 30 rigs in December 2015. Despite the sustained lower crude oil, natural gas and NGL prices and reduced capital spending by producers, we continue to expect demand for midstream services and infrastructure development to be driven by producers who need to connect production with end-use markets where current infrastructure is insufficient or nonexistent. Our natural gas and NGL volumes increased in 2015, particularly in the Williston Basin, as producers are focusing their drilling in the most productive areas and are using more efficient drilling and completion techniques. We expect this lower commodity price environment to continue in 2016, which will impact our net realized prices for natural gas, NGLs and condensate, as well as our financial results. If the low commodity price environment persists for a prolonged period or prices decline further, volumes across our assets may grow more slowly than in the past or decline.

Although drilling has slowed, many of our customers continue to drill new wells in the most productive areas, and improvements in drilling and completion technology are resulting in higher volumes from the wells that are completed. These new technologies, such as multi-well pads and more efficient drilling rigs, are resulting in lower drilling and completion costs, which are mitigating partially the lower commodity prices for our producer customers. In addition, new wells drilled using horizontal drilling technologies tend to produce volumes at higher initial production rates resulting generally in higher initial decline rates than conventional vertical wells; however, the decline rates flatten out over time. A significant portion of our Williston Basin gathering and processing assets are in the most productive areas, which typically produce at higher initial production rates compared with other areas, have the highest natural gas content and have slower natural gas declines than crude oil. We expect our natural gas gathered and processed volumes in the Williston Basin to continue to grow in 2016, despite expected reductions in producer drilling activity. The significant drilling activity in recent years in the Williston Basin has caused natural gas production to exceed the capacity of existing natural gas gathering and processing infrastructure, which results in the flaring of natural gas (the controlled burning of natural gas at the wellhead) by producers. We expect to capture a substantial amount of natural gas currently being flared by producers due to an additional processing plant and compression projects that were placed in service in late 2015 and projects that are expected to be completed in 2016. Additionally, we expect to benefit from production from new wells on our dedicated acreage in the Williston Basin that have been drilled previously but have not yet been completed or connected to our system by expanding our natural gas gathering and processing and natural gas liquids gathering infrastructure in the Williston Basin.

We expect ethane rejection to persist at current levels, which have exceeded 150 MBbl/d on our natural gas liquids system during 2015, until ethylene producers increase their capacity to consume additional ethane feedstock volumes through plant modifications, plant expansions and the completion of announced new world-scale ethylene production projects, which are anticipated to begin coming on line in 2017. Ethane rejection is expected to continue to have a significant impact on our financial results into 2017.

Beginning in June 2015, our Natural Gas Gathering and Processing segment reduced its level of ethane rejection in the Williston Basin to alleviate downstream NGL product specification issues, which offsets partially the financial impact of ethane rejection. We expect this decreased level of ethane rejection to continue throughout 2016. In addition, our Natural Gas Liquids segment's integrated assets enable us to mitigate partially this impact through minimum volume commitments, contract modifications that vary fees for ethane and other NGL products, and our ability to utilize the transportation capacity made available due to ethane rejection to capture additional NGL location price differentials, when they exist, in our optimization activities.

Growth Projects - In 2015, crude oil and natural gas producers continued to drill for crude oil and NGL-rich natural gas in many regions where we have operations, including in the Bakken Shale and Three Forks formations in the Williston Basin; in the Cana-Woodford Shale, Woodford Shale, Springer Shale, Stack and SCOOP areas in the Mid-Continent region; and in the Permian Basin. In response to this continued production of crude oil, natural gas and NGLs, and higher demand for NGL products from the petrochemical industry, we have completed growth projects and acquisitions in these regions. In addition, our current projects are expected to expand our natural gas gathering and processing and natural gas liquids gathering infrastructure in the Williston Basin to capture natural gas currently being flared by producers. Through our Roadrunner joint venture, we are constructing a pipeline to transport natural gas from the Permian Basin in West Texas to the Mexican border near El Paso, Texas. The Roadrunner pipeline will connect with our existing natural gas pipeline and storage infrastructure in Texas and, together with our WesTex intrastate natural gas transmission pipeline expansion project, is expected to create a platform for future opportunities to deliver natural gas supply to Mexico. The execution of these capital investments aligns with our strategy to generate consistent growth and sustainable earnings. Our contractual commitments from crude oil and natural gas producers, natural gas processors and electric generators are expected to provide incremental cash flows and long-term fee-based earnings.

While reduced crude oil and natural gas producer drilling activity is slowing supply growth, we expect to complete our previously announced projects to meet crude oil and natural gas producers' demand for our gathering, processing, fractionation and transportation services. We have suspended capital expenditures for certain natural gas processing plants and related infrastructure to align with the needs of our customers. We could resume our suspended capital-growth projects when market conditions improve and our customers' needs change. In 2016, we expect lower capital spending, compared with spending levels from 2013 through 2015, due to the current commodity price environment and our alignment of capital-growth projects with the needs of our customers. If the current commodity price environment persists for a prolonged period, it may further impact the timing or demand for additional infrastructure projects or growth opportunities in the future.

WesTex Transmission Pipeline Expansion - In July 2015, we announced plans to invest $70 million to $100 million to expand our WesTex intrastate natural gas pipeline system in the Permian Basin in our Natural Gas Pipelines segment. WesTex, which had qualifying open season bids in excess of 500 MMcf/d, plans to utilize 240 MMcf/d of existing capacity and create additional capacity by expanding its system by 260 MMcf/d by the first quarter 2017. This expansion project is supported by firm demand charge transportation agreements and is complementary to our recently announced Roadrunner joint venture pipeline project discussed below.

See additional discussion of our other growth projects in the "Financial Results and Operating Information" section in our Natural Gas Gathering and Processing, Natural Gas Liquids and Natural Gas Pipelines segments.

Roadrunner - In March 2015, we entered into a 50-50 joint venture with a subsidiary of Fermaca Infrastructure B.V. (Fermaca), a Mexico City-based natural gas infrastructure company, to construct a pipeline to transport natural gas from the Permian Basin in West Texas to the Mexican border near El Paso, Texas. The pipeline will connect with our existing natural gas pipeline and storage infrastructure in Texas. These integrated assets are also expected to provide markets in Mexico access to upstream supply basins in West Texas and the Mid-Continent region, which adds location and price diversity to their supply mix and supports the plan of Mexico's national electric utility, Comisión Federal de Electricidad, to replace fuel oil-based power plants with natural gas-fueled power plants, which are more economical and produce fewer GHG emissions. The estimated total cost of the project is approximately $430 million to $480 million. We contributed approximately $30 million to Roadrunner in 2015, and we expect to contribute approximately $50 million to Roadrunner during 2016.

Roadrunner has all permits needed to complete construction on Phase I and all permits needed to begin construction on Phase II. Construction on both Phase I and Phase II is ongoing and we expect Phase I to be completed in the first quarter 2016.

Roadrunner entered into a $230 million senior secured credit facility for the construction and operation of the pipeline. The senior secured credit facility expires seven years after the Roadrunner in-service date of Phase II, which is expected to be completed in the first quarter 2017. In addition, Roadrunner executed interest-rate swaps to hedge the variability of its interest payments during the term of the credit facility. Roadrunner's credit facility is nonrecourse to us, and we do not guarantee Roadrunner's debts or obligations under the credit facility.

See additional discussion in the "Financial Results and Operating Information" section in our Natural Gas Pipelines segment.

Impairment Charges - In the fourth quarter 2015, we recorded $264.3 million of noncash impairment charges, primarily related to our long-lived assets and equity investments in the dry natural gas area of the Powder River Basin.

Cash Distributions - During 2015, we paid cash distributions totaling $3.16 per unit, an increase of approximately 5 percent over the $3.01 per unit paid during 2014. In January 2016, our general partner declared a cash distribution of $0.79 per unit ($3.16 per unit on an annualized basis) for the fourth quarter 2015.

Debt Issuances - In January 2016, we entered into the $1.0 billion senior unsecured Term Loan Agreement with a syndicate of banks that matures in January 2019. Proceeds from the Term Loan Agreement effectively refinance our 2016 debt maturities.

In March 2015, we completed an underwritten public offering of $800 million of senior notes, generating net proceeds of approximately $792.3 million. We used the proceeds to repay amounts outstanding under our commercial paper program and for general partnership purposes.

Equity Issuances - In August 2015, we completed a private placement of 21.5 million common units at a price of $30.17 per unit with ONEOK. Additionally, we completed a concurrent sale of approximately 3.3 million common units at a price of $30.17 per unit to funds managed by Kayne Anderson Capital Advisors in a registered direct offering, which were issued through our existing "at-the-market" equity program. The combined offerings generated net cash proceeds of approximately $749 million. In conjunction with these issuances, ONEOK Partners GP contributed approximately $15.3 million in order to maintain its 2 percent general partner interest in us. We used the proceeds for general partnership purposes, including capital expenditures and repayment of commercial paper borrowings.

During 2015, we sold 10.5 million common units through our "at-the-market" equity program, including the units sold to funds managed by Kayne Anderson Capital Advisors in the offering discussed above. The net proceeds, including ONEOK Partners GP's contribution to maintain its 2 percent general partner interest in us, were approximately $381.6 million, which were used for general partnership purposes, including repayment of commercial paper borrowings.

As a result of these transactions, ONEOK's aggregate ownership interest in us increased to 41.2 percent at December 31, 2015, compared with 37.8 percent at December 31, 2014.

FINANCIAL RESULTS AND OPERATING INFORMATION

Consolidated Operations

Selected Financial Results - The following table sets forth certain selected consolidated financial results for the periods indicated:

	Years Ended December 31,			Variances 2015 vs. 2014		Variances 2014 vs. 2013	
Financial Results	**2015**	**2014**	**2013**	**Increase (Decrease)**		**Increase (Decrease)**	
			(*Millions of dollars*)				
Revenues							
Commodity sales	**$ 6,098.3**	$ 10,725.0	$ 10,549.2	**$ (4,626.7)**	**(43)%**	$ 175.8	2 %
Services	**1,662.8**	1,466.7	1,320.1	**196.1**	**13 %**	146.6	11 %
Total revenues	**7,761.1**	12,191.7	11,869.3	**(4,430.6)**	**(36)%**	322.4	3 %
Cost of sales and fuel (exclusive of items shown separately below)	**5,641.1**	10,088.6	10,222.2	**(4,447.5)**	**(44)%**	(133.6)	(1)%
Operating costs	**692.1**	669.7	521.6	**22.4**	**3 %**	148.1	28 %
Depreciation and amortization	**352.2**	291.2	236.7	**61.0**	**21 %**	54.5	23 %
Impairment of long-lived assets	**83.7**	—	—	**83.7**	*****	—	— %
Gain (loss) on sale of assets	**6.1**	6.6	11.9	**(0.5)**	**(8)%**	(5.3)	(45)%
Operating income	**$ 998.1**	$ 1,148.8	$ 900.7	**$ (150.7)**	**(13)%**	$ 248.1	28 %
Equity in net earnings from investments	**$ 125.3**	$ 117.4	$ 110.5	**$ 7.9**	**7 %**	$ 6.9	6 %
Impairment of equity investments	**$ (180.6)**	$ (76.4)	$ —	**$ 104.2**	*****	$ 76.4	*
Interest expense	**$ (338.9)**	$ (281.9)	$ (236.7)	**$ 57.0**	**20 %**	$ 45.2	19 %
Capital expenditures	**$ 1,186.1**	$ 1,746.0	$ 1,939.3	**$ (559.9)**	**(32)%**	$ (193.3)	(10)%
Cash paid for acquisitions, net of cash received	**$ —**	$ 814.9	$ 394.9	**$ (814.9)**	(100)%	$ 420.0	*

* Percentage change is greater than 100 percent or is not meaningful.

Due to the nature of our contracts, changes in commodity prices and volumes affect both commodity sales and cost of sales and fuel in our Consolidated Statements of Income and therefore the impact is largely offset between the two line items. As a result, we consider operating income provided by revenues less cost of sales and fuel meaningful and necessary to understand our results of operations.

2015 vs. 2014 - Services revenues increased for 2015, compared with 2014, due primarily to higher natural gas and NGL volumes from our recently completed capital projects and acquisitions, in our Natural Gas Gathering and Processing and Natural Gas Liquids segments and higher fees resulting from contract restructuring in our Natural Gas Gathering and Processing segment.

Commodity sales revenues and costs of sales and fuel decreased for 2015, compared with 2014, due to the sharp decline in commodity prices that began in the fourth quarter 2014 and continued throughout 2015 and higher propane and natural gas prices, as well as wider NGL location and product price differentials experienced in the first quarter 2014 as a result of unusually high weather-related seasonal demand. The impact from the price decrease was offset partially by higher gathered and processed volumes in our Natural Gas Gathering and Processing segment and higher NGL volumes transported on gathering lines and fractionated in our Natural Gas Liquids segment in 2015, compared with 2014.

Operating costs and depreciation and amortization expense increased for 2015, compared with 2014, due primarily to the growth of our operations related to the completed capital projects, including acquisitions, in our Natural Gas Gathering and Processing and Natural Gas Liquids segments. This increase was offset partially by decreased operating costs due to lower rates charged by service providers.

We recorded $264.3 million and $76.4 million of noncash impairment charges, primarily related to our long-lived assets and equity investments in the dry natural gas area of the Powder River Basin in 2015 and 2014, respectively.

Equity in net earnings from investments increased for 2015, compared with 2014, due primarily to higher volumes in 2015 delivered to Overland Pass Pipeline from our Bakken NGL Pipeline in our Natural Gas Liquids segment.

Interest expense increased for 2015, compared with 2014, primarily as a result of higher interest costs incurred associated with our issuance of $800 million of senior notes in March 2015, higher interest rates on short-term borrowings and lower capitalized interest due to capital-growth projects completed and placed in service in 2014.

Capital expenditures decreased for 2015, compared with 2014, due to the completion of several large capital-growth projects in 2014, suspension of several projects and the timing of expenditures in 2015 for our capital-growth projects. Cash paid for acquisitions in 2014 relates primarily to the West Texas LPG acquisition for approximately $800 million.

Additional information regarding our financial results and operating information is provided in the following discussion for each of our segments.

2014 vs. 2013 - Revenues less cost of sales and fuel for 2014, compared with 2013, increased due primarily to higher volumes across our systems. Our new natural gas processing plants in the Williston Basin and Mid-Continent region resulted in increased natural gas volumes gathered, processed and sold in our Natural Gas Gathering and Processing segment and, combined with third-party plant connections, increased NGL volumes transported in our Natural Gas Liquids segment’s exchange-services business. Our optimization, marketing, isomerization and differentials-based businesses benefited from wider realized NGL product price differentials in 2014, compared with 2013, primarily related to increased weather-related seasonal demand for propane during the first quarter 2014 and wider realized NGL product price differentials between normal butane and iso-butane. Our Natural Gas Pipelines segment also experienced higher transportation revenues, primarily from increased rates and higher contracted capacity and higher storage revenues from park-and-loan activity. These increases were offset partially by the impact of ethane rejection in our Natural Gas Liquids segment and lower contracted storage capacity in our Natural Gas Pipelines segment.

Operating costs and depreciation and amortization expense increased for 2014, compared with 2013, due primarily to the growth of our operations related to the completed capital projects in our Natural Gas Gathering and Processing and Natural Gas Liquids segments.

In 2014, we recorded $76.4 million of noncash impairment charges related to our equity investment in Bighorn Gas Gathering in our Natural Gas Gathering and Processing segment.

Equity in net earnings from investments increased for 2014, compared with 2013, due primarily to higher volumes in 2014 delivered to Overland Pass Pipeline from our Bakken NGL Pipeline in our Natural Gas Liquids segment.

Interest expense increased for 2014, compared with 2013, primarily as a result of higher interest costs incurred associated with a full year of interest costs on our issuance of $1.25 billion of senior notes in September 2013.

Capital expenditures decreased for 2014, compared with 2013, due primarily to the timing of expenditures related to growth projects in our Natural Gas Gathering and Processing and Natural Gas Liquids segments. In 2014, we also completed the West Texas LPG acquisition for approximately $800 million, compared with our 2013 Sage Creek and Maysville acquisitions totaling approximately $395 million.

Additional information regarding our financial results and operating information is provided in the following discussion for each of our segments.

Natural Gas Gathering and Processing

Growth Projects - Our Natural Gas Gathering and Processing segment is investing in growth projects in NGL-rich areas in the Williston Basin, Stack, SCOOP, Cana-Woodford Shale, Woodford Shale, Springer Shale and the Powder River Basin areas that we expect will enable us to meet the needs of crude oil and natural gas producers in those areas. Nearly all of the new natural gas production is from horizontally drilled wells in nonconventional resource areas. These wells tend to produce volumes at higher initial production rates resulting generally in higher initial decline rates than conventional vertical wells; however, the decline rates flatten out over time. These wells are expected to have long productive lives.

In 2014 and 2015, we completed the following projects:

Completed Projects	Location	Capacity	Approximate Costs (a)	Completion Date
			(*In millions*)	
Rocky Mountain Region				
Garden Creek II processing plant and infrastructure	Williston Basin	100 MMcf/d	$310	August 2014
Garden Creek III processing plant and infrastructure	Williston Basin	100 MMcf/d	$310	October 2014
Lonesome Creek processing plant and infrastructure	Williston Basin	200 MMcf/d	$580 - $620	November 2015
Sage Creek infrastructure	Powder River Basin	Various	$35	December 2015
Natural gas compression	Williston Basin	100 MMcf/d	$70 - $80	December 2015
Mid-Continent Region				
Canadian Valley processing plant and infrastructure	Cana-Woodford Shale	200 MMcf/d	$255	March 2014

(a) Excludes AFUDC.

We have the following natural gas processing plants and related infrastructure in various stages of construction:

Projects in Progress	Location	Capacity	Approximate Costs (a)	Expected Completion Date
			(*In millions*)	
Rocky Mountain Region				
Stateline de-ethanizers	Williston Basin	26 MBbl/d	$60 - $80	Third quarter 2016
Bear Creek processing plant and infrastructure	Williston Basin	80 MMcf/d	$230 - $330	Third quarter 2016
Bronco processing plant and infrastructure	Powder River Basin	50 MMcf/d	$130 - $200	Suspended
Demicks Lake processing plant and infrastructure	Williston Basin	200 MMcf/d	$475 - $670	Suspended
Mid-Continent Region				
Knox processing plant and infrastructure	SCOOP	200 MMcf/d	$240 - $470	Suspended
Total			$1,135 - $1,750	

(a) Excludes AFUDC.

As a result of reductions in crude oil and natural gas drilling by producers due to the decline in crude oil, natural gas and NGL prices and our expectation of slower supply growth or declines, we suspended capital expenditures for certain natural gas processing plants and field infrastructure. We could resume our suspended capital-growth projects when market conditions improve and our customers' needs change. If the current commodity price environment persists for a prolonged period, it may further impact the timing or demand for these projects and additional infrastructure projects or growth opportunities in the future.

For a discussion of our capital expenditure financing, see "Capital Expenditures" in the "Liquidity and Capital Resources" section.

Selected Financial Results - Our Natural Gas Gathering and Processing segment's financial results for the year ended December 31, 2015, reflect the benefits from the completed projects in the table above.

The following table sets forth certain selected financial results for our Natural Gas Gathering and Processing segment for the periods indicated:

	Years Ended December 31,			Variances 2015 vs. 2014		Variances 2014 vs. 2013	
Financial Results	**2015**	**2014**	**2013**	**Increase (Decrease)**		**Increase (Decrease)**	
				(Millions of dollars)			
NGL sales	**$ 554.3**	$ 1,434.4	$ 1,095.5	**$ (880.1)**	**(61)%**	$ 338.9	31 %
Condensate sales	**55.1**	110.8	113.2	**(55.7)**	**(50)%**	(2.4)	(2)%
Residue natural gas sales	**839.5**	1,140.5	620.5	**(301.0)**	**(26)%**	520.0	84 %
Gathering, compression, dehydration and processing fees and other revenue	**388.2**	281.9	222.3	**106.3**	**38 %**	59.6	27 %
Cost of sales and fuel (exclusive of items shown separately below)	**1,265.6**	2,305.7	1,550.9	**(1,040.1)**	**(45)%**	754.8	49 %
Operating costs	**272.4**	257.7	193.3	**14.7**	**6 %**	64.4	33 %
Depreciation and amortization	**150.0**	123.8	103.9	**26.2**	**21 %**	19.9	19 %
Impairment of long-lived assets	**73.7**	—	—	**73.7**	*****	—	— %
Gain (loss) on sale of assets	**2.8**	0.2	0.4	**2.6**	*****	(0.2)	(50)%
Operating income	**$ 78.2**	$ 280.6	$ 203.8	**$ (202.4)**	**(72)%**	$ 76.8	38 %
Equity in net earnings from investments	**$ 17.9**	$ 20.3	$ 23.5	**$ (2.4)**	**(12)%**	$ (3.2)	(14)%
Impairment of equity investments	**$ (180.6)**	$ (76.4)	$ —	**$ 104.2**	*****	$ 76.4	*
Capital expenditures	**$ 887.9**	$ 898.9	$ 774.4	**$ (11.0)**	**(1)%**	$ 124.5	16 %
Cash paid for acquisitions	**$ —**	$ —	$ 241.9	**$ —**	**— %**	$ (241.9)	(100)%

* Percentage change is greater than 100 percent or is not meaningful.

Commodity prices declined sharply in the fourth quarter 2014 and continued to decline throughout 2015. We expect lower commodity prices to continue throughout 2016. Therefore, we also expect crude oil, natural gas and NGL supply growth to continue to slow. As crude oil and natural gas exploration and production capital investment has decreased due to market conditions, crude oil and natural gas producers are focusing their drilling activities in the most productive areas that are most economical to develop and have higher production volumes, which offsets partially the reduction in drilling activity. The lower commodity price environment had a significant impact on our Natural Gas Gathering and Processing segment's financial results in 2015, compared with 2014, but was mitigated partially by restructured contracts primarily in the fourth quarter 2015.

<u>2015 vs. 2014</u> - Operating income provided by revenues less cost of sales and fuel decreased primarily as a result of the following:

- a decrease of $209.7 million due primarily to lower net realized NGL, natural gas and condensate prices; and
- a decrease of $10.4 million due primarily to decreased ethane rejection to maintain downstream NGL product specifications; offset partially by
- an increase of $91.6 million due primarily to restructured contracts resulting in higher average fee rates and a lower percentage of proceeds retained from the sale of commodities under our POP with fee contracts; and
- an increase of $38.1 million due primarily to natural gas volume growth in the Williston Basin, offset partially by unplanned operational outages in the Williston Basin and decreased natural gas volumes in the Cana-Woodford Shale.

Operating costs increased due primarily to the growth of our operations and reflect the following:

- an increase of $13.8 million in higher outside service expenses due primarily to the completion of our growth projects;
- an increase of $10.5 million in employee-related costs due to higher labor and employee benefit costs resulting from the completion of our growth projects; and
- an increase of $3.1 million due to higher ad valorem taxes resulting from the completion of our growth projects; offset partially by
- a decrease of $12.7 million in materials and supplies due primarily to lower chemical costs.

Depreciation and amortization expense increased due to the completion of growth projects.

We recorded $254.3 million and $76.4 million of noncash impairment charges primarily related to our long-lived assets and equity investments in the dry natural gas area of the Powder River Basin in 2015 and 2014, respectively. See additional discussion in “Impairment Charges” below.

Capital expenditures decreased due primarily to the timing of our growth projects discussed above.

See “Capital Expenditures” in “Liquidity and Capital Resources” for additional detail of our projected capital expenditures.

2014 vs. 2013 - Operating income provided by revenues less cost of sales and fuel increased primarily as a result of the following:

- an increase of $147.6 million due primarily to natural gas volume growth in the Williston Basin and Cana-Woodford Shale and increased ownership of the Maysville, Oklahoma, natural gas processing plant resulting in higher natural gas volumes gathered, compressed, processed, transported and sold, higher NGL volumes sold and higher fees, offset partially by wellhead freeze-offs due to severely cold weather in the first quarter 2014;
- an increase of $11.3 million due primarily to higher net realized natural gas and NGL prices; and
- an increase of $8.8 million due primarily to higher average fee rates and a lower percentage of proceeds retained from the sale of commodities under our POP with fee contracts; offset partially by
- a decrease of $6.4 million due to a condensate contract settlement in 2013.

Operating costs increased due primarily to the growth of our operations and reflect the following:

- an increase of $46.3 million in higher materials and supplies, and outside service expenses; and
- an increase of $21.2 million in employee-related costs due to higher labor and employee benefit costs; offset partially by
- a decrease of $3.2 million due to lower ad valorem tax expense resulting from capitalized taxes related to construction projects.

Depreciation and amortization expense increased due to the completion of growth projects and acquisitions.

In 2014, we recorded $76.4 million of noncash impairment charges related to our equity investment in Bighorn Gas Gathering.

Capital expenditures increased due primarily to the timing of our growth projects discussed above.

Selected Operating Information - The following tables set forth selected operating information for our Natural Gas Gathering and Processing segment for the periods indicated:

	Years Ended December 31,		
Operating Information (a)	**2015**	**2014**	**2013**
Natural gas gathered (*BBtu/d*)	**1,932**	1,733	1,347
Natural gas processed (*BBtu/d*) (b)	**1,687**	1,534	1,094
NGL sales (*MBbl/d*)	**129**	104	79
Residue natural gas sales (*BBtu/d*)	**853**	714	497
Realized composite NGL net sales price (*$/gallon*) (c) (d)	**$ 0.34**	$ 0.93	$ 0.87
Realized condensate net sales price (*$/Bbl*) (c) (e)	**$ 37.81**	$ 76.43	$ 86.00
Realized residue natural gas net sales price (*$/MMBtu*) (c) (e)	**$ 3.64**	$ 3.92	$ 3.53
Average fee rate (*$MMBtu*)	**$ 0.44**	$ 0.36	$ 0.34

(a) - Includes volumes for consolidated entities only.
(b) - Includes volumes at company-owned and third-party facilities.
(c) - Includes the impact of hedging activities on our equity volumes.
(d) - Net of transportation and fractionation costs.
(e) - Net of transportation costs.

Natural gas gathered and processed, NGL sales and residue natural gas sales increased in 2015, compared with 2014, due to the completion of growth projects in the Williston Basin, offset partially by unplanned outages in the Williston Basin during the third quarter and natural gas volume declines in the Cana-Woodford Shale. In 2016, we expect our average natural gas gathered volumes to increase in the Cana-Woodford Shale as a result of wells completed in late 2015. Natural gas gathered and processed, NGL sales and residue natural gas sales increased in 2014, compared with 2013, due to the completion of growth projects in the Williston Basin and the Mid-Continent areas, offset partially by natural declines in the Powder River Basin.

The quantity and composition of NGLs and natural gas have varied as new plants were placed in service and to ensure natural gas and natural gas liquids pipeline specifications were met. Beginning in June 2015, we reduced the level of ethane rejection in the Rocky Mountain region to address downstream NGL product specifications. In 2016, we expect additional volumes from our Lonesome Creek and Bear Creek processing plants in the Williston Basin to further reduce the level of ethane rejection. We expect the decreased level of ethane rejection to continue throughout 2016.

	Years Ended December 31,		
Equity Volume Information (a)	**2015**	**2014**	**2013**
NGL sales (*MBbl/d*)	**20.9**	16.5	14.4
Condensate sales (*MBbl/d*)	**2.8**	3.1	2.4
Residue natural gas sales (*BBtu/d*)	**136.2**	118.2	71.7

(a) - Includes volumes for consolidated entities only.

Commodity Price Risk - Our Natural Gas Gathering and Processing segment is exposed to commodity price risk as a result of receiving commodities as a portion of our compensation for our services. See discussion regarding our commodity price risk under "Commodity Price Risk" in Item 7A, Quantitative and Qualitative Disclosures about Market Risk.

Impairment Charges - Crude oil and natural gas producers have primarily focused their development efforts on crude oil and NGL-rich supply basins rather than in areas with dry natural gas production, such as the coal-bed methane production areas in the Powder River Basin. The reduced development activities and production declines in the dry natural gas area of the Powder River Basin have resulted in lower natural gas volumes available to be gathered. Due to the continued and greater than expected decline in volumes gathered in the dry natural gas area of the Powder River Basin, we evaluated our long-lived assets and equity investments in this area and determined that we will cease operations of our wholly owned coal-bed methane natural gas gathering system in 2016. This resulted in a $63.5 million noncash impairment charge to our long-lived assets in the fourth quarter 2015. Bighorn Gas Gathering, in which we own a 49 percent equity interest, and Fort Union Gas Gathering, in which we own a 37 percent equity interest, are both partially supplied with volumes from our wholly owned coal-bed methane natural gas gathering system. We also own a 35 percent equity interest in Lost Creek Gathering Company, which also is located in a dry natural gas area. We reviewed our Bighorn Gas Gathering, Fort Union Gas Gathering and Lost Creek Gathering Company equity investments and recorded noncash impairment charges of $180.6 million in the fourth quarter 2015. The remaining net book value of our equity investments in this dry natural gas area is $35.0 million.

In the fourth quarter 2015, we also recorded a noncash impairment charge of approximately $10.2 million related to a previously idled asset, as our expectation for future use of the asset changed.

During 2014, Bighorn Gas Gathering recorded an impairment of its underlying assets when the operator determined that the volume decline would be sustained for the foreseeable future. As a result, we reviewed our equity investment in Bighorn Gas Gathering for impairment and recorded noncash impairment charges of $76.4 million in 2014 related to Bighorn Gas Gathering.

Natural Gas Liquids

Growth Projects - Our growth strategy in our Natural Gas Liquids segment is focused around the crude oil and NGL-rich natural gas drilling activity in shale and other nonconventional resource areas from the Rocky Mountain region through the Mid-Continent region into Texas and New Mexico. Crude oil, natural gas and NGL production from this activity; higher petrochemical industry demand for NGL products; and increased exports have resulted in our making additional capital investments to expand our infrastructure to bring these commodities from supply basins to market. Expansion of the petrochemical industry in the United States is expected to increase ethane demand significantly beginning in 2017, and international demand for NGLs, particularly propane, also is increasing and is expected to continue to do so in the future.

Our Natural Gas Liquids segment invests in NGL-related projects to accommodate the transportation, fractionation and storage of NGL supply from shale and other resource development areas across our asset base and alleviate expected infrastructure constraints between the Mid-Continent and Gulf Coast market centers to meet increasing petrochemical industry and NGL export demand in the Gulf Coast.

We completed the following growth projects in this segment in 2014 and 2015:

Completed Projects	Location	Capacity	Approximate Costs (a)	Completion Date
			(*In millions*)	
Ethane/Propane Splitter	Gulf Coast	40 MBbl/d	$46	March 2014
Sterling III Pipeline and reconfigure Sterling I and II	Mid-Continent Region	193 MBbl/d	$808	March 2014
Bakken NGL Pipeline expansion - Phase I	Rocky Mountain Region	75 MBbl/d	$90	September 2014
Niobrara NGL Lateral	Powder River Basin	90 miles	$65	September 2014
West Texas LPG (b)	Permian Basin	2,600 miles	$800	November 2014
MB-3 Fractionator	Gulf Coast	75 MBbl/d	$530	December 2014
NGL Pipeline and Hutchinson Fractionator infrastructure	Mid-Continent Region	95 miles	$120	April 2015

(a) Excludes AFUDC.
(b) Acquisition.

We have the following projects in various stages of construction:

Projects in Progress	Location	Capacity	Approximate Costs (a)	Expected Completion Date
			(*In millions*)	
Bear Creek NGL infrastructure	Williston Basin	40 miles	$35-$45	Third quarter 2016
Bakken NGL Pipeline expansion - Phase II	Rocky Mountain Region	25 MBbl/d	$100	Third quarter 2018
Bronco NGL infrastructure	Powder River Basin	65 miles	$45-$60	Suspended
Demicks Lake NGL infrastructure	Williston Basin	12 miles	$10-$15	Suspended
Total			$190-$220	

(a) Excludes AFUDC.

As a result of reductions in crude oil and natural gas drilling activities and our expectation of continued slower supply growth or declines due to the lower crude oil, natural gas and NGL prices, we have suspended capital expenditures for certain natural gas liquids infrastructure projects related to planned natural gas processing plants. We could resume our suspended capital-growth projects when market conditions improve and our customers' needs change. If the current commodity price environment persists for a prolonged period, it may further impact the timing or demand for these projects and additional infrastructure projects or growth opportunities in the future.

For a discussion of our capital expenditure financing, see "Capital Expenditures" in the "Liquidity and Capital Resources" section.

Selected Financial Results - Our Natural Gas Liquids segment's financial results for the year ended December 31, 2015, reflect the benefits from the completed growth projects in the table above.

The following tables set forth certain selected financial results and operating information for our Natural Gas Liquids segment for the periods indicated:

	Years Ended December 31,			Variances 2015 vs. 2014		Variances 2014 vs. 2013	
Financial Results	**2015**	**2014**	**2013**	**Increase (Decrease)**		**Increase (Decrease)**	
			(Millions of dollars)				
NGL and condensate sales	**$ 5,200.8**	$ 9,462.4	$ 9,857.7	**$ (4,261.6)**	**(45)%**	$ (395.3)	(4)%
Exchange service and storage revenues	**1,199.7**	988.8	839.3	**210.9**	**21 %**	149.5	18 %
Transportation revenues	**179.2**	94.2	81.0	**85.0**	**90 %**	13.2	16 %
Cost of sales and fuel (exclusive of items shown separately below)	**5,328.3**	9,435.3	9,908.1	**(4,107.0)**	**(44)%**	(472.8)	(5)%
Operating costs	**314.5**	296.4	236.6	**18.1**	**6 %**	59.8	25 %
Depreciation and amortization	**158.7**	124.1	89.2	**34.6**	**28 %**	34.9	39 %
Impairment of long-lived assets	**10.0**	—	—	**10.0**	*****	—	— %
Gain (loss) on sale of assets	**(0.9)**	(0.6)	0.8	**(0.3)**	**50 %**	(1.4)	*
Operating income	**$ 767.3**	$ 689.0	$ 544.9	**$ 78.3**	**11 %**	$ 144.1	26 %
Equity in net earnings from investments	**$ 38.7**	$ 27.3	$ 22.0	**$ 11.4**	**42 %**	$ 5.3	24 %
Capital expenditures	**$ 226.1**	$ 798.0	$ 1,128.3	**$ (571.9)**	**(72)%**	$ (330.3)	(29)%
Cash paid for acquisitions, net of cash received	**$ —**	$ 800.9	$ 153.0	**$ (800.9)**	**(100)%**	$ 647.9	*

* Percentage change is greater than 100 percent or is not meaningful.

Crude prices declined sharply beginning in the fourth quarter 2014 and remained relatively low throughout 2015, which impacted NGL prices as NGL prices generally are linked to crude oil prices. These lower prices decreased both our NGL and condensate sales revenue and cost of sales and fuel in our Consolidated Statements of Income. Therefore, the impact is largely offset between revenues and cost of sales and fuel.

In the first quarter 2014, we experienced increased propane demand and prices, which impacted our results of operations in 2014, due to colder than normal weather. The price of propane in the Mid-Continent market and the wider location price differentials between the Mid-Continent and Gulf Coast market centers peaked in late January 2014 and returned to then historical levels by the end of February 2014 as supply and demand balanced.

<u>2015 vs. 2014</u> - Operating income provided by revenues less cost of sales and fuel increased primarily as a result of the following:

- an increase of $191.0 million in our fee-based exchange-services, which resulted from increased volumes from new plants connected in the Williston Basin and Mid-Continent region and higher revenues from customers with minimum volume obligations;
- an increase of $81.8 million in our transportation business due primarily to the acquisition of the West Texas LPG system in the Permian Basin, which was acquired in November 2014; and
- an increase of $23.8 million resulting from decreased ethane rejection in the Williston Basin resulting from downstream NGL product specification issues, offset partially by higher ethane rejection in the Mid-Continent region; offset partially by
- a decrease of $118.4 million in our optimization, marketing and differentials-based activities, which resulted from a $66.3 million decrease due primarily to narrower NGL product price differentials, a $27.7 million decrease due primarily to narrower NGL location price differentials and a $24.4 million decrease in our marketing business. A portion of this decrease relates to the increased demand for propane experienced during the first quarter 2014;
- a decrease of $29.9 million related to lower isomerization volumes resulting from narrower NGL price differential between normal butane and iso-butane; and
- a decrease of $6.9 million due to the impact of operational losses in 2015 and operational measurement gains in 2014.

Operating costs increased primarily as a result of the completion of our growth projects and acquisition and include the following:

- an increase of $29.2 million due to the West Texas LPG acquisition; and

- an increase of $6.5 million due to higher ad valorem taxes; offset partially by
- a decrease of $17.6 million due to reduced operating costs resulting from lower rates charged by service providers, primarily from $6.6 million lower outside services, $5.0 million lower supplies and expenses and $3.2 million lower chemicals and materials.

Depreciation and amortization expense increased due primarily to our completed capital projects and acquisition.

In the fourth quarter 2015, we recorded a noncash impairment charge of approximately $10.0 million related to a previously idled asset, as our expectation for future use of the asset changed.

Equity in net earnings from investments increased in 2015, compared with 2014, due primarily to higher volumes delivered to Overland Pass Pipeline from our Bakken NGL Pipeline.

Capital expenditures decreased due primarily to the completion of several growth projects in 2014.

2014 vs. 2013 - We experienced significantly higher prices in the first quarter 2014 due to severely cold weather, compared with 2013. In response to increased heating demand, propane prices increased significantly at the Mid-Continent market center at Conway, Kansas, compared with the Gulf Coast market center at Mont Belvieu, Texas, in the first quarter 2014. The price of propane in the Mid-Continent market and the wider location price differentials between the Mid-Continent and Gulf Coast market centers peaked in late January 2014 and returned to historical levels by the end of February 2014 as supply and demand balanced.

Operating income provided by revenues less cost of sales and fuel increased primarily as a result of the following:

- an increase of $157.4 million in our fee-based exchange and transportation services, which resulted from increased volumes from new plants connected in the Williston Basin and Mid-Continent region, and higher fees for exchange-services activities resulting from contract renegotiations, offset partially by lower volumes from the termination of a contract;
- an increase of $79.8 million in our optimization, marketing and differentials-based activities, which resulted from a $31.4 million increase due primarily to wider realized NGL product price differentials; a $25.2 million increase in our marketing business related primarily to increased weather-related seasonal demand for propane during the first quarter 2014, and marketing and truck and rail activities in the second, third and fourth quarters 2014; and a $23.2 million increase due primarily to significantly wider NGL location price differentials, primarily related to increased weather-related seasonal demand for propane during the first quarter 2014, offset partially by lower optimization volumes in the second, third and fourth quarters 2014 when differentials narrowed; and
- an increase of $22.8 million related to higher isomerization volumes resulting from the wider NGL product price differential between normal butane and iso-butane; offset partially by
- a decrease of $18.3 million resulting from the impact of ethane rejection, which resulted in lower NGL volumes; and
- a decrease of $6.0 million due to the impact of lower operational measurement gains.

Operating costs increased primarily as a result of the completion of our growth projects, which include the following:

- an increase of $20.1 million due to higher outside services expenses associated primarily with scheduled maintenance and the growth of operations related to completed capital projects;
- an increase of $15.5 million due to higher ad valorem taxes related to our completed capital projects;
- an increase of $14.9 million due to higher employee-related costs due primarily to higher labor and employee benefit costs; and
- an increase of $3.4 million due to higher chemical, materials and supplies expense.

Depreciation and amortization expense increased due primarily to our completed capital projects.

Equity in net earnings from investments increased in 2014, compared with 2013, due primarily to higher volumes delivered to Overland Pass Pipeline from our Bakken NGL Pipeline that was placed in service in April 2013 and revenues from minimum volume agreements, offset partially by increased ethane rejection and higher operating costs.

Capital expenditures decreased due primarily to timing of expenditures on our growth projects discussed above.

Selected Operating Information - The following tables set forth selected operating information for our Natural Gas Liquids segment for the periods indicated:

Operating Information	Years Ended December 31, 2015	2014	2013
NGL sales (*MBbl/d*)	**660**	615	657
NGLs transported - gathering lines (*MBbl/d*) (a)	**769**	533	547
NGLs fractionated (*MBbl/d*) (b)	**552**	522	535
NGLs transported - distribution lines (*MBbl/d*) (a)	**428**	408	435
Average Conway-to-Mont Belvieu OPIS price differential - ethane in ethane/propane mix (*$/gallon*)	**$ 0.02**	$ 0.05	$ 0.04

(a) - Includes volumes for consolidated entities only.
(b) - Includes volumes at company-owned and third-party facilities.

2015 vs. 2014 - NGLs transported on gathering lines and NGLs fractionated increased due to increased volumes from new plant connections in the Williston Basin and Mid-Continent region and decreased ethane rejection in the Rocky Mountain region, offset partially by increased ethane rejection in the Mid-Continent region. The decreased ethane rejection in the Rocky Mountain region began in June 2015 due to downstream NGL product specifications and increased gathered volumes by approximately 20 MBbl/d in the second half of 2015. We expect this decreased level of rejection to continue throughout 2016. NGLs transported on gathering lines also increased significantly due to volumes from the Permian Basin transported on the West Texas LPG system, which was acquired in November 2014.

NGLs transported on distribution lines increased due primarily to higher gathered and fractionated volumes as discussed above and due to increased volumes transported for our optimization business.

2014 vs. 2013 - NGLs transported on gathering lines and NGLs fractionated decreased due primarily to the termination of a low fee-rate contract and increased ethane rejection in the Mid-Continent and Rocky Mountain regions, offset partially by volumes from new plants connected in the Williston Basin and Mid-Continent region and from the West Texas LPG system acquired in November 2014.

NGLs transported on distribution lines decreased due primarily to lower volumes transported for our optimization business due to narrower location price differentials during the second, third and fourth quarters 2014 between the Conway and Mont Belvieu market centers and increased ethane rejection, offset partially by an increase in exchange volumes delivered to Mont Belvieu due to the completed Sterling III Pipeline, which was placed in service in March 2014; and higher NGL volumes, primarily propane, during the first quarter 2014, transported to the Mid-Continent region due to increased demand.

Natural Gas Pipelines

Growth Projects - The following projects are in various stages of construction. Roadrunner is a 50 percent-owned joint venture equity-method investment project. WesTex is a wholly owned project.

Projects in Progress	Location	Capacity	Approximate Costs (a)	Expected Completion Date
			(*In millions*)	
WesTex Pipeline Expansion	Permian Basin	260 MMcf/d	$70-$100	First quarter 2017
Roadrunner Gas Transmission Pipeline - Equity-Method Investment				
Phase I (b)	Permian Basin	170 MMcf/d	$190-$210	First quarter 2016
Phase II (b)	Permian Basin	400 MMcf/d	$210-$230	First quarter 2017
Phase III (b)	Permian Basin	70 MMcf/d	$30-$40	2019
Roadrunner Gas Transmission Pipeline Total			$430-$480	

(a) - Excludes AFUDC.
(b) - 50-50 joint venture equity-method investment. Approximate costs represents total project costs, which are expected to be financed with approximately 50 percent equity contributions and 50 percent debt issued by Roadrunner. We expect to make equity contributions for approximately 25 percent of the total project costs.

Roadrunner - In March 2015, we entered into a 50-50 joint venture with a subsidiary of Fermaca, a Mexico City-based natural gas infrastructure company, to construct a pipeline to transport natural gas from the Permian Basin in West Texas to the

Mexican border near El Paso, Texas. The Roadrunner pipeline will connect with our existing natural gas pipeline and storage infrastructure in Texas and, together with our WesTex intrastate natural gas transmission pipeline expansion project, is expected to create a platform for future opportunities to deliver natural gas supply to Mexico. These integrated assets also are expected to provide markets in Mexico access to upstream supply basins in West Texas and the Mid-Continent region, which adds location and price diversity to their supply mix and supports the plan of Mexico's national electric utility, Comisión Federal de Electricidad, to replace oil-fueled power plants with natural gas-fueled power plants, which are more economical and produce fewer GHG emissions.

The Roadrunner pipeline was fully subscribed for its initial design through an open season process held in December 2014. Precedent agreements representing the initial design capacity have been executed with the Comisión Federal de Electricidad and a Fermaca subsidiary. All transportation agreements are firm demand charge and have a term of 25 years. Additional capacity could become available through future expansions depending on market demand.

We are managing the construction of the project and will be the operator of the pipeline upon its completion. The estimated total cost of the project is approximately $430 million to $480 million. We contributed approximately $30 million to Roadrunner for the year ended December 31, 2015, and we expect to contribute approximately $50 million to Roadrunner during 2016. Roadrunner entered into a $230 million senior secured credit facility for the construction and operation of the pipeline. The senior secured credit facility expires seven years after the Roadrunner Phase II in-service date, which is expected to be completed in the first quarter 2017. In addition, Roadrunner executed interest-rate swaps to hedge the variability of its interest payments during the term of the credit facility. Roadrunner's credit facility is nonrecourse to us, and we do not guarantee Roadrunner's debts or obligations under the credit facility.

Roadrunner has all permits needed to complete construction on Phase I and all permits needed to begin construction on Phase II. Construction on both Phase I and Phase II is ongoing and we expect Phase I to be completed in the first quarter 2016.

WesTex Pipeline Expansion - In July 2015, we announced that we plan to expand the capacity of the WesTex intrastate natural gas pipeline by constructing two new compressor stations and upgrading or expanding three existing compressor stations. The expansion project is approximately 90 percent subscribed with long-term firm demand charge transportation contracts and will complement the Roadrunner pipeline project. Together, these projects provide markets in Mexico access to upstream supply basins in West Texas and the Mid-Continent region.

Selected Financial Results and Operating Information - The following tables set forth certain selected financial results and operating information for our Natural Gas Pipelines segment for the periods indicated:

	Years Ended December 31,			Variances 2015 vs. 2014		Variances 2014 vs. 2013	
Financial Results	**2015**	**2014**	**2013**	**Increase (Decrease)**		**Increase (Decrease)**	
				(Millions of dollars)			
Transportation revenues	**$ 258.6**	$ 270.5	$ 233.0	**$ (11.9)**	**(4)%**	$ 37.5	16 %
Storage revenues	**57.1**	64.0	70.4	**(6.9)**	**(11)%**	(6.4)	(9)%
Natural gas sales and other revenues	**16.7**	15.9	22.1	**0.8**	**5 %**	(6.2)	(28)%
Cost of sales and fuel (exclusive of items shown separately below)	**34.5**	21.9	39.8	**12.6**	**58 %**	(17.9)	(45)%
Operating costs	**105.7**	111.0	101.2	**(5.3)**	**(5)%**	9.8	10 %
Depreciation and amortization	**43.5**	43.3	43.5	**0.2**	**— %**	(0.2)	— %
Gain (loss) on sale of assets	**4.3**	6.8	10.6	**(2.5)**	**(37)%**	(3.8)	(36)%
Operating income	**$ 153.0**	$ 181.0	$ 151.6	**$ (28.0)**	**(15)%**	$ 29.4	19 %
Equity in net earnings from investments	**$ 68.7**	$ 69.8	$ 65.0	**$ (1.1)**	**(2)%**	$ 4.8	7 %
Capital expenditures	**$ 58.2**	$ 43.0	$ 34.7	**$ 15.2**	**35 %**	$ 8.3	24 %
Cash paid for acquisitions	**$ —**	$ 14.0	$ —	**$ (14.0)**	**(100)%**	$ 14.0	*

* Percentage change is greater than 100 percent or is not meaningful.

2015 vs. 2014 - Operating income provided by revenues less cost of sales and fuel decreased primarily as a result of the following:

- a decrease of $24.3 million from lower short-term natural gas storage services as a result of weather-related seasonal demand associated with severely cold weather in the first quarter 2014;
- a decrease of $10.0 million from lower net retained fuel due to lower natural gas prices and natural gas volumes retained; and

- a decrease of $5.0 million from lower park-and-loan services on our interstate pipelines as a result of weather-related seasonal demand due to severely cold weather in the first quarter 2014; offset partially by
- an increase of $8.6 million due to higher transportation revenues, primarily from increased rates on intrastate pipelines and higher rates on Viking Gas Transmission, offset partially by decreased interruptible transportation revenues from lower natural gas volumes transported.

Operating costs decreased primarily as a result of lower materials and supplies and outside services expenses.

Gain on sale of assets decreased in 2015 primarily as a result of excess pad gas sales of $4.3 million in 2015, compared with $6.8 million in the prior year.

Equity in net earnings from investments decreased $1.1 million due primarily to decreased park-and-loan services on Northern Border Pipeline as a result of weather-related seasonal demand due to severely cold weather in the first quarter 2014, offset partially by an increase in contracted firm transportation.

Capital expenditures increased due primarily to a compressor station expansion project.

2014 vs. 2013 - Operating income provided by revenues less cost of sales and fuel increased primarily as a result of the following:

- an increase of $26.3 million due to higher transportation revenues primarily from increased rates on intrastate pipelines, higher contracted capacity and rates on Midwestern Gas Transmission and increased interruptible transportation revenues from higher natural gas volumes transported;
- an increase of $17.6 million from higher short-term natural gas storage services due to higher park-and-loan activity as a result of weather-related seasonal demand primarily in the first quarter 2014 and greater capacity available for such services;
- an increase of $5.1 million due to increased park-and-loan services on our interstate pipelines as a result of weather-related seasonal demand in the first quarter 2014;
- an increase of $5.0 million from higher net retained fuel due to higher natural gas prices and natural gas volumes retained; and
- an increase of $3.1 million from additional storage services to meet utility customers' peak-day demand; offset partially by
- a decrease of $14.3 million due to lower storage revenues from lower contracted firm capacity.

Operating costs increased primarily as a result of increased employee-related costs due to higher labor and employee benefit costs, as well as higher expenditures for outside services associated with scheduled maintenance and higher materials and supplies expenses.

Gain on sale of assets decreased in 2014 as a result of excess pad gas sales of $6.8 million in 2014, compared with $10.5 million in the prior year.

Equity in net earnings from investments increased $4.8 million due primarily to increased park-and-loan services on Northern Border Pipeline as a result of increased weather-related seasonal demand in the first quarter 2014, offset partially by lower contracted capacity.

	Years Ended December 31,		
Operating Information (a)	**2015**	**2014**	**2013**
Natural gas transportation capacity contracted (*MDth/d*)	**5,840**	5,781	5,524
Transportation capacity subscribed	**92%**	91%	90%
Average natural gas price			
Mid-Continent region (*$/MMBtu*)	**$ 2.42**	$ 4.33	$ 3.61

(a) - Includes volumes for consolidated entities only.

Our natural gas pipelines primarily serve end users, such as natural gas distribution and electric-generation companies, that require natural gas to operate their businesses regardless of location price differentials. The development of shale and other resource areas has continued to increase available natural gas supply resulting in narrower location and seasonal price differentials. As additional supply is developed, we expect crude oil and natural gas producers to demand incremental services in the future to transport their production to market. The abundance of shale gas supply and new regulations on emissions from coal-fired electric-generation plants may also increase the demand for our services from electric-generation companies as they convert to a natural gas fuel source. Conversely, contracted capacity by certain customers that are focused on capturing location or seasonal price differentials may decrease in the future due to narrowing price differentials. Overall, we expect our fee-based earnings in this segment to remain relatively stable with growth in the Permian Basin as we complete construction of our Roadrunner joint venture and our WesTex pipeline expansion.

In August 2014, Viking Gas Transmission filed a "Stipulation and Agreement in Resolutions of All Issues Concerning Adjustment in Rates of Viking Gas Transmission Company" (settlement) with the FERC. The settlement was approved on October 1, 2014, and became final on October 31, 2014. Rates under the settlement became effective January 1, 2015.

Northern Border Pipeline, in which we have a 50 percent ownership interest, has contracted substantially all of its long-haul transportation capacity through the first quarter 2017.

Adjusted EBITDA

Adjusted EBITDA is a non-GAAP measure of the Partnership's financial performance. Adjusted EBITDA is defined as net income adjusted for interest expense, depreciation and amortization, impairment charges, income taxes and allowance for equity funds used during construction and other certain noncash items. We believe this non-GAAP financial measure is useful to investors because it is used by many companies in our industry as a measurement of financial performance and is commonly employed by financial analysts and others to evaluate our financial performance and to compare our financial performance with the performance of other publicly traded partnerships within our industry. Management also uses Adjusted EBITDA to evaluate the performance of the Partnership as a whole. Adjusted EBITDA should not be considered an alternative to net income, earnings per unit or any other measure of financial performance presented in accordance with GAAP. Additionally, this calculation may not be comparable with similarly titled measures of other companies.

A reconciliation of Adjusted EBITDA for the years ended December 31, 2015, 2014 and 2013, to net income, which is the nearest comparable GAAP financial measure, is as follows:

	Years Ended December 31,		
(*Unaudited*)	**2015**	**2014**	**2013**
Reconciliation of Net Income to Adjusted EBITDA	(*Thousands of dollars*)		
Net income	**$ 597,872**	$ 911,335	$ 803,983
Interest expense	**338,911**	281,908	236,714
Depreciation and amortization	**352,196**	291,236	236,743
Impairment charges	**264,256**	76,412	—
Income taxes	**4,144**	12,668	10,858
Allowance for equity funds used during construction and other noncash items	**8,126**	(14,937)	(30,522)
Adjusted EBITDA	**$ 1,565,505**	$ 1,558,622	$ 1,257,776

Adjusted EBITDA for the year ended December 31, 2015, was relatively unchanged, compared with 2014, due primarily to an increase in operating income provided by revenues less cost of sales and fuel and equity in net earnings from investments, excluding the effects of the impairment charges. These increases were offset partially by increased operating costs due primarily to the growth of our operations related to our completed capital projects and acquisitions. See also the discussion in "Financial Results and Operating Information."

CONTINGENCIES

Legal Proceedings - We are a party to various litigation matters and claims that have arisen in the normal course of our operations. While the results of these litigation matters and claims cannot be predicted with certainty, we believe the reasonably possible losses from such matters, individually and in the aggregate, are not material. Additionally, we believe the probable final outcome of such matters will not have a material adverse effect on our consolidated results of operations, financial position or cash flows.

LIQUIDITY AND CAPITAL RESOURCES

General - We rely primarily on operating cash flows, commercial paper, bank credit facilities, debt issuances and the issuance of common units for our liquidity and capital resources requirements. As of December 31, 2015, we had $5.1 million of cash on hand and available capacity under our Partnership Credit Agreement of $1.8 billion. In addition, in January 2016, we entered into the $1.0 billion senior unsecured Term Loan Agreement with a syndicate of banks that matures in January 2019.

We fund our operating expenses, debt service and cash distributions to our limited partners and general partner primarily with operating cash flows. To the extent operating cash flows are not sufficient to fund our cash distributions, we may utilize short- and long-term debt and issuances of equity, as necessary. Capital expenditures are funded by operating cash flows, short- and long-term debt and issuances of equity. Our ability to continue to access capital markets for debt and equity financing under reasonable terms depends on our financial condition, credit ratings and market conditions. The significant decline in commodity prices has increased the cost of debt and equity financing for us and others in our industry. While lower commodity prices and industry uncertainty may result in increased financing costs, we expect to utilize our commercial paper program, Partnership Credit Agreement, Term Loan Agreement and cash from operations to fund our announced growth capital expenditures, refinance our senior notes maturities and meet our working capital needs through 2016 and well into 2017. However, we may access the capital markets to issue debt or equity securities prior to that time as we consider prudent to provide liquidity for new capital projects, to maintain investment-grade credit ratings or other partnership purposes.

We have no guarantees of debt or other similar commitments to unaffiliated parties.

Capital Structure - The following table sets forth our capitalization structure at the dates indicated:

	December 31,	
	2015	**2014**
Long-term debt	**51%**	50%
Equity	**49%**	50%
Debt (including notes payable)	**53%**	54%
Equity	**47%**	46%

Cash Management - We use a centralized cash management program that concentrates the cash assets of our operating subsidiaries in joint accounts for the purposes of providing financial flexibility and lowering the cost of borrowing, transaction costs and bank fees. Our centralized cash management program provides that funds in excess of the daily needs of our operating subsidiaries are concentrated, consolidated or otherwise made available for use by other entities within our consolidated group. Our operating subsidiaries participate in this program to the extent they are permitted pursuant to FERC regulations or our operating agreement. Under the cash management program, depending on whether a participating subsidiary has short-term cash surpluses or cash requirements, the Intermediate Partnership provides cash to the subsidiary or the subsidiary provides cash to the Intermediate Partnership.

Short-term Liquidity - Our principal sources of short-term liquidity consist of cash generated from operating activities, distributions received from our equity-method investments and proceeds from our commercial paper program, Partnership Credit Agreement and our "at-the-market" equity program.

We had working capital (defined as current assets less current liabilities) deficits of approximately $697 million and $1.3 billion as of December 31, 2015 and 2014, respectively. Although working capital is influenced by several factors, including, among other things, (i) the timing of (a) scheduled debt payments, (b) the collection and payment of accounts receivable and payable, and (c) equity and debt issuances, and (ii) the volume and cost of inventory and commodity imbalances, our working capital deficit at December 31, 2015, was driven primarily by our capital-growth projects. Our working capital deficit at December 31, 2014, was driven primarily by our capital-growth projects and our $800 million acquisition of West Texas LPG in November 2014, which were initially funded with short-term borrowings under our commercial paper program. We repaid these short-term borrowings with cash from operations, our March 2015 debt issuance, equity issued through our "at-the-market" equity program and our August 2015 equity issuances. We may have working capital deficits in future periods as we continue to finance our capital-growth projects, often initially with short-term borrowings. We do not expect our working capital deficit to have an adverse impact to our cash flows or operations.

At December 31, 2015, we had $246.3 million of commercial paper outstanding, $14 million of letters of credit issued and $300 million of borrowings outstanding under our Partnership Credit Agreement. At December 31, 2015, we had approximately $5.1 million of cash and cash equivalents and approximately $1.8 billion of credit available under the Partnership Credit Agreement.

The weighted-average interest rate at December 31, 2015, on our short-term borrowings was 1.43 percent. Based on the forward LIBOR curve, we expect the interest rates on our short-term borrowings to increase in 2016, compared with interest rates on amounts outstanding at December 31, 2015.

In January 2016, we extended the term of our Partnership Credit Agreement by one year to January 2020. Our Partnership Credit Agreement is a $2.4 billion revolving credit facility and includes a $100 million sublimit for the issuance of standby letters of credit, and a $150 million swingline sublimit. Our Partnership Credit Agreement is available for general partnership purposes. During the first quarter 2015, we increased the size of our Partnership Credit Agreement and commercial paper program each to $2.4 billion from $1.7 billion. Amounts outstanding under our commercial paper program reduce the borrowing capacity under our Partnership Credit Agreement.

Our Partnership Credit Agreement contains provisions for an applicable margin rate and an annual facility fee, both of which adjust with changes in our credit rating. Under the terms of the Partnership Credit Agreement, based on our current credit rating, borrowings, if any, will accrue at LIBOR plus 117.5 basis points, and the annual facility fee is 20 basis points. Our Partnership Credit Agreement is guaranteed fully and unconditionally by the Intermediate Partnership.

Our Partnership Credit Agreement contains certain financial, operational and legal covenants. Among other things, these covenants include maintaining a ratio of indebtedness to adjusted EBITDA (EBITDA, as defined in our Partnership Credit Agreement, adjusted for all noncash charges and increased for projected EBITDA from certain lender-approved capital expansion projects) of no more than 5.0 to 1. If we consummate one or more acquisitions in which the aggregate purchase price is $25 million or more, the allowable ratio of indebtedness to adjusted EBITDA will increase to 5.5 to 1 for the quarter in which the acquisition was completed and the two following quarters. As a result of the West Texas LPG acquisition we completed in the fourth quarter 2014, the allowable ratio of indebtedness to adjusted EBITDA increased to 5.5 to 1 through the second quarter 2015. If we were to breach certain covenants in our Partnership Credit Agreement, amounts outstanding under our Partnership Credit Agreement, if any, may become due and payable immediately. At December 31, 2015, our ratio of indebtedness to adjusted EBITDA was 4.4 to 1, and we were in compliance with all covenants under our Partnership Credit Agreement. At December 31, 2015, we could have issued $1.0 billion of incremental short- and long-term debt to meet our liquidity needs under the most restrictive provisions contained in our various borrowing agreements.

Borrowings under our Partnership Credit Agreement, Term Loan Agreement and our senior notes are nonrecourse to ONEOK, and ONEOK does not guarantee our debt, commercial paper or other similar commitments.

Long-term Financing - In addition to our principal sources of short-term liquidity discussed above, we expect to fund our longer-term financing requirements by issuing common units or long-term notes. Other options to obtain financing include, but are not limited to, issuance of convertible debt securities, asset securitization and the sale and lease back of facilities.

Our ability to obtain financing is subject to changes in the debt and equity markets, and there is no assurance we will be able or willing to access the public or private markets in the future. We may choose to meet our cash requirements by utilizing some combination of cash flows from operations, borrowing under our commercial paper program or our Partnership Credit Agreement, altering the timing of controllable expenditures, restricting future acquisitions and capital projects, selling assets or pursuing other debt or equity financing alternatives. Some of these alternatives could result in higher costs or negatively affect our credit ratings, among other factors. Based on our investment-grade credit ratings, general financial condition and expectations regarding our future earnings and projected cash flows, we expect to be able to meet our cash requirements and maintain investment-grade credit ratings.

Debt Issuances and Maturities - In January 2016, we entered into the $1.0 billion senior unsecured delayed-draw Term Loan Agreement with a syndicate of banks, which may be drawn by April 7, 2016. We expect to draw the full $1.0 billion available under the agreement and use the proceeds to effectively refinance our $650 million, 3.25 percent senior notes that matured on February 1, 2016, and our $450 million, 6.15 percent senior notes that mature on October 1, 2016. The Term Loan Agreement matures in January 2019 and will bear interest at LIBOR plus a margin that is based on the credit ratings assigned to our senior, unsecured, long-term indebtedness. Based on our current applicable credit rating, borrowings on the Term Loan Agreement will accrue at LIBOR plus 130.0 basis points. The Term Loan Agreement contains an option, which may be exercised up to two times, to extend the term of the loan, in each case, for an additional one-year term subject to approval of the banks. The Term Loan Agreement provides an option to prepay, without penalty or premium, the amount outstanding, or any portion thereof and contains substantially the same covenants as those contained in our Partnership Credit Agreement.

In March 2015, we completed an underwritten public offering of $800 million of senior notes, consisting of $300 million, 3.8 percent senior notes due 2020, and $500 million, 4.9 percent senior notes due 2025. The net proceeds, after deducting underwriting discounts, commissions and offering expenses, were approximately $792.3 million. We used the proceeds to repay amounts outstanding under our commercial paper program and for general partnership purposes.

In September 2013, we completed an underwritten public offering of $1.25 billion of senior notes, consisting of $425 million, 3.2 percent senior notes due 2018, $425 million, 5.0 percent senior notes due 2023 and $400 million, 6.2 percent senior notes due 2043. A portion of the net proceeds from the offering of approximately $1.24 billion was used to repay amounts outstanding under our commercial paper program, and the balance was used for general partnership purposes, including but not limited to capital expenditures and acquisitions.

Equity Issuances - In August 2015, we completed a private placement of 21.5 million common units at a price of $30.17 per unit with ONEOK. Additionally, we completed a concurrent sale of approximately 3.3 million common units at a price of $30.17 per unit to funds managed by Kayne Anderson Capital Advisors in a registered direct offering, which were issued through our existing "at-the-market" equity program. The combined offerings generated net cash proceeds of approximately $749 million. In conjunction with these issuances, ONEOK Partners GP contributed approximately $15.3 million in order to maintain its 2 percent general partner interest in us. We used the proceeds for general partnership purposes, including capital expenditures and repayment of commercial paper borrowings.

We have an "at-the-market" equity program for the offer and sale from time to time of our common units, up to an aggregate amount of $650 million. The program allows us to offer and sell our common units at prices we deem appropriate through a sales agent. Sales of common units are made by means of ordinary brokers' transactions on the NYSE, in block transactions or as otherwise agreed to between us and the sales agent. We are under no obligation to offer and sell common units under the program. At December 31, 2015, we had approximately $138 million of registered common units available for issuance through our "at-the-market" equity program.

During the year ended December 31, 2015, we sold 10.5 million common units through our "at-the-market" equity program, including the units sold to funds managed by Kayne Anderson Capital Advisors in the offering discussed above. The gross proceeds, including ONEOK Partners GP's contribution to maintain its 2 percent general partner interest in us, were approximately $384.4 million. Net cash proceeds, after deducting agent commissions and other related costs, were approximately $381.6 million, which were used for general partnership purposes, including repayment of commercial paper borrowings.

As a result of these transactions, ONEOK's aggregate ownership interest in us increased to 41.2 percent at December 31, 2015, from 37.8 percent at December 31, 2014.

In May 2014, we completed an underwritten public offering of 13.9 million common units at a public offering price of $52.94 per common unit, generating net proceeds of approximately $714.5 million. In conjunction with this issuance, ONEOK Partners GP contributed approximately $15.0 million in order to maintain its 2 percent general partner interest in us. We used the proceeds for general partnership purposes, including capital expenditures and repayment of commercial paper borrowings.

During the year ended December 31, 2014, we sold 7.9 million common units through our "at-the-market" equity program. The gross proceeds, including ONEOK Partners GP's contribution to maintain its 2 percent general partner interest in us, were approximately $408.1 million. Net cash proceeds, after deducting agent commissions and other related costs, were approximately $402.1 million, which were used for general partnership purposes.

In August 2013, we completed an underwritten public offering of 11.5 million common units at a public offering price of $49.61 per common unit, generating net proceeds of approximately $553.4 million. In conjunction with this issuance, ONEOK Partners GP contributed approximately $11.6 million in order to maintain its 2 percent general partner interest in us. We used a portion of the proceeds from our August 2013 equity issuance to repay amounts outstanding under our commercial paper program, and the balance was used for general partnership purposes.

During the year ended December 31, 2013, we sold 681,000 common units through our "at-the-market" equity program. The gross proceeds, including ONEOK Partners GP's contribution to maintain its 2 percent general partner interest in us, were approximately $36.6 million. Net cash proceeds, after deducting agent commissions and other related costs, were approximately $36.1 million, which were used for general partnership purposes.

Interest-rate Swaps - We have entered into forward-starting interest-rate swaps to hedge the variability of interest payments on a portion of forecasted debt issuances that may result from changes in the benchmark interest rate before the debt is issued. Upon our debt issuance in March 2015, we paid $55.1 million to settle $500 million of our interest-rate swaps. At

December 31, 2015, we had forward-starting interest-rate swaps with notional amounts totaling $400 million that were designated as cash flow hedges and have settlement dates of less than 12 months.

In January 2016, we entered into forward-starting interest-rate swaps with notional amounts totaling $1.0 billion for the period of April 2016 through July 2018 and forward-starting interest-rate swaps with notional amounts totaling $500 million for the period of July 2018 through January 2019 that were designated as cash flow hedges to hedge the variability of our LIBOR-based interest payments.

Capital Expenditures - We classify expenditures that are expected to generate additional revenue, return on investment or significant operating efficiencies as growth capital expenditures. Maintenance capital expenditures are those capital expenditures required to maintain our existing assets and operations and do not generate additional revenues. Maintenance capital expenditures are made to replace partially or fully depreciated assets, to maintain the existing operating capacity of our assets and to extend their useful lives. Our capital expenditures are financed typically through operating cash flows, short- and long-term debt and the issuance of equity.

Capital expenditures were approximately $1.2 billion, $1.7 billion and $1.9 billion for 2015, 2014 and 2013, respectively. Capital expenditures in 2015 were less than 2014 capital expenditures due primarily to the completion of several large projects in 2014. We realigned our capital-growth projects with the needs of our crude oil and natural gas producer customers, which included suspending, reducing or eliminating certain capital-growth projects to reduce our capital expenditures. Capital expenditures decreased for 2014, compared with 2013, due primarily to the timing of expenditures on growth projects in our Natural Gas Gathering and Processing and Natural Gas Liquids segments.

The following tables set forth our growth and maintenance capital expenditures, excluding AFUDC, for the periods indicated:

Growth Capital Expenditures	**2015**	**2014**	**2013**
		(Millions of dollars)	
Natural Gas Gathering and Processing	**$ 845.3**	$ 858.0	$ 747.6
Natural Gas Liquids	**190.5**	751.4	1,087.8
Natural Gas Pipelines	**34.7**	9.7	11.4
Total growth capital expenditures	**$ 1,070.5**	$ 1,619.1	$ 1,846.8

Maintenance Capital Expenditures	**2015**	**2014**	**2013**
		(Millions of dollars)	
Natural Gas Gathering and Processing	**$ 42.6**	$ 40.9	$ 26.8
Natural Gas Liquids	**35.6**	46.6	40.5
Natural Gas Pipelines	**23.5**	33.3	23.3
Other	**13.9**	6.1	1.9
Total maintenance capital expenditures	**$ 115.6**	$ 126.9	$ 92.5

In addition to the capital expenditures discussed above, we completed the acquisition of the West Texas LPG system from affiliates of Chevron Corporation for approximately $800 million in November 2014. In 2013, we completed the Sage Creek acquisition of certain natural gas gathering and processing and natural gas liquids facilities in Converse and Campbell counties, Wyoming, in the NGL-rich Niobrara Shale formation of the Powder River Basin for $305 million. We also acquired the remaining 30 percent undivided interest in the Maysville, Oklahoma, natural gas processing facility for $90 million during 2013. For additional discussion, see Note B to the Notes to Consolidated Financial Statements.

The following table summarizes our 2016 projected growth and maintenance capital expenditures, excluding AFUDC:

2016 Projected Capital Expenditures	**Growth**	**Maintenance**	**Total**
		(Millions of dollars)	
Natural Gas Gathering and Processing	$ 320	$ 35	$ 355
Natural Gas Liquids	70	55	125
Natural Gas Pipelines	70	30	100
Other	—	20	20
Total projected capital expenditures	$ 460	$ 140	$ 600

In 2016, we expect lower capital spending, compared with spending levels from 2013 through 2015, due to the current commodity price environment and alignment of our capital-growth projects with the needs of our customers. We expect to finance 2016 capital expenditures with cash flows from operations and short-term borrowings and do not expect a need to issue public debt or equity in 2016 and well into 2017. However, we may access the capital markets to issue debt or equity securities prior to that time as we consider prudent to provide liquidity for new capital projects, to maintain investment-grade credit ratings or other partnership purposes.

Unconsolidated Affiliates - The Overland Pass Pipeline Company limited liability company agreement provides that distributions to Overland Pass Pipeline Company's members are to be made on a pro rata basis according to each member's ownership interest. The Overland Pass Pipeline Company Management Committee determines the amount and timing of such distributions. Any changes to, or suspension of, cash distributions from Overland Pass Pipeline Company requires the unanimous approval of the Overland Pass Pipeline Management Committee. Cash distributions are equal to 100 percent of available cash as defined in the limited liability company agreement.

The Northern Border Pipeline partnership agreement provides that distributions to Northern Border Pipeline's partners are to be made on a pro rata basis according to each partner's percentage interest. The Northern Border Pipeline Management Committee determines the amount and timing of such distributions. Any changes to, or suspension of, the cash distribution policy of Northern Border Pipeline requires the unanimous approval of the Northern Border Pipeline Management Committee. Cash distributions are equal to 100 percent of distributable cash flow as determined from Northern Border Pipeline's financial statements based upon EBITDA less interest expense and maintenance capital expenditures. Loans or other advances from Northern Border Pipeline to its partners or affiliates are prohibited under its credit agreement.

The Roadrunner limited liability agreement provides that distributions to members are made on a pro rata basis according to each member's ownership interest. Cash distributions are paid within 45 days following the end of each quarter. Any changes to, or suspension of, the cash distributions from Roadrunner requires approval of the Roadrunner Management Committee. Voting rights for the Roadrunner Management Committee are allocated on a pro rata basis according to each member's ownership interest. Cash distributions are equal to 100 percent of available cash, as defined in the limited liability company agreement.

West Texas LPG Pipeline - The limited partnership agreement of WTLPG provides that distributions to the partners are to be made on a pro rata basis according to each partner's ownership interest. Cash distributions to the partners are currently declared and paid by WTLPG each calendar quarter. Any changes to, or suspension of, the cash distributions from WTLPG requires the approval of a minimum of 90 percent of the ownership interest and a minimum of two general partners of WTLPG. Cash distributions are equal to 100 percent of distributable cash as defined in the limited partnership agreement of WTLPG.

Credit Ratings - Our long-term debt credit ratings as of February 16, 2016, are shown in the table below:

Rating Agency	Rating	Outlook
Moody's	Baa2	Negative
S&P	BBB	Negative

Our commercial paper program is rated Prime-2 by Moody's and A-2 by S&P. In August 2015, Moody's and S&P affirmed our current credit ratings and revised our outlook to negative from stable. Our credit ratings, which are investment grade, may be affected by a material change in our financial ratios or a material event affecting our business and industry. The most common criteria for assessment of our credit ratings are the debt-to-EBITDA ratio, interest coverage, business risk profile and liquidity.

Recent declines in the energy commodity price environment and its impact on our results of operations and cash flows could cause the credit rating agencies to downgrade our credit ratings. If our credit ratings were downgraded, our cost to borrow funds under our commercial paper program or Partnership Credit Agreement would increase, and a potential loss of access to the commercial paper market could occur. In the event that we are unable to borrow funds under our commercial paper program and there has not been a material adverse change in our business, we would continue to have access to our Partnership Credit Agreement, which expires in January 2020. An adverse credit rating change alone is not a default under our Partnership Credit Agreement.

In the normal course of business, our counterparties provide us with secured and unsecured credit. In the event of a downgrade in our credit ratings or a significant change in our counterparties' evaluation of our creditworthiness, we could be required to provide additional collateral in the form of cash, letters of credit or other negotiable instruments as a condition of continuing to conduct business with such counterparties. We may be required to fund margin requirements with our counterparties with cash, letters of credit or other negotiable instruments.

Cash Distributions - We distribute 100 percent of our available cash, as defined in our Partnership Agreement, that generally consists of all cash receipts less adjustments for cash disbursements and net change to reserves, to our general and limited partners. Distributions are allocated to our general partner and limited partners according to their partnership percentages of 2 percent and 98 percent, respectively. The effect of any incremental allocations for incentive distributions to our general partner is calculated after the allocation to the general partner's partnership interest and before the allocation to the limited partners.

In the second and third quarters of 2015, our cash flow from operations exceeded our cash distributions. However, for the year ended December 31, 2015, our cash distributions exceeded our cash flow from operations. As a result, we utilized cash from operations, our commercial paper program and distributions received from our equity-method investments to fund our cash distributions. We expect increases in cash flows from operations in 2016, compared with 2015, due primarily to completion of our growth projects that we expect will provide increasing volumes in our Natural Gas Gathering and Processing and Natural Gas Liquids segments and higher fee revenues as a result of restructured contracts that we expect will provide increasing operating income in our Natural Gas Gathering and Processing segment.

The following table sets forth cash distributions paid, including our general partner's incentive distribution rights, during the periods indicated:

	Years Ended December 31,		
	2015	**2014**	**2013**
	(*Millions of dollars*)		
Common unitholders	**$ 603.8**	$ 506.5	$ 430.4
Class B unitholders	**230.6**	219.7	209.5
General partner	**396.1**	326.0	269.8
Noncontrolling interests	**11.7**	0.5	0.6
Total cash distributions paid	**$ 1,242.2**	$ 1,052.7	$ 910.3

For the years ended December 31, 2015, 2014 and 2013, cash distributions paid to our general partner included incentive distributions of $371.5 million, $305.0 million and $251.7 million, respectively.

In January 2016, our general partner declared a cash distribution of $0.79 per unit ($3.16 per unit on an annualized basis) for the fourth quarter 2015, which was paid on February 12, 2016, to unitholders of record as of February 1, 2016.

Additional information about our cash distributions is included in "Cash Distribution Policy" under Part II, Item 5, Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities, and Item 13, Certain Relationships and Related Transactions, and Director Independence.

Energy Commodity Prices - We are subject to commodity price volatility. Significant fluctuations in commodity prices will affect our overall liquidity due to the impact commodity price changes have on our cash flows from operating activities, including the impact on working capital for NGLs and natural gas held in storage, margin requirements and certain energy-related receivables. The decline in commodity prices has contributed to a decrease in our common unit price. While lower commodity prices and industry uncertainty may result in increased financing costs, we believe we have secured sufficient access to the financial resources and liquidity necessary to meet our requirements for working capital, debt service payments and capital expenditures through 2016 and well into 2017. We believe that our available credit and cash and cash equivalents are adequate to meet liquidity requirements associated with commodity price volatility. See discussion under "Commodity Price Risk" in Item 7A, Quantitative and Qualitative Disclosures about Market Risk, for information on our hedging activities.

CASH FLOW ANALYSIS

We use the indirect method to prepare our Consolidated Statements of Cash Flows. Under this method, we reconcile net income to cash flows provided by operating activities by adjusting net income for those items that affect net income but do not result in actual cash receipts or payments during the period and for operating cash items that do not impact net income. These reconciling items include depreciation and amortization, allowance for equity funds used during construction, gain or loss on sale of assets, deferred income taxes, equity in net earnings from investments, distributions received from unconsolidated affiliates, other amounts and changes in our assets and liabilities not classified as investing or financing activities.

The following table sets forth the changes in cash flows by operating, investing and financing activities for the periods indicated:

	Years Ended December 31, 2015	2014	2013
	(Millions of dollars)		
Total cash provided by (used in):			
Operating activities	**$ 1,072.0**	$ 1,309.8	$ 1,007.7
Investing activities	**(1,188.5)**	(2,533.0)	(2,326.1)
Financing activities	**79.1**	1,131.2	915.8
Change in cash and cash equivalents	**(37.4)**	(92.0)	(402.6)
Cash and cash equivalents at beginning of period	**42.5**	134.5	537.1
Cash and cash equivalents at end of period	**$ 5.1**	$ 42.5	$ 134.5

Operating Cash Flows - Operating cash flows are affected by earnings from our business activities. Changes in commodity prices and demand for our services or products, whether because of general economic conditions, changes in supply, changes in demand for the end products that are made with our products or increased competition from other service providers, could affect our earnings and operating cash flows.

2015 vs. 2014 - Cash flows from operating activities, before changes in operating assets and liabilities, were $1.2 billion for 2015, compared with $1.3 billion for 2014. The decrease was due primarily to increases in interest expense and operating costs, offset partially by a modest increase in operating income provided by revenues less cost of sales and fuel as discussed in "Financial Results and Operating Information." Distributions received from unconsolidated affiliates also increased, due primarily to Overland Pass Pipeline.

The changes in operating assets and liabilities decreased operating cash flows $135.5 million for 2015, compared with an increase of $41.0 million for 2014. This change is due primarily to the change in accounts receivable and accounts payable resulting from the timing of receipt of cash from customers and payments to vendors and suppliers, which vary from period to period and vary with changes in commodity prices. In the first quarter 2015, we also paid $55.1 million to settle forward-starting interest-rate swaps in connection with our March 2015 debt offering.

2014 vs. 2013 - Cash flows from operating activities, before changes in operating assets and liabilities, were $1.3 billion for 2014, compared with $1.0 billion for 2013. The increase was due primarily to an increase in operating income provided by revenues less cost of sales and fuel as discussed in "Financial Results and Operating Information." Distributions received from unconsolidated affiliates also increased, due primarily to Norther Border Pipeline.

The changes in operating assets and liabilities increased operating cash flows $41.0 million for 2014, compared with an increase of $8.1 million for 2013. This change is due primarily to the change in accounts receivable and accounts payable resulting from the timing of receipt of cash from customers and payments to vendors and suppliers, which vary from period to period, and the decrease in commodity imbalances. This change is also due to the change in NGL volumes in storage and commodity imbalances.

Investing Cash Flows - Cash used in investing activities decreased for 2015, compared with 2014, due primarily to the completion of growth projects, the West Texas LPG acquisition in 2014 and the timing of capital expenditures for our growth projects in our Natural Gas Gathering and Processing and Natural Gas Liquids segments, offset partially by contributions made to Roadrunner in 2015. We also had an acquisition in the first quarter 2014 in our Natural Gas Pipelines segment.

Cash used in investing activities increased for 2014, compared with 2013, due primarily to the cash paid for the West Texas LPG acquisition. This increase was offset partially by decreased capital expenditures primarily in our Natural Gas Liquids segment due to the timing of expenditures on our growth projects.

Financing Cash Flows - Cash provided by financing activities decreased for 2015, compared with 2014, due primarily to decreased borrowings due to decreased capital expenditures, and increased distributions paid due to a higher number of units outstanding and a higher distribution per unit.

Cash provided by financing activities increased for 2014, compared with 2013, due primarily to proceeds from the short-term borrowings associated with completing the West Texas LPG acquisition and increased proceeds from our issuances of common units. These increases were offset partially by higher distributions paid.

IMPACT OF NEW ACCOUNTING STANDARDS

Information about the impact of new accounting standards is included in Note A of the Notes to Consolidated Financial Statements in this Annual Report.

ESTIMATES AND CRITICAL ACCOUNTING POLICIES

The preparation of our consolidated financial statements and related disclosures in accordance with GAAP requires us to make estimates and assumptions with respect to values or conditions that cannot be known with certainty that affect the reported amounts of assets and liabilities, and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements. These estimates and assumptions also affect the reported amounts of revenue and expenses during the reporting period. Although we believe these estimates and assumptions are reasonable, actual results could differ from our estimates.

The following is a summary of our most critical accounting policies, which are defined as those estimates and policies most important to the portrayal of our financial condition and results of operations and requiring our management's most difficult, subjective or complex judgment, particularly because of the need to make estimates concerning the impact of inherently uncertain matters. We have discussed the development and selection of our estimates and critical accounting policies with the Audit Committee of the Board of Directors of ONEOK Partners GP.

Derivatives and Risk-Management Activities - We utilize derivatives to reduce our market-risk exposure to commodity price and interest-rate fluctuations and to achieve more predictable cash flows. The accounting for changes in the fair value of a derivative instrument depends on whether it qualifies and has been designated as part of a hedging relationship. When possible, we implement effective hedging strategies using derivative financial instruments that qualify as hedges for accounting purposes. We have not used derivative instruments for trading purposes.

For a derivative designated as a cash flow hedge, the effective portion of the gain or loss from a change in fair value of the derivative instrument is deferred in accumulated other comprehensive income (loss) until the forecasted transaction affects earnings, at which time the fair value of the derivative instrument is reclassified into earnings. The ineffective portion of the gain or loss on a derivative instrument designated as a cash flow hedge is recognized in earnings.

We assess the effectiveness of hedging relationships quarterly by performing an effectiveness test on our hedging relationships to determine whether they are highly effective on a retrospective and prospective basis. We do not believe that changes in our fair value estimates of our derivative instruments have a material impact on our results of operations, as the majority of our derivatives are accounted for as cash flow hedges for which ineffectiveness is not material. However, if a derivative instrument is ineligible for cash flow hedge accounting or if we fail to appropriately designate it as a cash flow hedge, changes in fair value of the derivative instrument would be recorded currently in earnings. Additionally, if a cash flow hedge ceases to qualify for hedge accounting treatment because it is no longer probable that the forecasted transaction will occur, the change in fair value of the derivative instrument would be recognized in earnings. For more information on commodity price sensitivity and a discussion of the market risk of pricing changes, see Item 7A, Quantitative and Qualitative Disclosures about Market Risk.

See Notes C and D of the Notes to Consolidated Financial Statements in this Annual Report for additional discussion of fair value measurements and derivatives and risk-management activities.

Impairment of Goodwill and Long-Lived Assets, including Intangible Assets - We assess our goodwill for impairment at least annually on July 1, unless events or changes in circumstances indicate an impairment may have occurred before that time. While there have been sharp declines in commodity prices over the past year, we are responding to the low commodity price environment by suspending certain capital-growth projects, aligning operating costs with the needs of our crude oil and natural gas producer customers, utilizing hedging to partially mitigate the low commodity prices and actively working to increase the fee-based component in the POP with fee contracts in our Natural Gas Gathering and Processing segment, which is the segment with the most commodity price exposure. Each reporting period, we assess these qualitative factors to determine whether it is more likely than not that the fair value of each of our reporting units is less than its carrying amount. At July 1, 2015, due to the current commodity price environment, we elected to perform a quantitative assessment, or Step 1 analysis, to test our goodwill for impairment. The assessment included our commodity price assumptions, expected contractual terms, anticipated operating costs and volume estimates. Our goodwill impairment analysis performed as of July 1, 2015, did not result in an impairment charge nor did our analysis reflect any reporting units at risk. In each reporting unit, the fair value substantially exceeded its carrying value. At December 31, 2015, we performed a qualitative review given the decline in commodity prices and our unit price since our assessment as of July 1, 2015, and determined that no event has occurred indicating that the implied fair value of each of our reporting units is less than the carrying value of its net assets.

As part of our goodwill impairment test, we may first assess qualitative factors (including macroeconomic conditions, industry and market considerations, cost factors and overall financial performance) to determine whether it is more likely than not that the fair value of each of our reporting units is less than its carrying amount. If further testing is necessary or a quantitative test is elected, we perform a two-step impairment test for goodwill. In the first step, an initial assessment is made by comparing the fair value of a reporting unit with its book value, including goodwill. If the fair value is less than the book value, an impairment is indicated, and we must perform a second test to measure the amount of the impairment. In the second test, we calculate the implied fair value of the goodwill by deducting the fair value of all tangible and intangible net assets of the reporting unit from the fair value determined in step one of the assessment. If the carrying value of the goodwill exceeds the implied fair value of the goodwill, we will record an impairment charge.

To estimate the fair value of our reporting units, we use two generally accepted valuation approaches, an income approach and a market approach, using assumptions consistent with a market participant's perspective. Under the income approach, we use anticipated cash flows over a period of years plus a terminal value and discount these amounts to their present value using appropriate discount rates. Under the market approach, we apply EBITDA multiples to forecasted EBITDA. The multiples used are consistent with historical asset transactions. The forecasted cash flows are based on average forecasted cash flows for a reporting unit over a period of years.

The following table sets forth our goodwill, by segment, for the periods indicated:

	December 31, 2015	December 31, 2014
	(*Thousands of dollars*)	
Natural Gas Gathering and Processing	**$ 112,141**	$ 112,141
Natural Gas Liquids	**247,566**	247,566
Natural Gas Pipelines	**129,011**	129,011
Total goodwill	**$ 488,718**	$ 488,718

We assess our long-lived assets, including intangible assets with finite useful lives, for impairment whenever events or changes in circumstances indicate that an asset's carrying amount may not be recoverable. An impairment is indicated if the carrying amount of a long-lived asset exceeds the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If an impairment is indicated, we record an impairment loss equal to the difference between the carrying value and the fair value of the long-lived asset.

For the investments we account for under the equity method, the impairment test considers whether the fair value of the equity investment as a whole, not the underlying net assets, has declined and whether that decline is other than temporary. Therefore, we periodically reevaluate the amount at which we carry our equity-method investments to determine whether current events or circumstances warrant adjustments to our carrying value.

Impairment Charges - We recorded $264.3 million and $76.4 million of noncash impairment charges primarily related to our long-lived assets and equity investments in the dry natural gas area of the Powder River Basin in 2015 and 2014, respectively.

Our impairment tests require the use of assumptions and estimates such as industry economic factors and the profitability of future business strategies. If actual results are not consistent with our assumptions and estimates or our assumptions and estimates change due to new information, we may be exposed to future impairment charges.

See Notes A, E, F and M of the Notes to Consolidated Financial Statements in this Annual Report for additional discussion of goodwill, long-lived assets and investments in unconsolidated affiliates.

Contingencies - Our accounting for contingencies covers a variety of business activities, including contingencies for legal and environmental exposures. We accrue these contingencies when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered, and an amount can be reasonably estimated. We expense legal fees as incurred and base our legal liability estimates on currently available facts and our assessments of the ultimate outcome or resolution. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than the completion of a remediation feasibility study. Recoveries of environmental remediation costs from other parties are recorded as assets when their receipt is deemed probable. Our expenditures for environmental evaluation, mitigation, remediation and compliance to date have not been significant in relation to our financial position or results of operations, and our expenditures related to environmental matters had no material effect on earnings or cash flows during 2015, 2014 or 2013. Actual results may differ from our estimates resulting in an impact, positive or negative, on earnings.

See Note O of the Notes to Consolidated Financial Statements in this Annual Report for additional discussion of contingencies.

CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

The following table sets forth our contractual obligations related to debt, operating leases and other long-term obligations as of December 31, 2015. For additional discussion of the debt agreements, see Note H of the Notes to Consolidated Financial Statements in this Annual Report.

	Payments Due by Period						
Contractual Obligations	**Total**	**2016**	**2017**	**2018**	**2019**	**2020**	**Thereafter**
				(*Millions of dollars*)			
ONEOK Partners senior notes	$ 6,800.0	$ 1,100.0	$ 400.0	$ 425.0	$ 500.0	$ 300.0	$ 4,075.0
Guardian Pipeline senior notes	51.9	7.7	7.7	7.7	7.7	7.7	13.4
Interest payments on debt	4,284.1	324.7	299.1	288.5	242.3	233.2	2,896.3
Short-term borrowings	546.3	546.3	—	—	—	—	—
Operating leases	12.4	2.3	1.7	1.7	1.4	1.0	4.3
Firm transportation and storage contracts	248.4	45.8	42.1	40.6	36.2	35.8	47.9
Financial and physical derivatives	121.6	121.6	—	—	—	—	—
Purchase commitments, rights of way and other	305.4	74.3	74.1	74.4	31.2	31.3	20.1
Total	$ 12,370.1	$ 2,222.7	$ 824.7	$ 837.9	$ 818.8	$ 609.0	$ 7,057.0

ONEOK Partners senior notes, Guardian Pipeline senior notes and notes payable - The amount of principal due in each period.

Interest payments on debt - Interest payments are calculated by multiplying long-term debt principal amount by the respective coupon rates.

Operating leases - Our operating leases include leases for office space and pipeline equipment.

Firm transportation and storage contracts - Our Natural Gas Gathering and Processing and Natural Gas Liquids segments are party to fixed-price contracts for firm transportation and storage capacity.

Financial and physical derivatives - These are obligations arising from our fixed- and variable-price purchase commitments for physical and financial commodity derivatives. Estimated future variable-price purchase commitments are based on market information at December 31, 2015. Actual future variable-price purchase obligations may vary depending on market prices at the time of delivery. Sales of the related physical volumes and net positive settlements of financial derivatives are not reflected in the table above.

Purchase commitments, rights of way and other - Purchase commitments include commitments related to our growth capital expenditures and other rights-of-way and contractual commitments. Purchase commitments exclude commodity purchase contracts, which are included in the "Financial and physical derivatives" amounts.

FORWARD-LOOKING STATEMENTS

Some of the statements contained and incorporated in this Annual Report are forward-looking statements as defined under federal securities laws. The forward-looking statements relate to our anticipated financial performance (including projected operating income, net income, capital expenditures, cash flow and projected levels of distributions), liquidity, management's plans and objectives for our future growth projects and other future operations (including plans to construct additional natural gas and natural gas liquids pipelines and processing facilities and related cost estimates), our business prospects, the outcome of regulatory and legal proceedings, market conditions and other matters. We make these forward-looking statements in reliance on the safe harbor protections provided under federal securities legislation and other applicable laws. The following discussion is intended to identify important factors that could cause future outcomes to differ materially from those set forth in the forward-looking statements.

Forward-looking statements include the items identified in the preceding paragraph, the information concerning possible or assumed future results of our operations and other statements contained or incorporated in this Annual Report identified by words such as “anticipate,” “estimate,” “expect,” “project,” “intend,” “plan,” “believe,” “should,” “goal,” “forecast,” “guidance,” “could,” “may,” “continue,” “might,” “potential,” “scheduled” and other words and terms of similar meaning.

One should not place undue reliance on forward-looking statements. Known and unknown risks, uncertainties and other factors may cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by forward-looking statements. Those factors may affect our operations, markets, products, services and prices. In addition to any assumptions and other factors referred to specifically in connection with the forward-looking statements, factors that could cause our actual results to differ materially from those contemplated in any forward-looking statement include, among others, the following:

- the effects of weather and other natural phenomena, including climate change, on our operations, demand for our services and energy prices;
- competition from other United States and foreign energy suppliers and transporters, as well as alternative forms of energy, including, but not limited to, solar power, wind power, geothermal energy and biofuels such as ethanol and biodiesel;
- the capital intensive nature of our businesses;
- the profitability of assets or businesses acquired or constructed by us;
- our ability to make cost-saving changes in operations;
- risks of marketing, trading and hedging activities, including the risks of changes in energy prices or the financial condition of our counterparties;
- the uncertainty of estimates, including accruals and costs of environmental remediation;
- the timing and extent of changes in energy commodity prices;
- the effects of changes in governmental policies and regulatory actions, including changes with respect to income and other taxes, pipeline safety, environmental compliance, climate change initiatives and authorized rates of recovery of natural gas and natural gas transportation costs;
- the impact on drilling and production by factors beyond our control, including the demand for natural gas and crude oil; producers’ desire and ability to obtain necessary permits; reserve performance; and capacity constraints on the pipelines that transport crude oil, natural gas and NGLs from producing areas and our facilities;
- difficulties or delays experienced by trucks, railroads or pipelines in delivering products to or from our terminals or pipelines;
- changes in demand for the use of natural gas, NGLs and crude oil because of market conditions caused by concerns about climate change;
- conflicts of interest between us, our general partner, ONEOK Partners GP, and related parties of ONEOK Partners GP;
- the impact of unforeseen changes in interest rates, equity markets, inflation rates, economic recession and other external factors over which we have no control;
- our indebtedness could make us vulnerable to general adverse economic and industry conditions, limit our ability to borrow additional funds and/or place us at competitive disadvantages compared with our competitors that have less debt or have other adverse consequences;
- actions by rating agencies concerning the credit ratings of us or the parent of our general partner;
- the results of administrative proceedings and litigation, regulatory actions, rule changes and receipt of expected clearances involving any local, state or federal regulatory body, including the FERC, the National Transportation Safety Board, the PHMSA, the EPA and CFTC;
- our ability to access capital at competitive rates or on terms acceptable to us;
- risks associated with adequate supply to our gathering, processing, fractionation and pipeline facilities, including production declines that outpace new drilling or extended periods of ethane rejection;
- the risk that material weaknesses or significant deficiencies in our internal controls over financial reporting could emerge or that minor problems could become significant;
- the impact and outcome of pending and future litigation;
- the ability to market pipeline capacity on favorable terms, including the effects of:
    - future demand for and prices of natural gas, NGLs and crude oil;
    - competitive conditions in the overall energy market;
    - availability of supplies of Canadian and United States natural gas and crude oil; and
    - availability of additional storage capacity;
- performance of contractual obligations by our customers, service providers, contractors and shippers;
- the timely receipt of approval by applicable governmental entities for construction and operation of our pipeline and other projects and required regulatory clearances;

- our ability to acquire all necessary permits, consents or other approvals in a timely manner, to promptly obtain all necessary materials and supplies required for construction, and to construct gathering, processing, storage, fractionation and transportation facilities without labor or contractor problems;
- the mechanical integrity of facilities operated;
- demand for our services in the proximity of our facilities;
- our ability to control operating costs;
- acts of nature, sabotage, terrorism or other similar acts that cause damage to our facilities or our suppliers' or shippers' facilities;
- economic climate and growth in the geographic areas in which we do business;
- the risk of a prolonged slowdown in growth or decline in the United States or international economies, including liquidity risks in United States or foreign credit markets;
- the impact of recently issued and future accounting updates and other changes in accounting policies;
- the possibility of future terrorist attacks or the possibility or occurrence of an outbreak of, or changes in, hostilities or changes in the political conditions in the Middle East and elsewhere;
- the risk of increased costs for insurance premiums, security or other items as a consequence of terrorist attacks;
- risks associated with pending or possible acquisitions and dispositions, including our ability to finance or integrate any such acquisitions and any regulatory delay or conditions imposed by regulatory bodies in connection with any such acquisitions and dispositions;
- the impact of uncontracted capacity in our assets being greater or less than expected;
- the ability to recover operating costs and amounts equivalent to income taxes, costs of property, plant and equipment and regulatory assets in our state and FERC-regulated rates;
- the composition and quality of the natural gas and NGLs we gather and process in our plants and transport on our pipelines;
- the efficiency of our plants in processing natural gas and extracting and fractionating NGLs;
- the impact of potential impairment charges;
- the risk inherent in the use of information systems in our respective businesses, implementation of new software and hardware, and the impact on the timeliness of information for financial reporting;
- our ability to control construction costs and completion schedules of our pipelines and other projects; and
- the risk factors listed in the reports we have filed and may file with the SEC, which are incorporated by reference.

These factors are not necessarily all of the important factors that could cause actual results to differ materially from those expressed in any of our forward-looking statements. Other factors could also have material adverse effects on our future results. These and other risks are described in greater detail in Part I, Item 1A, Risk Factors, in this Annual Report and in our other filings that we make with the SEC, which are available via the SEC's website at www.sec.gov and our website at www.oneokpartners.com. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these factors. Any such forward-looking statement speaks only as of the date on which such statement is made, and other than as required under securities laws, we undertake no obligation to update publicly any forward-looking statement whether as a result of new information, subsequent events or change in circumstances, expectations or otherwise.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our exposure to market risk discussed below includes forward-looking statements and represents an estimate of possible changes in future earnings that could occur assuming hypothetical future movements in interest rates or commodity prices. Our views on market risk are not necessarily indicative of actual results that may occur and do not represent the maximum possible gains and losses that may occur since actual gains and losses will differ from those estimated based on actual fluctuations in interest rates or commodity prices and the timing of transactions.

We are exposed to market risk due to commodity price and interest-rate volatility. Market risk is the risk of loss arising from adverse changes in market rates and prices. We may use financial instruments, including forward sales, swaps, options and futures, to manage the risks of certain identifiable or anticipated transactions and achieve a more predictable cash flow. Our risk-management function follows established policies and procedures to monitor our natural gas, condensate and NGL marketing activities and interest rates to ensure our hedging activities mitigate market risks. We do not use financial instruments for trading purposes.

We record derivative instruments at fair value. We estimate the fair value of derivative instruments using available market information and appropriate valuation techniques. Changes in derivative instruments' fair values are recognized in earnings unless the instrument qualifies as a hedge and meets specific hedge accounting criteria. The effective portion of qualifying derivative instruments' gains and losses may offset the hedged items' related results in earnings for a fair value hedge or be deferred in accumulated other comprehensive income (loss) for a cash flow hedge.

COMMODITY PRICE RISK

Although our businesses are predominately fee based, in our Natural Gas Gathering and Processing segment, we are exposed to commodity price risk as a result of receiving commodities as a portion of our compensation for services associated with our POP with fee contracts. We have restructured a portion of our POP with fee contracts to include significantly higher fees, which reduces our equity volumes and the related commodity price exposure. However, under certain POP with fee contracts our fee revenues may increase or decrease if production volumes, delivery pressures or commodity prices change relative to specified thresholds.

We also are exposed to basis risk between the various production and market locations where we receive and sell commodities.

As part of our hedging strategy, we use the previously described commodity derivative financial instruments and physical-forward contracts to minimize the impact of near-term price fluctuations related to natural gas, NGLs and condensate. As of December 31, 2015, we had $49.8 million of commodity-related derivative assets and $8.0 million of commodity-related derivative liabilities, excluding the impact of netting.

The following tables set forth hedging information for our Natural Gas Gathering and Processing segment's forecasted equity volumes for the periods indicated:

	Year Ending December 31, 2016		
	Volumes Hedged	**Average Price**	**Percentage Hedged**
NGLs - excluding ethane (*MBbl/d*) - Conway/Mont Belvieu	7.9	$ 0.48 / gallon	80%
Condensate (*MBbl/d*) - WTI-NYMEX	1.7	$ 59.24 / Bbl	57%
Natural gas (*BBtu/d*) - NYMEX and basis	74.1	$ 2.96 / MMBtu	83%

	Year Ending December 31, 2017		
	Volumes Hedged	**Average Price**	**Percentage Hedged**
NGLs - excluding ethane (*MBbl/d*) - Conway/Mont Belvieu	1.0	$ 0.40 / gallon	9%
Condensate (*MBbl/d*) - WTI-NYMEX	1.5	$ 43.65 / Bbl	49%
Natural gas (*BBtu/d*) - NYMEX and basis	50.6	$ 2.62 / MMBtu	48%

We expect our natural gas liquids and natural gas commodity price sensitivity within this segment to decrease in 2016, compared with 2015, as a result of the restructured contracts completed in 2015. Our Natural Gas Gathering and Processing segment's commodity price sensitivity is estimated as a hypothetical change in the price of NGLs, crude oil and natural gas at December 31, 2015, excluding the effects of hedging and assuming normal operating conditions. Our condensate sales are based on the price of crude oil. We estimate the following for our forecasted equity volumes:

- a $0.01 per-gallon change in the composite price of NGLs would change 12-month operating income by approximately $1.8 million for the year ending December 31, 2016, compared with approximately $3.0 million estimated at December 31, 2014 for the year ended December 31, 2015;
- a $1.00 per-barrel change in the price of crude oil would change 12-month operating income by approximately $1.3 million for the year ending December 31, 2016, compared with approximately $1.6 million estimated at December 31, 2014 for the year ended December 31, 2015 ; and
- a $0.10 per-MMBtu change in the price of residue natural gas would change 12-month operating income by approximately $3.3 million for the year ending December 31, 2016, compared with approximately $5.2 million estimated at December 31, 2014 for the year ended December 31, 2015.

We estimate the following for our forecasted equity volumes, including the effects of hedging information set forth above, and assuming normal operating conditions, for the year ending December 31, 2016:

- a $0.01 per-gallon change in the composite price of NGLs would change 12-month operating income by approximately $0.6 million;
- a $1.00 per-barrel change in the price of crude oil would change 12-month operating income by approximately $0.7 million; and

- a \$0.10 per-MMBtu change in the price of residue natural gas would change 12-month operating income by approximately \$0.5 million.

These estimates do not include any effects on demand for our services or natural gas processing plant operations that might be caused by, or arise in conjunction with, commodity price fluctuations. For example, a change in the gross processing spread may cause a change in the amount of ethane extracted from the natural gas stream, impacting gathering and processing financial results for certain contracts.

In our Natural Gas Liquids segment, we are exposed to location price differential risk primarily as a result of the relative value of NGL purchases at one location and sales at another location. To a lesser extent, we are exposed to commodity price risk resulting from the relative values of the various NGL products to each other, NGLs in storage and the relative value of NGLs to natural gas. We utilize physical-forward contracts and commodity derivative financial instruments to reduce the impact of price fluctuations related to NGLs.

In our Natural Gas Pipelines segment, we are exposed to commodity price risk because our intrastate and interstate natural gas pipelines retain natural gas from our customers for operations or as part of our fee for services provided. When the amount of natural gas consumed in operations by these pipelines differs from the amount provided by our customers, our pipelines must buy or sell natural gas, or store or use natural gas from inventory, which can expose us to commodity price risk depending on the regulatory treatment for this activity. To the extent that commodity price risk in our Natural Gas Pipelines segment is not mitigated by fuel cost-recovery mechanisms, we use physical-forward sales or purchases to reduce the impact of price fluctuations related to natural gas. At December 31, 2015 and 2014, there were no financial derivative instruments with respect to our natural gas pipeline operations.

See Note D of the Notes to Consolidated Financial Statements in this Annual Report for more information on our hedging activities.

INTEREST-RATE RISK

We are exposed to interest-rate risk through our Partnership Credit Agreement, commercial paper program and long-term debt issuances. Future increases in LIBOR, corporate commercial paper rates or investment-grade corporate bond rates could expose us to increased interest costs on future borrowings. We manage interest-rate risk through the use of fixed-rate debt, floating-rate debt and interest-rate swaps. Interest-rate swaps are agreements to exchange interest payments at some future point based on specified notional amounts. At December 31, 2015 and 2014, we had forward-starting interest-rate swaps with notional amounts totaling \$400 million and \$900 million, respectively, that have been designated as cash flow hedges of the variability of interest payments on a portion of forecasted debt issuances that may result from changes in the benchmark interest rate before the debt is issued. Future issuances of long-term debt could be impacted by increases in interest rates, which could result in higher interest costs. At December 31, 2015, we had derivative liabilities of \$9.9 million related to these interest-rate swaps. At December 31, 2014, we had derivative assets of \$2.3 million and derivative liabilities of \$44.8 million related to these interest-rate swaps.

In January 2016, we entered into forward-starting interest-rate swaps with notional amounts totaling \$1.0 billion for the period of April 2016 through July 2018 and forward-starting interest-rate swaps with notional amounts totaling \$500 million for the period of July 2018 through January 2019 that were designated as cash flow hedges to hedge the variability on our LIBOR-based interest payments.

See Note D of the Notes to Consolidated Financial Statements in this Annual Report for more information on ONEOK Partners' hedging activities.

COUNTERPARTY CREDIT RISK

We assess the creditworthiness of our counterparties on an ongoing basis and require security, including prepayments and other forms of collateral, when appropriate. Certain of our counterparties to our Natural Gas Gathering and Processing segment's natural gas sales, our Natural Gas Liquids segment's marketing activities and our Natural Gas Pipelines segment's storage activities may be impacted by the depressed commodity price environment and could experience financial problems, which could result in nonpayment and/or nonperformance, which could adversely impact our results of operations.

Customer concentration - In 2015, no single customer represented more than 10 percent of our consolidated revenues and only 15 customers individually represented one percent or more of our consolidated revenues.

Natural Gas Gathering and Processing - Our Natural Gas Gathering and Processing segment's customers are primarily large integrated and independent exploration and production companies. We are not typically exposed to material credit risk with exploration and production customers under POP with fee contracts as we receive proceeds from the sale of commodities and remit a portion of those proceeds back to the crude oil and natural gas producers. In 2015, 99 percent of the downstream commodity sales in our Natural Gas Gathering and Processing segment were made to investment-grade customers, as rated by S&P or Moody's, or our comparable internal ratings, or secured by letters of credit or other collateral.

Natural Gas Liquids - Our Natural Gas Liquids segment's customers are primarily NGL and natural gas gathering and processing companies; major and independent crude oil and natural gas production companies; propane distributors; ethanol producers; and petrochemical, refining and NGL marketing companies. We earn fee revenue from NGL and natural gas gathering and processing customers and natural gas liquids pipeline transportation customers. We are not typically exposed to material credit risk on the majority of our exchange services fee revenues, as we purchase NGLs from our gathering and processing customers and deduct our fee from the amounts we remit. We also earn sales revenue on the downstream sales of NGL products. In 2015, more than 80 percent of our commodity sales were made to investment-grade customers, as rated by S&P or Moody's, or our comparable internal ratings, or secured by letters of credit or other collateral. In addition, the majority of our Natural Gas Liquids segment's pipeline tariffs provide us the ability to require security from shippers.

Natural Gas Pipelines - Our Natural Gas Pipelines segment's customers are primarily local natural gas distribution companies, electric-generation facilities, large industrial companies, municipalities, irrigation customers and marketing companies. In 2015, more than 85 percent of our revenues in this segment were from investment-grade customers, as rated by S&P or Moody's, or our comparable internal ratings, or secured by letters of credit or other collateral. In addition, the majority of our Natural Gas Pipeline segment's pipeline tariffs provide us the ability to require security from shippers.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of ONEOK Partners GP, L.L.C. as General Partner of ONEOK Partners, L.P. and to the Unitholders:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, changes in equity and cash flows present fairly, in all material respects, the financial position of ONEOK Partners, L.P. and its subsidiaries (the Partnership) at December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements and on the Partnership's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

/s/ PricewaterhouseCoopers LLP

Tulsa, Oklahoma
February 23, 2016

ONEOK Partners, L.P. and Subsidiaries
CONSOLIDATED STATEMENTS OF INCOME

	Years Ended December 31,		
	2015	**2014**	**2013**
	(*Thousands of dollars, except per unit amounts*)		
Revenues			
Commodity sales	**$ 6,098,343**	$ 10,724,981	$ 10,549,157
Services	**1,662,725**	1,466,684	1,320,116
Total revenues	**7,761,068**	12,191,665	11,869,273
Cost of sales and fuel (exclusive of items shown separately below)	**5,641,052**	10,088,548	10,222,213
Operations and maintenance	**609,123**	599,076	464,633
Depreciation and amortization	**352,196**	291,236	236,743
Impairment of long-lived assets (Note E)	**83,673**	—	—
General taxes	**83,053**	70,581	56,880
Gain (loss) on sale of assets	**6,108**	6,599	11,881
Operating income	**998,079**	1,148,823	900,685
Equity in net earnings from investments (Note M)	**125,300**	117,415	110,517
Impairment of equity investments (Note M)	**(180,583)**	(76,412)	—
Allowance for equity funds used during construction	**2,179**	14,937	30,522
Other income	**126**	5,447	12,870
Other expense	**(4,174)**	(4,299)	(3,039)
Interest expense (net of capitalized interest of $36,572, $54,813 and $56,506, respectively)	**(338,911)**	(281,908)	(236,714)
Income before income taxes	**602,016**	924,003	814,841
Income taxes (Note L)	**(4,144)**	(12,668)	(10,858)
Net income	**597,872**	911,335	803,983
Less: Net income attributable to noncontrolling interests	**8,330**	1,037	357
Net income attributable to ONEOK Partners, L.P.	**$ 589,542**	$ 910,298	$ 803,626
Limited partners' interest in net income:			
Net income attributable to ONEOK Partners, L.P.	**$ 589,542**	$ 910,298	$ 803,626
General partner's interest in net income	**(394,550)**	(344,241)	(275,539)
Limited partners' interest in net income	**$ 194,992**	$ 566,057	$ 528,087
Limited partners' net income per unit, basic and diluted (Note K)	**$ 0.73**	$ 2.33	$ 2.35
Number of units used in computation (*thousands*)	**267,281**	243,306	224,658

See accompanying Notes to Consolidated Financial Statements.

ONEOK Partners, L.P. and Subsidiaries
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31,		
	2015	**2014**	**2013**
	(*Thousands of dollars*)		
Net income	**$ 597,872**	$ 911,335	$ 803,983
Other comprehensive income (loss)			
Unrealized gains (losses) on derivatives	**45,575**	(64,639)	32,141
Realized (gains) losses on derivatives recognized in net income	**(67,034)**	31,653	8,344
Total other comprehensive income (loss)	**(21,459)**	(32,986)	40,485
Comprehensive income	**576,413**	878,349	844,468
Less: Comprehensive income attributable to noncontrolling interests	**8,330**	1,037	357
Comprehensive income attributable to ONEOK Partners, L.P.	**$ 568,083**	$ 877,312	$ 844,111

See accompanying Notes to Consolidated Financial Statements.

ONEOK Partners, L.P. and Subsidiaries
CONSOLIDATED BALANCE SHEETS

	December 31, 2015	December 31, 2014
Assets	(*Thousands of dollars*)	
Current assets		
Cash and cash equivalents	**$ 5,079**	$ 42,530
Accounts receivable, net	**593,448**	735,830
Affiliate receivables	**7,969**	8,553
Natural gas and natural gas liquids in storage	**128,084**	134,134
Commodity imbalances	**38,681**	64,788
Materials and supplies	**76,696**	55,833
Other current assets	**33,207**	44,385
Total current assets	**883,164**	1,086,053
Property, plant and equipment		
Property, plant and equipment	**14,307,546**	13,377,617
Accumulated depreciation and amortization	**2,050,755**	1,842,084
Net property, plant and equipment (Note E)	**12,256,791**	11,535,533
Investments and other assets		
Investments in unconsolidated affiliates (Note M)	**948,221**	1,132,653
Goodwill and intangible assets (Note F)	**824,877**	822,358
Other assets	**14,533**	23,803
Total investments and other assets	**1,787,631**	1,978,814
Total assets	**$ 14,927,586**	$ 14,600,400
Liabilities and equity		
Current liabilities		
Current maturities of long-term debt (Note H)	**$ 107,650**	$ 7,650
Short-term borrowings (Note G)	**546,340**	1,055,296
Accounts payable	**605,431**	874,692
Affiliate payables	**27,137**	36,106
Commodity imbalances	**74,460**	104,650
Accrued interest	**102,615**	91,990
Other current liabilities	**116,667**	165,672
Total current liabilities	**1,580,300**	2,336,056
Long-term debt, excluding current maturities (Note H)	**6,695,312**	6,004,232
Deferred credits and other liabilities	**154,631**	141,337
Commitments and contingencies (Note O)		
Equity (Note I)		
ONEOK Partners, L.P. partners' equity:		
General partner	**231,344**	211,914
Common units: 212,837,980 and 180,826,973 units issued and outstanding at December 31, 2015 and December 31, 2014, respectively	**5,014,952**	4,456,372
Class B units: 72,988,252 units issued and outstanding at December 31, 2015 and December 31, 2014	**1,200,204**	1,374,375
Accumulated other comprehensive loss (Note J)	**(113,282)**	(91,823)
Total ONEOK Partners, L.P. partners' equity	**6,333,218**	5,950,838
Noncontrolling interests in consolidated subsidiaries	**164,125**	167,937
Total equity	**6,497,343**	6,118,775
Total liabilities and equity	**$ 14,927,586**	$ 14,600,400

See accompanying Notes to Consolidated Financial Statements.

ONEOK Partners, L.P. and Subsidiaries
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2015	**2014**	**2013**
	(*Thousands of dollars*)		
Operating activities			
Net income	**$ 597,872**	$ 911,335	$ 803,983
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	**352,196**	291,236	236,743
Impairment charges	**264,256**	76,412	—
Allowance for equity funds used during construction	**(2,179)**	(14,937)	(30,522)
Gain on sale of assets	**(6,108)**	(6,599)	(11,881)
Deferred income taxes	**4,765**	10,832	5,444
Equity in net earnings from investments	**(125,300)**	(117,415)	(110,517)
Distributions received from unconsolidated affiliates	**122,003**	117,912	106,364
Changes in assets and liabilities, net of acquisitions:			
Accounts receivable	**147,767**	373,459	(184,271)
Affiliate receivables	**584**	632	6,907
Natural gas and natural gas liquids in storage	**6,050**	54,152	47,550
Accounts payable	**(199,895)**	(351,470)	187,253
Affiliate payables	**(8,969)**	(11,352)	(28,252)
Commodity imbalances, net	**(4,083)**	(93,234)	(50,373)
Accrued interest	**10,625**	(721)	15,977
Risk-management assets and liabilities	**(34,275)**	36,444	12,109
Other assets and liabilities, net	**(53,329)**	33,134	1,217
Cash provided by operating activities	**1,071,980**	1,309,820	1,007,731
Investing activities			
Capital expenditures (less allowance for equity funds used during construction)	**(1,186,123)**	(1,745,990)	(1,939,326)
Cash paid for acquisitions, net of cash received	**—**	(814,934)	(394,889)
Contributions to unconsolidated affiliates	**(27,540)**	(1,063)	(35,308)
Distributions received from unconsolidated affiliates in excess of cumulative earnings	**33,915**	21,107	31,134
Proceeds from sale of assets	**3,825**	7,817	12,290
Other	**(12,607)**	—	—
Cash used in investing activities	**(1,188,530)**	(2,533,063)	(2,326,099)
Financing activities			
Cash distributions:			
General and limited partners	**(1,230,475)**	(1,052,245)	(909,713)
Noncontrolling interests	**(11,690)**	(549)	(588)
Borrowing (repayment) of short-term borrowings, net	**(508,956)**	1,055,296	—
Issuance of long-term debt, net of discounts	**798,896**	—	1,247,822
Debt financing costs	**(7,676)**	—	(10,246)
Repayment of long-term debt	**(7,650)**	(7,650)	(7,650)
Issuance of common units, net of issuance costs	**1,025,660**	1,113,139	583,929
Contribution from general partner	**20,990**	23,252	12,270
Cash provided by financing activities	**79,099**	1,131,243	915,824
Change in cash and cash equivalents	**(37,451)**	(92,000)	(402,544)
Cash and cash equivalents at beginning of period	**42,530**	134,530	537,074
Cash and cash equivalents at end of period	**$ 5,079**	$ 42,530	$ 134,530
Supplemental cash flow information:			
Cash paid for interest, net of amounts capitalized	**$ 307,036**	$ 271,314	$ 203,072
Cash paid for income taxes	**$ 3,483**	$ 1,336	$ 3,435

See accompanying Notes to Consolidated Financial Statements.

ONEOK Partners, L.P. and Subsidiaries
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

	ONEOK Partners, L.P. Partners' Equity			
	Common Units	Class B Units	General Partner	Common Units
	(*Units*)		(*Thousands of dollars*)	
January 1, 2013	146,827,354	72,988,252	$ 152,513	$ 2,945,051
Net income	—	—	275,539	356,593
Other comprehensive income (loss)	—	—	—	—
Issuance of common units (Note I)	12,180,500	—	—	588,656
Contribution from general partner (Note I)	—	—	12,366	—
Distributions paid (Note I)	—	—	(269,857)	(430,380)
December 31, 2013	159,007,854	72,988,252	170,561	3,459,920
Net income	—	—	344,241	394,503
Other comprehensive income (loss) (Note J)	—	—	—	—
Issuance of common units (Note I)	21,819,119	—	—	1,108,456
Contribution from general partner (Note I)	—	—	23,155	—
Distributions paid (Note I)	—	—	(326,043)	(506,507)
West Texas LPG noncontrolling interest (Note B)	—	—	—	—
December 31, 2014	180,826,973	72,988,252	211,914	4,456,372
Net income	**—**	**—**	**394,550**	**138,520**
Other comprehensive income (loss) (Note J)	**—**	**—**	**—**	**—**
Issuance of common units (Note I)	**32,011,007**	**—**	**—**	**1,023,767**
Contribution from general partner (Note I)	**—**	**—**	**20,990**	**—**
Distributions paid (Note I)	**—**	**—**	**(396,110)**	**(603,722)**
Other	**—**	**—**	**—**	**15**
December 31, 2015	**212,837,980**	**72,988,252**	**$ 231,344**	**$ 5,014,952**

See accompanying Notes to Consolidated Financial Statements.

ONEOK Partners, L.P. and Subsidiaries

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(Continued)

	ONEOK Partners, L.P. Partners' Equity			
	Class B Units	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests in Consolidated Subsidiaries	Total Equity
		(*Thousands of dollars*)		
January 1, 2013	$ 1,460,498	$ (99,322)	$ 4,767	$ 4,463,507
Net income	171,494	—	357	803,983
Other comprehensive income (loss)	—	40,485	—	40,485
Issuance of common units (Note I)	—	—	—	588,656
Contribution from general partner (Note I)	—	—	—	12,366
Distributions paid (Note I)	(209,476)	—	(588)	(910,301)
December 31, 2013	1,422,516	(58,837)	4,536	4,998,696
Net income	171,554	—	1,037	911,335
Other comprehensive income (loss) (Note J)	—	(32,986)	—	(32,986)
Issuance of common units (Note I)	—	—	—	1,108,456
Contribution from general partner (Note I)	—	—	—	23,155
Distributions paid (Note I)	(219,695)	—	(549)	(1,052,794)
West Texas LPG noncontrolling interest (Note B)	—	—	162,913	162,913
December 31, 2014	1,374,375	(91,823)	167,937	6,118,775
Net income	**56,472**	**—**	**8,330**	**597,872**
Other comprehensive income (loss) (Note J)	**—**	**(21,459)**	**—**	**(21,459)**
Issuance of common units (Note I)	**—**	**—**	**—**	**1,023,767**
Contribution from general partner (Note I)	**—**	**—**	**—**	**20,990**
Distributions paid (Note I)	**(230,643)**	**—**	**(11,690)**	**(1,242,165)**
Other	**—**	**—**	**(452)**	**(437)**
December 31, 2015	**$ 1,200,204**	**$ (113,282)**	**$ 164,125**	**$ 6,497,343**

ONEOK PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Nature of Operations - ONEOK Partners, L.P. is a publicly traded master limited partnership, organized under the laws of the state of Delaware, that was formed in 1993. Our equity consists of a 2 percent general partner interest and a 98 percent limited partner interest. Our limited partner interests are represented by our common units, which are listed on the NYSE under the trading symbol "OKS," and our Class B limited partner units. We are managed under the direction of the Board of Directors of our sole general partner, ONEOK Partners GP. ONEOK Partners GP is a wholly owned subsidiary of ONEOK. ONEOK and its subsidiaries owned a 41.2 percent aggregate equity interest in us at December 31, 2015.

Our operations include gathering and processing of natural gas produced from crude oil and natural gas wells. We gather and process natural gas in the Mid-Continent region, which includes the NGL-rich Cana-Woodford Shale, Woodford Shale, Springer Shale, Stack, SCOOP areas of Oklahoma, the Mississippian Lime formation of Oklahoma and Kansas, and the Hugoton and Central Kansas Uplift Basins of Kansas. We also gather and/or process natural gas in two producing basins in the Rocky Mountain region: the Williston Basin, which spans portions of Montana and North Dakota and includes the oil-producing, NGL-rich Bakken Shale and Three Forks formations; and the Powder River Basin of Wyoming, which includes the NGL-rich Frontier, Turner, Sussex and Niobrara Shale formations. The natural gas we gather from wells that supply our Sage Creek plant contains NGL-rich natural gas from the Niobrara Shale area of the Powder River Basin.

Our natural gas liquids assets consist of facilities that gather, fractionate and treat NGLs and store NGL products primarily in Oklahoma, Kansas, Texas, New Mexico and the Rocky Mountain region where we provide nondiscretionary services to producers of NGLs. We own or have an ownership interest in FERC-regulated natural gas liquids gathering and distribution pipelines in Oklahoma, Kansas, Texas, New Mexico, Montana, North Dakota, Wyoming and Colorado, and terminal and storage facilities in Missouri, Nebraska, Iowa and Illinois. We also own FERC-regulated natural gas liquids distribution and refined petroleum products pipelines in Kansas, Missouri, Nebraska, Iowa, Illinois and Indiana that connect our Mid-Continent assets with Midwest markets, including Chicago, Illinois. We own and operate truck- and rail-loading and -unloading facilities that interconnect with our NGL fractionation and pipeline assets.

Our Natural Gas Pipeline segment operates interstate and intrastate natural gas transmission pipelines and natural gas storage facilities. Our FERC-regulated interstate natural gas pipeline assets transport natural gas through pipelines in North Dakota, Minnesota, Wisconsin, Illinois, Indiana, Kentucky, Tennessee, Oklahoma, Texas and New Mexico. Our intrastate natural gas pipeline assets in Oklahoma transport natural gas throughout the state and have access to the major natural gas producing formations, including the Cana-Woodford Shale, Woodford Shale, Springer Shale, Granite Wash, Stack, SCOOP and Mississippian Lime areas. During 2015, we entered into a 50-50 joint venture, Roadrunner, which will transport natural gas from the Permian Basin in West Texas to the Mexican border near El Paso, Texas. The Roadrunner pipeline is currently under construction, with Phase I expected to be completed in the first quarter 2016.

We own underground natural gas storage facilities in Oklahoma and Texas that are connected to our intrastate natural gas pipeline assets. We also have underground natural gas storage facilities in Kansas.

Consolidation - Our consolidated financial statements include the accounts of ONEOK Partners and our subsidiaries over which we have control or are the primary beneficiary. All significant intercompany balances and transactions have been eliminated in consolidation.

Investments in unconsolidated affiliates are accounted for using the equity method if we have the ability to exercise significant influence over operating and financial policies of our investee. Under this method, an investment is carried at its acquisition cost and adjusted each period for contributions made, distributions received and our share of the investee's comprehensive income. For the investments we account for under the equity method, the premium or excess cost over underlying fair value of net assets is referred to as equity-method goodwill. Impairment of equity investments is recorded when the impairments are other than temporary. These amounts are recorded as investments in unconsolidated affiliates on our accompanying Consolidated Balance Sheets. See Note M for disclosures of our unconsolidated affiliates.

Distributions paid to us from our unconsolidated affiliates are classified as operating activities on our Consolidated Statements of Cash Flows until the cumulative distributions exceed our proportionate share of income from the unconsolidated affiliate since the date of our initial investment. The amount of cumulative distributions paid to us that exceeds our cumulative proportionate share of income in each period represents a return of investment and is classified as an investing activity on our Consolidated Statements of Cash Flows.

Use of Estimates - The preparation of our consolidated financial statements and related disclosures in accordance with GAAP requires us to make estimates and assumptions with respect to values or conditions that cannot be known with certainty that affect the reported amount of assets and liabilities, and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements. These estimates and assumptions also affect the reported amounts of revenue and expenses during the reporting period. Items that may be estimated include, but are not limited to, the economic useful life of assets, fair value of assets, liabilities and equity-method investments, provisions for uncollectible accounts receivable, unbilled revenues and cost of goods sold, expenses for services received but for which no invoice has been received, the results of litigation and various other recorded or disclosed amounts.

We evaluate these estimates on an ongoing basis using historical experience, consultation with experts and other methods we consider reasonable based on the particular circumstances. Nevertheless, actual results may differ significantly from the estimates. Any effects on our financial position or results of operations from revisions to these estimates are recorded in the period when the facts that give rise to the revision become known.

Fair Value Measurements - We define fair value as the price that would be received from the sale of an asset or the transfer of a liability in an orderly transaction between market participants at the measurement date. We use market and income approaches to determine the fair value of our assets and liabilities and consider the markets in which the transactions are executed. We measure the fair value of a group of financial assets and liabilities consistent with how a market participant would price the net risk exposure at the measurement date.

While many of the contracts in our portfolio are executed in liquid markets where price transparency exists, some contracts are executed in markets for which market prices may exist, but the market may be relatively inactive. This results in limited price transparency that requires management's judgment and assumptions to estimate fair values. For certain transactions, we utilize modeling techniques using NYMEX-settled pricing data and implied forward LIBOR curves. Inputs into our fair value estimates include commodity-exchange prices, over-the-counter quotes, historical correlations of pricing data, data obtained from third-party pricing services and LIBOR and other liquid money-market instrument rates. We validate our valuation inputs with third-party information and settlement prices from other sources, where available.

In addition, as prescribed by the income approach, we compute the fair value of our derivative portfolio by discounting the projected future cash flows from our derivative assets and liabilities to present value using interest-rate yields to calculate present-value discount factors derived from LIBOR, Eurodollar futures and interest-rate swaps. We also take into consideration the potential impact on market prices of liquidating positions in an orderly manner over a reasonable period of time under current market conditions. We consider current market data in evaluating counterparties', as well as our own, nonperformance risk, net of collateral, by using specific and sector bond yields and monitoring the credit default swap markets. Although we use our best estimates to determine the fair value of the derivative contracts we have executed, the ultimate market prices realized could differ from our estimates, and the differences could be material.

The fair value of our forward-starting interest-rate swaps are determined using financial models that incorporate the implied forward LIBOR yield curve for the same period as the future interest swap settlements.

<u>Fair Value Hierarchy</u> - At each balance sheet date, we utilize a fair value hierarchy to classify fair value amounts recognized or disclosed in our financial statements based on the observability of inputs used to estimate such fair value. The levels of the hierarchy are described below:

- Level 1 - fair value measurements are based on unadjusted quoted prices for identical securities in active markets including NYMEX-settled prices. These balances are comprised predominantly of exchange-traded derivative contracts for natural gas and crude oil.
- Level 2 - fair value measurements are based on significant observable pricing inputs, such as NYMEX-settled prices for natural gas and crude oil and financial models that utilize implied forward LIBOR yield curves for interest-rate swaps.
- Level 3 - fair value measurements are based on inputs that may include one or more unobservable inputs, including internally developed natural gas basis and NGL price curves that incorporate observable and unobservable market data from broker quotes, third-party pricing services, market volatilities derived from the most recent NYMEX close spot prices and forward LIBOR curves, and adjustments for the credit risk of our counterparties. We corroborate the data on which our fair value estimates are based using our market knowledge of recent transactions, analysis of historical correlations and validation with independent broker quotes. These balances categorized as Level 3 are comprised of derivatives for natural gas and NGLs. We do not believe that our Level 3 fair value estimates have a material impact

on our results of operations, as the majority of our derivatives are accounted for as hedges for which ineffectiveness has not been material.

Determining the appropriate classification of our fair value measurements within the fair value hierarchy requires management's judgment regarding the degree to which market data is observable or corroborated by observable market data. We categorize derivatives for which fair value is determined using multiple inputs within a single level, based on the lowest level input that is significant to the fair value measurement in its entirety.

See Note C for discussion of our fair value measurements.

Cash and Cash Equivalents - Cash equivalents consist of highly liquid investments, which are readily convertible into cash and have original maturities of three months or less.

Revenue Recognition - Our reportable segments recognize revenue when services are rendered or product is delivered. Our Natural Gas Gathering and Processing segment records revenues when natural gas is processed in or transported through our facilities. Our Natural Gas Liquids segment records revenues based upon contracted services and actual volumes exchanged or stored under service agreements in the period services are provided. A portion of our revenues for our Natural Gas Pipelines segment and our Natural Gas Liquids segment are recognized based upon contracted capacity and contracted volumes transported and stored under service agreements in the period services are provided. We disaggregate revenue on the Consolidated Statements of Income as follows:

- *Commodity sales* - Commodity sales represent the sale of NGLs, condensate and residue natural gas. The commodities are primarily obtained as compensation for or related to providing services. Commodity sales are recognized upon delivery or title transfer to the customer, when revenue recognition criteria are met.
- *Service revenue* - Service revenue represents the fees generated from the performance of our services listed above.

We enter into a variety of contract types that provide commodity sales and service revenue. We provide services primarily under the following types of contracts:

- *Fee based* - Under fee-based arrangements, we receive a fee or fees for one or more of the following services: gathering, compression, processing, transmission and storage of natural gas; and gathering, transportation, fractionation, exchange and storage of NGLs. The revenue we earn from these arrangements generally is directly related to the volume of natural gas and NGLs that flow through our systems and facilities, and is not normally directly dependent on commodity prices. However, to the extent a sustained decline in commodity prices results in a decline in volumes, our revenues from these arrangements would be reduced. In addition, many of our arrangements provide for fixed fee, minimum volume or firm demand charges. Fee-based arrangements are reported as service revenue on the Consolidated Statements of Income.
- *Percent-of-proceeds* - Under POP arrangements in our Natural Gas Gathering and Processing segment, we gather and process natural gas on behalf of producers; sell the resulting residue natural gas, condensate and NGLs at market prices; and remit to producers an agreed-upon percentage of the net proceeds resulting from the sale. The agreed-upon percentage remitted to the producer is reported as cost of sales on the Consolidated Statements of Income. In other cases, instead of remitting cash payments to the producer, we deliver an agreed-upon percentage of the commodities to the producer (take-in-kind agreements) and sell the volumes we retain to third parties. Typically, our POP arrangements also include a fee-based component.

In many cases, we provide services under contracts that contain a combination of the arrangements described above. When fees are charged (in addition to commodities received) under POP with fee contracts, we record such fees as service revenue on the Consolidated Statements of Income. The terms of our contracts vary based on natural gas quality conditions, the competitive environment when the contracts are signed and customer requirements.

Cost of Sales and Fuel - Cost of sales and fuel primarily includes (i) the cost of purchased commodities, including NGLs, natural gas and condensate, (ii) fees incurred for third-party transportation, fractionation and storage of commodities, and (iii) fuel and power costs incurred to operate our own facilities that gather, process, transport and store commodities.

Operations and Maintenance - Operations and maintenance primarily includes (i) payroll and benefit costs, (ii) third-party costs for operations, maintenance and integrity management, regulatory compliance and environmental and safety, and (iii) other business related service costs.

Accounts Receivable - Accounts receivable represent valid claims against nonaffiliated customers for products sold or services rendered, net of allowances for doubtful accounts. We assess the creditworthiness of our counterparties on an ongoing basis and require security, including prepayments and other forms of collateral, when appropriate. Outstanding customer receivables are reviewed regularly for possible nonpayment indicators, and allowances for doubtful accounts are recorded based upon management's estimate of collectability at each balance sheet date. At December 31, 2015 and 2014, our allowance for doubtful accounts was not material.

Inventory - The values of current natural gas and NGLs in storage are determined using the lower of weighted-average cost or market method. Noncurrent natural gas and NGLs are classified as property and valued at cost. Materials and supplies are valued at average cost.

Commodity Imbalances - Commodity imbalances represent amounts payable or receivable for NGL exchange contracts and natural gas pipeline imbalances and are valued at market prices. Under the majority of our NGL exchange agreements, we physically receive volumes of unfractionated NGLs, including the risk of loss and legal title to such volumes, from the exchange counterparty. In turn, we deliver NGL products back to the customer and charge them gathering and fractionation fees. To the extent that the volumes we receive under such agreements differ from those we deliver, we record a net exchange receivable or payable position with the counterparties. These net exchange receivables and payables are settled with movements of NGL products rather than with cash. Natural gas pipeline imbalances are settled in cash or in-kind, subject to the terms of the pipelines' tariffs or by agreement.

Derivatives and Risk Management - We utilize derivatives to reduce our market-risk exposure to commodity price and interest-rate fluctuations and to achieve more predictable cash flows. We record all derivative instruments at fair value, with the exception of normal purchases and normal sales transactions that are expected to result in physical delivery. Commodity price and interest-rate volatility may have a significant impact on the fair value of derivative instruments as of a given date. The accounting for changes in the fair value of a derivative instrument depends on whether it has been designated and qualifies as part of a hedging relationship and, if so, the reason for holding it.

The table below summarizes the various ways in which we account for our derivative instruments and the impact on our consolidated financial statements:

	Recognition and Measurement	
Accounting Treatment	**Balance Sheet**	**Income Statement**
Normal purchases and normal sales	- Fair value not recorded	- Change in fair value not recognized in earnings
Mark-to-market	- Recorded at fair value	- Change in fair value recognized in earnings
Cash flow hedge	- Recorded at fair value	- Ineffective portion of the gain or loss on the derivative instrument is recognized in earnings
	- Effective portion of the gain or loss on the derivative instrument is reported initially as a component of accumulated other comprehensive income (loss)	- Effective portion of the gain or loss on the derivative instrument is reclassified out of accumulated other comprehensive income (loss) into earnings when the forecasted transaction affects earnings
Fair value hedge	- Recorded at fair value	- The gain or loss on the derivative instrument is recognized in earnings
	- Change in fair value of the hedged item is recorded as an adjustment to book value	- Change in fair value of the hedged item is recognized in earnings

To reduce our exposure to fluctuations in natural gas, NGLs and condensate prices, we periodically enter into futures, forward purchases and sales, options or swap transactions in order to hedge anticipated purchases and sales of natural gas, NGLs and condensate. Interest-rate swaps are used from time to time to manage interest-rate risk. Under certain conditions, we designate our derivative instruments as a hedge of exposure to changes in fair values or cash flows. We formally document all relationships between hedging instruments and hedged items, as well as risk-management objectives and strategies for undertaking various hedge transactions, and methods for assessing and testing correlation and hedge ineffectiveness. We specifically identify the forecasted transaction that has been designated as the hedged item in a cash flow hedge relationship. We assess the effectiveness of hedging relationships quarterly by performing an effectiveness analysis on our fair value and cash flow hedging relationships to determine whether the hedge relationships are highly effective on a retrospective and prospective basis. We also document our normal purchases and normal sales transactions that we expect to result in physical delivery and that we elect to exempt from derivative accounting treatment.

The realized revenues and purchase costs of our derivative instruments not considered held for trading purposes and derivatives that qualify as normal purchases or normal sales that are expected to result in physical delivery are reported on a gross basis.

Cash flows from futures, forwards and swaps that are accounted for as hedges are included in the same category as the cash flows from the related hedged items in our Consolidated Statements of Cash Flows.

See Notes C and D for more discussion of our fair value measurements and risk-management and hedging activities using derivatives.

Property, Plant and Equipment - Our properties are stated at cost, including AFUDC. Generally, the cost of regulated property retired or sold, plus removal costs, less salvage, is charged to accumulated depreciation. Gains and losses from sales or transfers of nonregulated properties or an entire operating unit or system of our regulated properties are recognized in income. Maintenance and repairs are charged directly to expense.

The interest portion of AFUDC represents the cost of borrowed funds used to finance construction activities. We capitalize interest costs during the construction or upgrade of qualifying assets. Capitalized interest is recorded as a reduction to interest expense. The equity portion of AFUDC represents the capitalization of the estimated average cost of equity used during the construction of major projects and is recorded in the cost of our regulated properties and as a credit to the allowance for equity funds used during construction.

Our properties are depreciated using the straight-line method over their estimated useful lives. Generally, we apply composite depreciation rates to functional groups of property having similar economic circumstances. We periodically conduct depreciation studies to assess the economic lives of our assets. For our regulated assets, these depreciation studies are completed as a part of our rate proceedings or tariff filings, and the changes in economic lives, if applicable, are implemented prospectively when the new rates are billed. For our nonregulated assets, if it is determined that the estimated economic life changes, the changes are made prospectively. Changes in the estimated economic lives of our property, plant and equipment could have a material effect on our financial position or results of operations.

Property, plant and equipment on our Consolidated Balance Sheets includes construction work in process for capital projects that have not yet been placed in service and therefore are not being depreciated. Assets are transferred out of construction work in process when they are substantially complete and ready for their intended use.

See Note E for disclosures of our property, plant and equipment.

Impairment of Goodwill and Long-Lived Assets, Including Intangible Assets - We assess our goodwill for impairment at least annually on July 1, unless events or changes in circumstances indicate an impairment may have occurred before that time. At July 1, 2015, due to the current commodity price environment, we elected to perform a quantitative assessment, or Step 1 analysis, to test our goodwill for impairment. The assessment included our commodity price assumptions, expected contractual terms, anticipated operating costs and volume estimates. Our goodwill impairment analysis performed as of July 1, 2015, did not result in an impairment charge nor did our analysis reflect any reporting units at risk. In each reporting unit, the fair value substantially exceeded the carrying value. At December 31, 2015, we performed a qualitative review given the decline in commodity prices and our common unit price since our assessment as of July 1, 2015, and determined that no event has occurred indicating that the implied fair value of each of our reporting units is less than the carrying value of its net assets.

As part of our impairment test, we may first assess qualitative factors (including macroeconomic conditions, industry and market considerations, cost factors and overall financial performance) to determine whether it is more likely than not that the fair value of each of our reporting units is less than its carrying amount. If further testing is necessary or a quantitative test is elected, we perform a two-step impairment test for goodwill. In the first step, an initial assessment is made by comparing the fair value of a reporting unit with its book value, including goodwill. If the fair value is less than the book value, an impairment is indicated, and we must perform a second test to measure the amount of the impairment. In the second test, we calculate the implied fair value of the goodwill by deducting the fair value of all tangible and intangible net assets of the reporting unit from the fair value determined in step one of the assessment. If the carrying value of the goodwill exceeds the implied fair value of the goodwill, we will record an impairment charge.

To estimate the fair value of our reporting units, we use two generally accepted valuation approaches, an income approach and a market approach, using assumptions consistent with a market participant's perspective. Under the income approach, we use anticipated cash flows over a period of years plus a terminal value and discount these amounts to their present value using appropriate discount rates. Under the market approach, we apply EBITDA multiples to forecasted EBITDA. The multiples used are consistent with historical asset transactions. The forecasted cash flows are based on average forecasted cash flows for a reporting unit over a period of years.

We assess our long-lived assets, including intangible assets with finite useful lives, for impairment whenever events or changes in circumstances indicate that an asset's carrying amount may not be recoverable. An impairment is indicated if the carrying amount of a long-lived asset exceeds the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If an impairment is indicated, we record an impairment loss equal to the difference between the carrying value and the fair value of the long-lived asset.

For the investments we account for under the equity method, the impairment test considers whether the fair value of the equity investment as a whole, not the underlying net assets, has declined and whether that decline is other than temporary. Therefore, we periodically reevaluate the amount at which we carry our equity-method investments to determine whether current events or circumstances warrant adjustments to our carrying value.

See Notes E, F and M for our long-lived assets, goodwill and intangible assets and investments in unconsolidated affiliates disclosures.

Regulation - Our intrastate natural gas transmission and natural gas liquids pipelines are subject to the rate regulation and accounting requirements of the OCC, KCC, RRC and various municipalities in Texas. Our interstate natural gas and natural gas liquids pipelines are subject to regulation by the FERC. In Kansas and Texas, natural gas storage may be regulated by the state and the FERC for certain types of services. Accordingly, portions of our Natural Gas Liquids and Natural Gas Pipelines segments follow the accounting and reporting guidance for regulated operations. During the rate-making process for certain of our assets, regulatory authorities set the framework for what we can charge customers for our services and establish the manner that our costs are accounted for, including allowing us to defer recognition of certain costs and permitting recovery of the amounts through rates over time as opposed to expensing such costs as incurred. Certain examples of types of regulatory guidance include costs for fuel and losses, acquisition costs, contributions in aid of construction, charges for depreciation, and gains or losses on disposition of assets. This allows us to stabilize rates over time rather than passing such costs on to the customer for immediate recovery. Actions by regulatory authorities could have an effect on the amount recovered from rate payers. Any difference in the amount recoverable and the amount deferred is recorded as income or expense at the time of the regulatory action. A write-off of regulatory assets and costs not recovered may be required if all or a portion of the regulated operations have rates that are no longer:

- established by independent, third-party regulators;
- designed to recover the specific entity's costs of providing regulated services; and
- set at levels that will recover our costs when considering the demand and competition for our services.

At December 31, 2015 and 2014, we recorded regulatory assets of approximately $5.8 million and $6.1 million, respectively, which are currently being recovered and are expected to be recovered from our customers. Regulatory assets are being recovered as a result of approved rate proceedings over varying time periods up to 40 years. These assets are reflected in other assets on our Consolidated Balance Sheets.

Income Taxes - We are not a taxable entity for federal income tax purposes. As such, we do not directly pay federal income tax. Our taxable income or loss, which may vary substantially from the net income or loss reported in our Consolidated Statements of Income, is included in the federal income tax returns of each partner. The aggregate difference in the basis of our net assets for financial and income tax purposes cannot be readily determined, as we do not have access to all information about each partner's tax attributes related to us.

Our corporate subsidiaries are required to pay federal and state income taxes. Deferred income taxes are provided for the difference between the financial statement and income tax basis of assets and liabilities and carryforward items based on income tax laws and rates existing at the time the temporary differences are expected to reverse. Generally, the effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date of the rate change. For regulated companies, the effect on deferred tax assets and liabilities of a change in tax rates is recorded as regulatory assets and regulatory liabilities in the period that includes the enactment date, if, as a result of an action by a regulator, it is probable that the effect of the change in tax rates will be recovered from or returned to customers through future rates.

We utilize a more-likely-than-not recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position that is taken or expected to be taken in a tax return. We reflect penalties and interest as part of income tax expense as they become applicable for tax provisions that do not meet the more-likely-than-not recognition threshold and measurement attribute. During 2015, 2014 and 2013, our tax positions did not require an establishment of a material reserve.

We file numerous consolidated and separate income tax returns with federal tax authorities of the United States along with the tax authorities of several states. There are no United States federal audits or statute waivers at this time. See Note L for additional discussion of income taxes.

Asset Retirement Obligations - Asset retirement obligations represent legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset. Certain of our natural gas gathering and processing facilities, and our natural gas liquids and pipeline facilities are subject to agreements or regulations that give rise to our asset retirement obligations for removal or other disposition costs associated with retiring the assets in place upon the discontinued use of the assets. We recognize the fair value of a liability for an asset retirement obligation in the period when it is incurred if a reasonable estimate of the fair value can be made. We are not able to estimate reasonably the fair value of the asset retirement obligations for portions of our assets, primarily certain pipeline assets, because the settlement dates are indeterminable given our expected continued use of the assets with proper maintenance. We expect our pipeline assets, for which we are unable to estimate reasonably the fair value of the asset retirement obligation, will continue in operation as long as supply and demand for natural gas and natural gas liquids exists. Based on the widespread use of natural gas for heating and cooking activities for residential users and electric-power generation for commercial users, as well as use of natural gas liquids by the petrochemical industry, we expect supply and demand to exist for the foreseeable future.

For our assets that we are able to make an estimate, the fair value of the liability is added to the carrying amount of the associated asset, and this additional carrying amount is depreciated over the life of the asset. The liability is accreted at the end of each period through charges to operating expense. If the obligation is settled for an amount other than the carrying amount of the liability, we will recognize a gain or loss on settlement. The depreciation and accretion expense are immaterial to our consolidated financial statements.

In accordance with long-standing regulatory treatment, we collect, through rates, the estimated costs of removal on certain regulated properties through depreciation expense, with a corresponding credit to accumulated depreciation and amortization. These removal costs collected through rates include legal and nonlegal removal obligations; however, the amounts collected in excess of the asset removal costs incurred are accounted for as a regulatory liability for financial reporting purposes. Historically, the regulatory authorities that have jurisdiction over our regulated operations have not required us to quantify this amount; rather, these costs are addressed prospectively in depreciation rates and are set in each general rate order. We have made an estimate of our regulatory liability using current rates since the last general rate order in each of our jurisdictions; however, for financial reporting purposes, significant uncertainty exists regarding the ultimate disposition of this regulatory liability pending, among other issues, clarification of regulatory intent. We continue to monitor regulatory requirements, and the liability may be adjusted as more information is obtained.

Contingencies - Our accounting for contingencies covers a variety of business activities, including contingencies for legal and environmental exposures. We accrue these contingencies when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered and an amount can be estimated reasonably. We expense legal fees as incurred and base our legal liability estimates on currently available facts and our estimates of the ultimate outcome or resolution. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than completion of a remediation feasibility study. Recoveries of environmental remediation costs from other parties are recorded as assets when their receipt is deemed probable. Our expenditures for environmental evaluation, mitigation, remediation and compliance to date have not been significant in relation to our financial position or results of operations, and our expenditures related to environmental matters had no material effect on earnings or cash flows during 2015, 2014 and 2013. Actual results may differ from our estimates resulting in an impact, positive or negative, on earnings. See Note O for additional discussion of contingencies.

Recently Issued Accounting Standards Update - In November 2015, the FASB issued ASU 2015-17, “Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes,” which simplifies the presentation and requires that deferred tax liabilities and assets be classified as noncurrent in the balance sheet. This guidance is effective for public companies for annual periods beginning after December 15, 2016, and interim periods within those annual periods. Earlier application is permitted as of the beginning of an interim or annual reporting period. We elected to adopt this guidance beginning in the fourth quarter 2015. Prior periods were not retrospectively adjusted. The impact of adopting this guidance was not material. See Note L for additional disclosures.

In March 2015, the FASB issued ASU 2015-03, “Interest - Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs,” which requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. In August 2015, the FASB issued ASU 2015-15, “Interest - Imputation of Interest (Subtopic 835-30): Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements - Amendments to SEC Paragraphs Pursuant to Staff Announcement at June 18, 2015 EITF Meeting," which amended the SEC paragraphs of ASC Subtopic 835-30 to include the language from the SEC Staff Announcement indicating that the SEC would not object to presenting deferred debt issuance costs related to line-of-credit agreements as assets and subsequently amortizing the deferred debt issuance costs ratably over the term of the agreement. This guidance is effective for public companies for fiscal years beginning after December 15, 2015, with early adoption permitted. We elected to adopt this guidance beginning in the second quarter 2015. Retrospective adjustment of prior periods presented was required. Therefore, the December 31, 2014, balance sheet was recast to reclassify $34.1 million of debt issuance costs from other assets to long-term debt. See Note H for additional disclosures.

In April 2014, the FASB issued ASU 2014-08, "Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360): Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity," which alters the definition of a discontinued operation to include only asset disposals that represent a strategic shift with a major effect on an entity's operations and financial results. The amendment also requires more extensive disclosures about a discontinued operation's assets, liabilities, income, expenses and cash flows. We adopted this guidance beginning in the first quarter 2015, and it could impact us in the future if we dispose of any individually significant components.

In January 2016, the FASB issued ASU 2016-01, "Financial Instruments-Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities," which requires all equity investments other than those accounted for using the equity method of accounting or those that result in consolidation of the investee to be measured at fair value with changes in fair value recognized in net income, eliminates the available-for-sale classification for equity securities with readily determinable fair values and eliminates the cost method for equity investments without readily determinable fair values. Additionally, this guidance eliminates the requirement to disclose the methods and significant assumptions used to estimate the fair value of financial instruments carried at amortized cost and requires the use of the exit price when measuring the fair value of such instruments for disclosure purposes. This guidance will be effective for public business entities in fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. Early adoption is only permitted for certain portions of the ASU. We expect to adopt this guidance in the first quarter 2018 and are evaluating the impact on us.

In September 2015, the FASB issued ASU 2015-16, "Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments," which requires that an acquirer recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. The amendment also requires the acquirer to record the income statement effects of changes to provisional amounts in the financial statements in the period in which the adjustments occurred. This guidance is effective for public companies for fiscal years beginning after December 15, 2015. We expect to adopt this guidance in the first quarter 2016, and it could impact us in the future if we complete any acquisitions with subsequent measurement period adjustments.

In July 2015, the FASB issued ASU 2015-11, "Inventory (Topic 330): Simplifying the Measurement of Inventory," which requires that inventory, excluding inventory measured using last-in, first-out (LIFO) or the retail inventory method, be measured at the lower of cost or net realizable value. This guidance will be effective for public companies for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years. We expect to adopt this guidance in the first quarter 2017, and we are evaluating the impact on us.

In April 2015, the FASB issued ASU 2015-05, "Intangibles—Goodwill and Other—Internal-Use Software (Subtopic 350-40): Customer's Accounting for Fees Paid in a Cloud Computing Arrangement," which clarifies whether a cloud computing arrangement includes a software license. If it does, the customer should account for the software license element of the arrangement consistent with the acquisition of other software licenses; if not, the customer should not account for the arrangement as a service contract. This guidance is effective for public companies for fiscal years beginning after December 15, 2015. We expect to adopt this guidance in the first quarter 2016, and we do not expect it to materially impact us.

In February 2015, the FASB issued ASU 2015-02, "Consolidation (Topic 810): Amendments to the Consolidation Analysis," which eliminates the presumption that a general partner should consolidate a limited partnership. It also modifies the evaluation of whether limited partnerships are variable interest entities or voting interest entities and adds requirements that limited partnerships must meet to qualify as voting interest entities. This guidance is effective for public companies for fiscal years beginning after December 15, 2015. We expect to adopt this guidance in the first quarter 2016, and we are evaluating the impact on us.

In August 2014, the FASB issued ASU 2014-15, "Presentation of Financial Statements- Going Concern (Subtopic 205-40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern," which provides guidance on determining when and how to disclose going-concern uncertainties in the financial statements. The new standard requires management to perform interim and annual assessments of an entity's ability to continue as a going concern within one year of the date the financial statements are issued. An entity must provide certain disclosures if conditions or events raise substantial doubt about the entity's ability to continue as a going concern. The standard applies to all entities and is effective for annual periods ending after December 15, 2016, and interim periods thereafter, with early adoption permitted. We expect to adopt this guidance beginning in the fourth quarter 2016, and we do not expect it to materially impact us.

In May 2014, the FASB issued ASU 2014-09, "Revenue from Contracts with Customers (Topic 606)," which outlines the principles an entity must apply to measure and recognize revenue for entities that enter into contracts to provide goods or services to their customers. The core principle is that an entity should recognize revenue at an amount that reflects the consideration to which the entity expects to be entitled in exchange for transferring goods or services to a customer. The amendment also requires more extensive disaggregated revenue disclosures in interim and annual financial statements. In August 2015, the FASB issued ASU 2015-14, "Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date," that deferred the effective date of ASU 2014-09 by one year. This update is now effective for interim and annual periods that begin after December 15, 2017, with either retrospective application for all periods presented or retrospective application with a cumulative effect adjustment. We expect to adopt this guidance beginning in the first quarter 2018, and we are evaluating the impact on us.

B. ACQUISITIONS

West Texas LPG - In November 2014, we completed the acquisition of an 80 percent interest in WTLPG and a 100 percent interest in the Mesquite Pipeline for approximately $800 million from affiliates of Chevron Corporation, and we became the operator of both pipelines. Financing to close this transaction came from available cash on hand and borrowings under our existing commercial paper program.

The acquisition consists of approximately 2,600 miles of natural gas liquids gathering pipelines extending from the Permian Basin in southeastern New Mexico to East Texas and Mont Belvieu, Texas. The acquired pipelines access NGL supply from producers actively developing the Delaware, Midland and Central Basins in the Permian Basin, in addition to the Barnett Shale, East Texas and north Louisiana regions. The pipeline system increased our natural gas liquids gathering system by approximately 60 percent to nearly 7,100 miles of natural gas liquids gathering pipelines and added approximately 285,000 barrels per day of NGL capacity. These assets provide us with additional fee-based earnings and our natural gas liquids infrastructure with access to a new natural gas liquids supply basin.

We accounted for the West Texas LPG acquisition as a business combination which, among other things, requires assets acquired and liabilities assumed to be measured at their acquisition-date fair values.

Our Consolidated Balance Sheet as of December 31, 2015, reflects the final purchase price allocation. Adjustments to the preliminary purchase price allocation reported in Note B in the Notes to the Consolidated Financial Statements in our 2014 Annual Report were not material, and prior period financial statements have not been recast.

The final purchase price allocation and assessment of the fair value of the assets acquired as of the acquisition date were as follows:

		(*Thousands of dollars*)
Cash	$	13,839
Accounts receivable		9,132
Other current assets		3,369
Property, plant and equipment		
Regulated		812,716
Nonregulated		157,643
Total property, plant and equipment		970,359
Total fair value of assets acquired		996,699
Accounts payable		(8,621)
Other liabilities		(10,867)
Total fair value of liabilities acquired		(19,488)
Less: Fair value of noncontrolling interest		(162,438)
Net assets acquired		814,773
Less: Cash received		(13,839)
Net cash paid for acquisition	$	800,934

Beginning November 29, 2014, the results of operations for West Texas LPG are included in our Natural Gas Liquids segment. We consolidate WTLPG and have recorded noncontrolling interests in consolidated subsidiaries on our Consolidated Statements of Income and Consolidated Balance Sheets to recognize the portion of WTLPG that we do not own. The portion of the assets and liabilities of WTLPG acquired attributable to noncontrolling interests was accounted for as noncash activity. The fair value of the noncontrolling interest of WTLPG was estimated by applying a market approach.

Revenues and earnings related to West Texas LPG have been included within the Consolidated Statements of Income since the acquisition date. Supplemental pro forma revenue and earnings reflecting this acquisition as if it had occurred as of January 1, 2013, are not materially different from the information presented in the accompanying Consolidated Statements of Income and are, therefore, not presented.

The limited partnership agreement of WTLPG provides that distributions to the partners are to be made on a pro rata basis according to each partner’s ownership interest. Cash distributions to the partners are currently declared and paid by WTLPG each calendar quarter. Any changes to, or suspension of, the cash distributions from WTLPG requires the approval of a minimum of 90 percent of the ownership interest and a minimum of two general partners of WTLPG. Cash distributions are equal to 100 percent of distributable cash as defined in the limited partnership agreement of WTLPG.

Sage Creek - On September 30, 2013, we completed for $305 million the acquisition of certain natural gas gathering and processing, and natural gas liquids facilities in Converse and Campbell counties, Wyoming, in the NGL-rich Niobrara Shale area of the Powder River Basin. The Sage Creek acquisition consists primarily of a 50 MMcf/d natural gas processing facility, the Sage Creek plant, and related natural gas gathering and natural gas liquids infrastructure. Included in the acquisition were supply contracts providing for long-term acreage dedications from producers in the area, which are structured with POP and fee-based contractual terms. The acquisition is complementary to our existing natural gas liquids assets and provides additional natural gas gathering and processing and natural gas liquids gathering capacity in the region.

This acquisition was accounted for as a business combination. The excess of cost over those fair values was recorded as goodwill. The purchase price and assessment of the fair value of the assets acquired were as follows:

	Natural Gas Gathering and Processing	Natural Gas Liquids	Total
Property, plant and equipment		*(Thousands of dollars)*	
Gathering pipelines and related equipment	$ 41,129	$ 18,045	$ 59,174
Processing and fractionation and related equipment	50,595	—	50,595
General plant and other	120	—	120
Intangible assets	40,000	63,000	103,000
Identifiable assets acquired	131,844	81,045	212,889
Goodwill	20,000	72,000	92,000
Total purchase price	$ 151,844	$ 153,045	$ 304,889

Identifiable intangible assets recognized in the Sage Creek acquisition are primarily related to natural gas gathering and processing and natural gas liquids gathering and fractionation supply contracts with acreage dedications and customer relationships. The basis for determining the value of these intangible assets is the estimated future net cash flows to be derived from acquired supply contracts and customer relationships, which are offset with appropriate charges for the use of contributory assets and discounted using a risk-adjusted discount rate. Those intangible assets are being amortized on a straight-line basis over an initial 20-year period for our Natural Gas Gathering and Processing segment and an initial 30-year period for our Natural Gas Liquids segment, which represents a portion of the term over which the customer contracts and relationships are expected to contribute to our cash flows.

Revenues and earnings related to the Sage Creek acquisition are included within the Consolidated Statements of Income since the acquisition date. Supplemental pro forma revenue and earnings reflecting this acquisition as if it had occurred as of January 1, 2012, are not materially different from the information presented in the accompanying Consolidated Statements of Income and are, therefore, not presented.

Maysville - In December 2013, we acquired the remaining 30 percent undivided interest in the Maysville, Oklahoma, natural gas processing facility for $90 million. Beginning December 1, 2013, the results of operations for our 100 percent interest are included in our Natural Gas Gathering and Processing segment.

C. FAIR VALUE MEASUREMENTS

Recurring Fair Value Measurements - The following tables set forth our recurring fair value measurements for the periods indicated:

	December 31, 2015					
	Level 1	Level 2	Level 3	Total - Gross	Netting (a)	Total - Net (b)
			(Thousands of dollars)			
Derivative assets						
Commodity contracts						
Financial contracts	**$ 38,921**	**$ —**	**$ 7,253**	**$ 46,174**	**$ (42,414)**	**$ 3,760**
Physical contracts	**—**	**—**	**3,591**	**3,591**	**—**	**3,591**
Total derivative assets	**$ 38,921**	**$ —**	**$ 10,844**	**$ 49,765**	**$ (42,414)**	**$ 7,351**
Derivative liabilities						
Commodity contracts						
Financial contracts	**$ (4,513)**	**$ —**	**$ (3,513)**	**$ (8,026)**	**$ 8,026**	**$ —**
Interest-rate contracts	**—**	**(9,936)**	**—**	**(9,936)**	**—**	**(9,936)**
Total derivative liabilities	**$ (4,513)**	**$ (9,936)**	**$ (3,513)**	**$ (17,962)**	**$ 8,026**	**$ (9,936)**

(a) - Our derivative assets and liabilities are presented in our Consolidated Balance Sheets on a net basis. We net derivative assets and liabilities when a legally enforceable master-netting arrangement exists between the counterparty to a derivative contract and us. At December 31, 2015, we had $34.4 million of cash held from various counterparties and no cash collateral posted.
(b) - Included in other current assets or other current liabilities in our Consolidated Balance Sheets.

	December 31, 2014					
	Level 1	Level 2	Level 3	Total - Gross	Netting (a)	Total - Net (b)
	(*Thousands of dollars*)					
Derivative assets						
Commodity contracts						
Financial contracts	$ 42,880	$ —	$ 354	$ 43,234	$ (25,979)	$ 17,255
Physical contracts	—	—	9,922	9,922	—	9,922
Interest-rate contracts	—	2,288	—	2,288	—	2,288
Total derivative assets	$ 42,880	$ 2,288	$ 10,276	$ 55,444	$ (25,979)	$ 29,465
Derivative liabilities						
Commodity contracts						
Financial contracts	$ (169)	$ —	$ (968)	$ (1,137)	$ 1,137	$ —
Physical contracts	—	—	(23)	(23)	—	(23)
Interest-rate contracts	—	(44,843)	—	(44,843)	—	(44,843)
Total derivative liabilities	$ (169)	$ (44,843)	$ (991)	$ (46,003)	$ 1,137	$ (44,866)

(a) - Our derivative assets and liabilities are presented in our Consolidated Balance Sheets on a net basis. We net derivative assets and liabilities when a legally enforceable master-netting arrangement exists between the counterparty to a derivative contract and us. At December 31, 2014, we had $24.8 million of cash held from various counterparties and no cash collateral posted.
(b) - Included in other current assets, other assets or other current liabilities in our Consolidated Balance Sheets.

The following table sets forth a reconciliation of our Level 3 fair value measurements for the periods indicated:

	Years Ended December 31,	
Derivative Assets (Liabilities)	**2015**	**2014**
	(*Thousands of dollars*)	
Net assets (liabilities) at beginning of period	**$ 9,285**	$ (782)
Total realized/unrealized gains (losses):		
Included in earnings (a)	**216**	(927)
Included in other comprehensive income (loss)	**(2,170)**	7,260
Settlements	**—**	3,734
Net assets (liabilities) at end of period	**$ 7,331**	$ 9,285

(a) - Included in commodity sales revenues in our Consolidated Statements of Income.

Realized/unrealized gains (losses) include the realization of our derivative contracts through maturity. During the years ended December 31, 2015 and 2014, gains or losses included in earnings attributable to the change in unrealized gains or losses relating to assets and liabilities still held at the end of each reporting period were not material.

We recognize transfers into and out of the levels in the fair value hierarchy as of the end of each reporting period. During the years ended December 31, 2015 and 2014, there were no transfers between levels.

Other Financial Instruments - The approximate fair value of cash and cash equivalents, accounts receivable, accounts payable and short-term borrowings is equal to book value, due to the short-term nature of these items. Our cash and cash equivalents are comprised of bank and money market accounts and are classified as Level 1. Our short-term borrowings are classified as Level 2 since the estimated fair value of the short-term borrowings can be determined using information available in the commercial paper market.

The estimated fair value of the aggregate of our senior notes outstanding, including current maturities, was $6.2 billion and $6.4 billion at December 31, 2015 and 2014, respectively. The book value of the aggregate of our senior notes outstanding, including current maturities, was $6.8 billion and $6.0 billion at December 31, 2015 and 2014, respectively. The estimated fair value of the aggregate of our senior notes outstanding was determined using quoted market prices for similar issues with similar terms and maturities. The estimated fair value of our long-term debt is classified as Level 2.

During 2015 and 2014, we recorded noncash impairment charges primarily related to our equity investments in the dry natural gas area of the Powder River Basin. The valuation of these investments required use of significant unobservable inputs. We used an income approach to estimate the fair value of our investments. Our discounted cash flow analysis included the following inputs that are not readily available: a discount rate reflective of our cost of capital and estimated contract rates, volumes, operating and maintenance costs and capital expenditures. The estimated fair value of these investments is classified as Level 3. See Note M for additional information about our equity investments and the impairment charges.

D. RISK-MANAGEMENT AND HEDGING ACTIVITIES USING DERIVATIVES

Risk-Management Activities - We are sensitive to changes in natural gas, crude oil and NGL prices, principally as a result of contractual terms under which these commodities are processed, purchased and sold. We use physical-forward purchases and sales and financial derivatives to secure a certain price for a portion of our natural gas, condensate and NGL products; to reduce our exposure to interest-rate fluctuations; and to achieve more predictable cash flows. We follow established policies and procedures to assess risk and approve, monitor and report our risk-management activities. We have not used these instruments for trading purposes. We are also subject to the risk of interest-rate fluctuation in the normal course of business.

Commodity price risk - Commodity price risk refers to the risk of loss in cash flows and future earnings arising from adverse changes in the price of natural gas, NGLs and condensate. We use the following commodity derivative instruments to mitigate the near-term commodity price risk associated with a portion of the forecasted sales of these commodities:

- Futures contracts - Standardized contracts to purchase or sell natural gas and crude oil for future delivery or settlement under the provisions of exchange regulations;
- Forward contracts - Nonstandardized commitments between two parties to purchase or sell natural gas, crude oil or NGLs for future physical delivery. These contracts are typically nontransferable and can only be canceled with the consent of both parties; and
- Swaps - Exchange of one or more payments based on the value of one or more commodities. These instruments transfer the financial risk associated with a future change in value between the counterparties of the transaction, without also conveying ownership interest in the asset or liability.

We may also use other instruments including options or collars to mitigate commodity price risk. Options are contractual agreements that give the holder the right, but not the obligation, to buy or sell a fixed quantity of a commodity, at a fixed price, within a specified period of time. Options may either be standardized and exchange traded or customized and nonexchange traded. A collar is a combination of a purchased put option and a sold call option, which places a floor and a ceiling price for commodity sales being hedged.

In our Natural Gas Gathering and Processing segment, we are exposed to commodity price risk as a result of receiving commodities as a portion of our compensation for services associated with our POP with fee contracts. We also are exposed to basis risk between the various production and market locations where we receive and sell commodities. As part of our hedging strategy, we use the previously described commodity derivative financial instruments and physical-forward contracts to reduce the impact of price fluctuations related to natural gas, NGLs and condensate.

In our Natural Gas Liquids segment, we are exposed to location price differential risk, primarily as a result of the relative value of NGL purchases at one location and sales at another location. We are also exposed to commodity price risk resulting from the relative values of the various NGL products to each other, NGLs in storage and the relative value of NGLs to natural gas. We utilize physical-forward contracts and commodity derivative financial instruments to reduce the impact of price fluctuations related to NGLs.

In our Natural Gas Pipelines segment, we are exposed to commodity price risk because our intrastate and interstate natural gas pipelines retain natural gas from our customers for operations or as part of our fee for services provided. When the amount of natural gas consumed in operations by these pipelines differs from the amount provided by our customers, our pipelines must buy or sell natural gas, or store or use natural gas from inventory, which can expose us to commodity price risk depending on the regulatory treatment for this activity. To the extent that commodity price risk in our Natural Gas Pipelines segment is not mitigated by fuel cost-recovery mechanisms, we use physical-forward sales or purchases to reduce the impact of price fluctuations related to natural gas. At December 31, 2015 and 2014, there were no financial derivative instruments with respect to our natural gas pipeline operations.

Interest-rate risk - We manage interest-rate risk through the use of fixed-rate debt, floating-rate debt and interest-rate swaps. Interest-rate swaps are agreements to exchange interest payments at some future point based on specified notional amounts. At December 31, 2015 and 2014, we had forward-starting interest-rate swaps with notional amounts totaling $400 million and $900 million, respectively, that have been designated as cash flow hedges of the variability of interest payments on a portion of forecasted debt issuances that may result from changes in the benchmark interest rate before the debt is issued. Upon our debt issuance in March 2015, we settled $500 million of our interest-rate swaps and realized a loss of $55.1 million, which is included in accumulated other comprehensive loss and will be amortized to interest expense over the term of the related debt.

At December 31, 2015, our remaining interest-rate swaps with notional amounts totaling $400 million have settlement dates of less than 12 months.

In January 2016, we entered into forward-starting interest-rate swaps with notional amounts totaling $1.0 billion for the period of April 2016 through July 2018 and forward-starting interest-rate swaps with notional amounts totaling $500 million for the period of July 2018 through January 2019 that were designated as cash flow hedges to hedge the variability on our LIBOR-based interest payments.

Fair Values of Derivative Instruments - The following table sets forth the fair values of our derivative instruments for the periods indicated:

	December 31, 2015		December 31, 2014	
	Assets (a)	**(Liabilities) (a)**	**Assets (b)**	**(Liabilities) (b)**
	(*Thousands of dollars*)			
Derivatives designated as hedging instruments				
Commodity contracts				
Financial contracts	**$ 39,255**	**$ (1,440)**	$ 43,234	$ (1,137)
Physical contracts	**3,591**	**—**	9,922	—
Interest-rate contracts	**—**	**(9,936)**	2,288	(44,843)
Total derivatives designated as hedging instruments	**42,846**	**(11,376)**	55,444	(45,980)
Derivatives not designated as hedging instruments				
Commodity contracts				
Financial contracts	**6,919**	**(6,586)**	—	—
Physical contracts	**—**	**—**	—	(23)
Total derivatives not designated as hedging instruments	**6,919**	**(6,586)**	—	(23)
Total derivatives	**$ 49,765**	**$ (17,962)**	$ 55,444	$ (46,003)

(a) - Included on a net basis in other current assets or other current liabilities in our Consolidated Balance Sheets.
(b) - Included on a net basis in other current assets, other assets or other current liabilities in our Consolidated Balance Sheets.

Notional Quantities for Derivative Instruments - The following table sets forth the notional quantities for derivative instruments held for the periods indicated:

		December 31, 2015		December 31, 2014	
	Contract Type	**Purchased/ Payor**	**Sold/ Receiver**	**Purchased/ Payor**	**Sold/ Receiver**
Derivatives designated as hedging instruments:					
Cash flow hedges					
Fixed price					
-Natural gas (*Bcf*)	Futures and swaps	**—**	**(27.1)**	—	(41.2)
-Crude oil and NGLs (*MMBbl*)	Futures, forwards and swaps	**—**	**(2.3)**	—	(0.5)
Basis					
-Natural gas (*Bcf*)	Futures and swaps	**—**	**(27.1)**	—	(41.2)
Interest-rate contracts (*Millions of dollars*)	Forward-starting swaps	**$ 400.0**	**$ —**	$ 900.0	$ —
Derivatives not designated as hedging instruments:					
Fixed price					
-Crude oil and NGLs (*MMBbl*)	Futures, forwards and swaps	**0.6**	**(0.6)**	—	—

These notional amounts are used to summarize the volume of financial instruments; however, they do not reflect the extent to which the positions offset one another and consequently do not reflect our actual exposure to market or credit risk.

Cash Flow Hedges - At December 31, 2015, our Consolidated Balance Sheet reflected a net loss of $113.3 million in accumulated other comprehensive loss. The portion of accumulated other comprehensive loss attributable to our commodity derivative financial instruments is an unrealized gain of $41.5 million, which will be realized within the next 12 months as the forecasted transactions affect earnings and if commodity prices remain at the current levels. The amount deferred in accumulated other comprehensive loss attributable to our settled interest-rate swaps is a loss of $141.7 million, which will be recognized over the life of the long-term, fixed-rate debt, including losses of $15.7 million will be reclassified into earnings during the next 12 months as the hedged items affect earnings. The remaining amounts in accumulated other comprehensive loss are attributable primarily to forward-starting interest-rate swaps with future settlement dates, which will be amortized to interest expense over the life of long-term, fixed-rate debt upon issuance of the debt.

The following table sets forth the unrealized effect of cash flow hedges recognized in other comprehensive income (loss) for the periods indicated:

	Years Ended December 31,		
Derivatives in Cash Flow Hedging Relationships	**2015**	**2014**	**2013**
		(Thousands of dollars)	
Commodity contracts	**$ 70,065**	$ 32,354	$ (14,475)
Interest-rate contracts	**(22,565)**	(96,993)	46,616
Total unrealized gain (loss) recognized in other comprehensive income (loss) on derivatives(effective portion)	**$ 47,500**	$ (64,639)	$ 32,141

Unrealized gain (loss) related to our equity-method investments are not included in the table above and were not material.

The following table sets forth the effect of cash flow hedges in our Consolidated Statements of Income for the periods indicated:

		Years Ended December 31,		
Derivatives in Cash Flow Hedging Relationships	**Location of Gain (Loss) Reclassified from Accumulated Other Comprehensive Loss into Net Income (Effective Portion)**	**2015**	**2014**	**2013**
			(Thousands of dollars)	
Commodity contracts	Commodity sales revenues	**$ 81,089**	$ (21,052)	$ 1,689
Interest-rate contracts	Interest expense	**(14,055)**	(10,601)	(10,033)
Total gain (loss) reclassified from accumulated other comprehensive income (loss) into net income on derivatives (effective portion)		**$ 67,034**	$ (31,653)	$ (8,344)

Ineffectiveness related to our cash flow hedges was not material for the years ended December 31, 2015, 2014 and 2013. In the event that it becomes probable that a forecasted transaction will not occur, we would discontinue cash flow hedge treatment, which would affect earnings. There were no gains or losses due to the discontinuance of cash flow hedge treatment during 2015, 2014 and 2013.

Credit Risk - We monitor the creditworthiness of our counterparties and compliance with policies and limits established by our Risk Oversight and Strategy Committee. We maintain credit policies with regard to our counterparties that we believe minimize overall credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit ratings, bond yields and credit default swap rates), collateral requirements under certain circumstances and the use of standardized master-netting agreements that allow us to net the positive and negative exposures associated with a single counterparty. We have counterparties whose credit is not rated, and for those customers, we use internally developed credit ratings.

From time to time, we may enter into financial derivative instruments that contain provisions that require us to maintain an investment-grade credit rating from S&P and/or Moody's. If our credit ratings on our senior unsecured long-term debt were to decline below investment grade, the counterparties to the derivative instruments could request collateralization on derivative instruments in net liability positions. There were no financial derivative instruments with contingent features related to credit risk as of December 31, 2015.

The counterparties to our derivative contracts consist primarily of major energy companies, financial institutions and commercial and industrial end users. This concentration of counterparties may affect our overall exposure to credit risk, either positively or negatively, in that the counterparties may be affected similarly by changes in economic, regulatory or other conditions. Based on our policies, exposures, credit and other reserves, we do not anticipate a material adverse effect on our financial position or results of operations as a result of counterparty nonperformance.

At December 31, 2015, the net credit exposure from our derivative assets is primarily with investment-grade companies in the financial services sector.

E. PROPERTY, PLANT AND EQUIPMENT

The following table sets forth our property, plant and equipment by property type, for the periods indicated:

	Estimated Useful Lives (Years)	December 31, 2015	December 31, 2014
		(*Thousands of dollars*)	
Nonregulated			
Gathering pipelines and related equipment	5 to 40	**$ 2,961,388**	$ 2,449,343
Processing and fractionation and related equipment	3 to 40	**3,627,062**	2,880,572
Storage and related equipment	5 to 54	**456,437**	478,276
Transmission pipelines and related equipment	5 to 54	**416,391**	518,585
General plant and other	2 to 60	**186,358**	142,276
Construction work in process	—	**690,179**	1,233,808
Regulated			
Storage and related equipment	5 to 54	**76,468**	115,799
Natural gas transmission pipelines and related equipment	5 to 77	**1,507,220**	1,478,035
Natural gas liquids transmission pipelines and related equipment	5 to 88	**4,208,121**	3,822,799
General plant and other	2 to 54	**94,461**	63,424
Construction work in process	—	**83,461**	194,700
Property, plant and equipment		**14,307,546**	13,377,617
Accumulated depreciation and amortization - nonregulated		**(1,219,435)**	(1,123,261)
Accumulated depreciation and amortization - regulated		**(831,320)**	(718,823)
Net property, plant and equipment		**$ 12,256,791**	$ 11,535,533

The average depreciation rates for our regulated property are set forth, by segment, in the following table for the periods indicated:

	Years Ended December 31,		
	2015	2014	2013
Natural Gas Liquids	**1.9%**	2.0%	2.0%
Natural Gas Pipelines	**2.1%**	2.1%	2.2%

We incurred liabilities for construction work in process that had not been paid at December 31, 2015, 2014 and 2013, of $115.7 million, $187.2 million and $226.7 million, respectively. Such amounts are not included in capital expenditures (less allowance for equity funds used during construction) on the Consolidated Statements of Cash Flows.

Impairment Charges - Crude oil and natural gas producers have primarily focused their development efforts on crude oil and NGL-rich supply basins rather than in areas with dry natural gas production, such as the coal-bed methane production areas in the Powder River Basin. The reduced development activities and production declines in the dry natural gas area of the Powder River Basin have resulted in lower natural gas volumes available to be gathered. Due to the continued and greater than expected decline in volumes gathered in the coal-bed methane area of the Powder River Basin, we evaluated our assets and investments in this area for impairment and determined that we will cease operations of our wholly owned coal-bed methane natural gas gathering system in 2016. We recorded $63.5 million of noncash impairment charges on these long-lived assets in the fourth quarter 2015 in our Natural Gas Gathering and Processing segment.

In addition, we recorded noncash impairment charges of approximately $20.2 million for previously idled assets in the Natural Gas Gathering and Processing and Natural Gas Liquids segments in the fourth quarter 2015, as our expectation for future use of these assets changed.

F. GOODWILL AND INTANGIBLE ASSETS

Goodwill - The following table sets forth our goodwill, by segment, for the periods indicated:

	December 31, 2015	December 31, 2014
	(*Thousands of dollars*)	
Natural Gas Gathering and Processing	**$ 112,141**	$ 112,141
Natural Gas Liquids	**247,566**	247,566
Natural Gas Pipelines	**129,011**	129,011
Total goodwill	**$ 488,718**	$ 488,718

Intangible Assets - Our intangible assets relate primarily to contracts acquired through acquisitions in our Natural Gas Gathering and Processing and Natural Gas Liquids segments, which are being amortized over periods of 20 to 40 years. Amortization expense for intangible assets for 2015, 2014 and 2013 was $11.9 million, $11.8 million and $8.7 million, respectively, and the aggregate amortization expense for each of the next five years is estimated to be approximately $11.9 million. The following table reflects the gross carrying amount and accumulated amortization of intangible assets for the periods presented:

	December 31, 2015	December 31, 2014
	(*Thousands of dollars*)	
Gross intangible assets	**$ 426,068**	$ 411,650
Accumulated amortization	**(89,909)**	(78,010)
Net intangible assets	**$ 336,159**	$ 333,640

G. SHORT-TERM BORROWINGS

Partnership Credit Agreement - In January 2016, we extended the term of our Partnership Credit Agreement by one year to January 2020. Our Partnership Credit Agreement is a $2.4 billion revolving credit facility and includes a $100 million sublimit for the issuance of standby letters of credit and a $150 million swingline sublimit. Our Partnership Credit Agreement is available for general partnership purposes. During the first quarter 2015, we increased the size of our Partnership Credit Agreement to $2.4 billion from $1.7 billion by exercising our option to increase the capacity of the facility through increased commitments from existing lenders and a commitment from one new lender.

We had $14 million of letters of credit issued at December 31, 2015 and 2014, $300.0 million of borrowings outstanding and approximately $1.8 billion capacity available at December 31, 2015, and no borrowings outstanding at December 31, 2014, under our Partnership Credit Agreement. The interest rate on our borrowings at December 31, 2015, was 1.60 percent.

Our Partnership Credit Agreement contains provisions for an applicable margin rate and an annual facility fee, both of which adjust with changes in our credit rating. Under the terms of the Partnership Credit Agreement, based on our current credit ratings, borrowings, if any, will accrue at LIBOR plus 117.5 basis points, and the annual facility fee is 20 basis points. Our Partnership Credit Agreement is guaranteed fully and unconditionally by the Intermediate Partnership. Borrowings under our Partnership Credit Agreement are nonrecourse to ONEOK.

Our Partnership Credit Agreement contains certain financial, operational and legal covenants. Among other things, these covenants include maintaining a ratio of indebtedness to adjusted EBITDA (EBITDA, as defined in our Partnership Credit Agreement, adjusted for all noncash charges and increased for projected EBITDA from certain lender-approved capital expansion projects) of no more than 5.0 to 1. If we consummate one or more acquisitions in which the aggregate purchase price is $25 million or more, the allowable ratio of indebtedness to adjusted EBITDA will increase to 5.5 to 1 for the quarter in which the acquisition was completed and the two following quarters. As a result of the West Texas LPG acquisition we completed in the fourth quarter 2014, the allowable ratio of indebtedness to adjusted EBITDA increased to 5.5 to 1 through the second quarter 2015. If we were to breach certain covenants in our Partnership Credit Agreement, amounts outstanding under our Partnership Credit Agreement, if any, may become due and payable immediately. At December 31, 2015, our ratio of indebtedness to adjusted EBITDA was 4.4 to 1, and we were in compliance with all covenants under our Partnership Credit Agreement.

Neither we nor ONEOK guarantees the debt or other similar commitments of unaffiliated parties. ONEOK does not guarantee the debt, commercial paper or other similar commitments of ONEOK Partners, and ONEOK Partners does not guarantee the debt or other similar commitments of ONEOK.

Commercial Paper Program - During the first quarter 2015, we increased the size of our commercial paper program to $2.4 billion from $1.7 billion. Amounts outstanding under our commercial paper program reduce the borrowing capacity under our Partnership Credit Agreement.

At December 31, 2015 and 2014, we had $246.3 million and $1.1 billion of commercial paper outstanding with weighted-average interest rates of 1.23 percent and 0.54 percent, respectively.

H. LONG-TERM DEBT

All notes are senior unsecured obligations, ranking equally in right of payment with all of our existing and future unsecured senior indebtedness. The following table sets forth our long-term debt for the periods indicated:

	December 31, 2015	December 31, 2014
	(*Thousands of dollars*)	
ONEOK Partners		
$650,000 at 3.25% due 2016	**$ 650,000**	$ 650,000
$450,000 at 6.15% due 2016	**450,000**	450,000
$400,000 at 2.0% due 2017	**400,000**	400,000
$425,000 at 3.2% due 2018	**425,000**	425,000
$500,000 at 8.625% due 2019	**500,000**	500,000
$300,000 at 3.8% due 2020	**300,000**	—
$900,000 at 3.375 % due 2022	**900,000**	900,000
$425,000 at 5.0 % due 2023	**425,000**	425,000
$500,000 at 4.9 % due 2025	**500,000**	—
$600,000 at 6.65% due 2036	**600,000**	600,000
$600,000 at 6.85% due 2037	**600,000**	600,000
$650,000 at 6.125% due 2041	**650,000**	650,000
$400,000 at 6.2% due 2043	**400,000**	400,000
Guardian Pipeline		
Average 7.88% due 2022	**51,907**	59,557
Total long-term notes payable	**6,851,907**	6,059,557
Unamortized debt issuance costs and discounts	**(48,945)**	(47,675)
Current maturities	**(107,650)**	(7,650)
Long-term debt	**$ 6,695,312**	$ 6,004,232

The aggregate maturities of long-term debt outstanding as of December 31, 2015, for the years 2016 through 2020 are shown below:

	ONEOK Partners	Guardian Pipeline	Total
		(*Millions of dollars*)	
2016	$ 1,100.0	$ 7.7	$ 1,107.7
2017	$ 400.0	$ 7.7	$ 407.7
2018	$ 425.0	$ 7.7	$ 432.7
2019	$ 500.0	$ 7.7	$ 507.7
2020	$ 300.0	$ 7.7	$ 307.7

Debt issuances and maturities - In January 2016, we entered into the $1.0 billion senior unsecured delayed-draw Term Loan Agreement with a syndicate of banks, which may be drawn by April 7, 2016. The Term Loan Agreement is intended to effectively refinance $1.0 billion of our $650 million, 3.25 percent senior notes, which matured February 1, 2016, and our $450 million, 6.15 percent senior notes due October 1, 2016. The Term Loan Agreement matures in January 2019 and bears interest at LIBOR plus a margin that is based on the credit ratings assigned to the Company's senior, unsecured, long-term indebtedness. Based on our current applicable credit rating, borrowings on the Term Loan Agreement will accrue at LIBOR plus 130.0 basis points. The Term Loan Agreement contains an option, which may be exercised up to two times, to extend the term of the loan, in each case, for an additional one-year term, subject to approval of the banks. The Term Loan Agreement provides an option to prepay, without penalty or premium, the amount outstanding, or any portion thereof. At December 31, 2015, $1.0 billion of our senior notes due in 2016 have been reflected as long-term debt in our Consolidated Balance Sheet, as we have the intent and ability to refinance the debt, and the remaining $100.0 million is reflected in current maturities of long-term debt.

In March 2015, we completed an underwritten public offering of $800 million of senior notes, consisting of $300 million, 3.8 percent senior notes due 2020, and $500 million, 4.9 percent senior notes due 2025. The net proceeds, after deducting underwriting discounts, commissions and offering expenses, were approximately $792.3 million. We used the proceeds to repay amounts outstanding under our commercial paper program and for general partnership purposes.

In September 2013, we completed an underwritten public offering of $1.25 billion of senior notes, consisting of $425 million, 3.2 percent senior notes due 2018, $425 million, 5.0 percent senior notes due 2023 and $400 million, 6.2 percent senior notes due 2043. A portion of the net proceeds from the offering of approximately $1.24 billion was used to repay amounts outstanding under our commercial paper program, and the balance was used for general partnership purposes, including but not limited to capital expenditures and acquisitions.

Debt covenants - Our Term Loan Agreement contains substantially the same covenants as our Partnership Credit Agreement.

Our senior notes are governed by an indenture, dated as of September 25, 2006, between us and Wells Fargo Bank, N.A., the trustee, as supplemented. The indenture does not limit the aggregate principal amount of debt securities that may be issued and provides that debt securities may be issued from time to time in one or more additional series. The indenture contains covenants including, among other provisions, limitations on our ability to place liens on our property or assets and to sell and lease back our property. The indenture includes an event of default upon acceleration of other indebtedness of $100 million or more. Such events of default would entitle the trustee or the holders of 25 percent in aggregate principal amount of any of our outstanding senior notes to declare those notes immediately due and payable in full.

We may redeem our 6.15 percent senior notes due 2016 and our senior notes due 2019, 2036 and 2037, in whole or in part, at any time prior to their maturity at a redemption price equal to the principal amount, plus accrued and unpaid interest and a make-whole premium. The redemption price will never be less than 100 percent of the principal amount of the respective note plus accrued and unpaid interest to the redemption date. We may redeem our senior notes due 2017 and our senior notes due 2022 at par starting one month and three months, respectively, before their maturity dates. We may redeem our senior notes due 2041 at a redemption price equal to the principal amount, plus accrued and unpaid interest, starting six months before its maturity date. Prior to that date, we may redeem these notes, in whole or in part, at a redemption price equal to the principal amount, plus accrued and unpaid interest and a make-whole premium. We may redeem our senior notes due 2018, 2020, 2023, 2025, and 2043 at par, plus accrued and unpaid interest to the redemption date, starting one month, one month, three months, three months, and six months, respectively, before their maturity dates. Prior to these dates, we may redeem these notes, in whole or in part, at a redemption price equal to the principal amount, plus accrued and unpaid interest and a make-whole premium. The redemption price will never be less than 100 percent of the principal amount of the respective note plus accrued and unpaid interest to the redemption date.

Our senior notes are senior unsecured obligations, ranking equally in right of payment with all of our existing and future unsecured senior indebtedness, and are structurally subordinate to any of the existing and future debt and other liabilities of any nonguarantor subsidiaries.

ONEOK Partners Debt Guarantee - Our senior notes are guaranteed fully and unconditionally on a senior unsecured basis by the Intermediate Partnership. The guarantee ranks equally in right of payment to all of the Intermediate Partnership's existing and future unsecured senior indebtedness. See Note R for additional information on the guarantee. Our long-term debt is nonrecourse to our general partner.

Guardian Pipeline Senior Notes - These senior notes were issued under a master shelf agreement dated November 8, 2001, with certain financial institutions. Principal payments are due quarterly through 2022. Guardian Pipeline's senior notes contain financial covenants that require the maintenance of certain financial ratios as defined in the master shelf agreement based on Guardian Pipeline's financial position and results of operations. Upon any breach of these covenants, all amounts outstanding under the master shelf agreement may become due and payable immediately. At December 31, 2015, Guardian Pipeline was in compliance with its financial covenants.

Other - We amortize premiums, discounts and expenses incurred in connection with the issuance of long-term debt consistent with the terms of the respective debt instrument.

I. EQUITY

ONEOK - ONEOK and its affiliates owned all of the Class B units, 41.3 million common units and the entire 2 percent general partner interest in us, which together constituted a 41.2 percent ownership interest in us at December 31, 2015.

Equity Issuances - In August 2015, we completed a private placement of 21.5 million common units at a price of $30.17 per unit with ONEOK. Additionally, we completed a concurrent sale of approximately 3.3 million common units at a price of $30.17 per unit to funds managed by Kayne Anderson Capital Advisors in a registered direct offering, which were issued through our existing "at-the-market" equity program. The combined offerings generated net cash proceeds of approximately $749 million. In conjunction with these issuances, ONEOK Partners GP contributed approximately $15.3 million in order to maintain its 2 percent general partner interest in us. We used the proceeds for general partnership purposes, including capital expenditures and repayment of commercial paper borrowings.

We have an "at-the-market" equity program for the offer and sale from time to time of our common units, up to an aggregate amount of $650 million. The program allows us to offer and sell our common units at prices we deem appropriate through a sales agent. Sales of common units are made by means of ordinary brokers' transactions on the NYSE, in block transactions or as otherwise agreed to between us and the sales agent. We are under no obligation to offer and sell common units under the program. At December 31, 2015, we had approximately $138 million of registered common units available for issuance through our "at-the-market" equity program.

During the year ended December 31, 2015, we sold 10.5 million common units through our "at-the-market" equity program, including the units sold to funds managed by Kayne Anderson Capital Advisors in the offering discussed above. The net proceeds, including ONEOK Partners GP's contribution to maintain its 2 percent general partner interest in us, were approximately $381.6 million, which were used for general partnership purposes, including repayment of commercial paper borrowings.

As a result of these transactions, ONEOK's aggregate ownership interest in us increased to 41.2 percent at December 31, 2015, from 37.8 percent at December 31, 2014.

In May 2014, we completed an underwritten public offering of 13.9 million common units at a public offering price of $52.94 per common unit, generating net proceeds of approximately $714.5 million. In conjunction with this issuance, ONEOK Partners GP contributed approximately $15.0 million in order to maintain its 2 percent general partner interest in us. We used the proceeds to repay commercial paper, fund our capital expenditures and for general partnership purposes.

During the year ended December 31, 2014, we sold 7.9 million common units through our "at-the-market" equity program. The net proceeds, including ONEOK Partners GP's contribution to maintain its 2 percent general partner interest in us, were approximately $402.1 million, which were used for general partnership purposes.

In August 2013, we completed an underwritten public offering of 11.5 million common units at a public offering price of $49.61 per common unit, generating net proceeds of approximately $553.4 million. In conjunction with this issuance, ONEOK Partners GP contributed approximately $11.6 million in order to maintain its 2 percent general partner interest in us. We used a portion of the proceeds from our August 2013 equity issuance to repay amounts outstanding under our commercial paper program, and the balance was used for general partnership purposes.

During the year ended December 31, 2013, we sold 681,000 common units through our "at-the-market" equity program. The net proceeds, including ONEOK Partners GP's contribution to maintain its 2 percent general partner interest in us, were approximately $36.1 million, which were used for general partnership purposes.

Partnership Agreement - Available cash, as defined in our Partnership Agreement generally will be distributed to our general partner and limited partners according to their partnership percentages of 2 percent and 98 percent, respectively. Our general partner's percentage interest in quarterly distributions is increased after certain specified target levels are met during the quarter. Under the incentive distribution provisions, as set forth in our Partnership Agreement, our general partner receives:

- 15 percent of amounts distributed in excess of $0.3025 per unit;
- 25 percent of amounts distributed in excess of $0.3575 per unit; and
- 50 percent of amounts distributed in excess of $0.4675 per unit.

Cash Distributions - The following table sets forth the quarterly cash distribution declared and paid on each of our common and Class B units during the periods indicated:

Declared for Quarter Ending	Distribution Per Unit	Date Declared	Date Paid
December 31, 2015	$ 0.790	January 21, 2016	February 12, 2016
September 30, 2015	$ 0.790	October 21, 2015	November 13, 2015
June 30, 2015	$ 0.790	July 23, 2015	August 14, 2015
March 31, 2015	$ 0.790	April 16, 2015	May 15, 2015
December 31, 2014	$ 0.790	January 15, 2015	February 13, 2015
September 30, 2014	$ 0.775	October 23, 2014	November 14, 2014
June 30, 2014	$ 0.760	July 25, 2014	August 14, 2014
March 31, 2014	$ 0.745	April 18, 2014	May 15, 2014
December 31, 2013	$ 0.730	January 16, 2014	February 14, 2014
September 30, 2013	$ 0.725	October 23, 2013	November 14, 2013
June 30, 2013	$ 0.720	July 25, 2013	August 15, 2013
March 31, 2013	$ 0.715	April 18, 2013	May 15, 2013
December 31, 2012	$ 0.710	January 17, 2013	February 14, 2013

The following table shows our distributions paid during the periods indicated:

	Years Ended December 31,		
	2015	**2014**	**2013**
	(*Thousands, except per unit amounts*)		
Distribution per unit	**$ 3.16**	$ 3.01	$ 2.87
General partner distributions	**$ 24,610**	$ 21,044	$ 18,193
Incentive distributions	**371,500**	304,999	251,664
Distributions to general partner	**396,110**	326,043	269,857
Limited partner distributions to ONEOK	**310,230**	279,292	266,302
Limited partner distributions to other unitholders	**524,135**	446,910	373,554
Total distributions paid	**$ 1,230,475**	$ 1,052,245	$ 909,713

Distributions are declared and paid within 45 days of the completion of each quarter. The following table shows our distributions declared for the periods indicated:

	Years Ended December 31,		
	2015	**2014**	**2013**
	(*Thousands, except per unit amounts*)		
Distribution per unit	**$ 3.16**	$ 3.07	$ 2.89
General partner distributions	**$ 25,356**	$ 22,109	$ 18,625
Incentive distributions	**382,759**	326,022	259,466
Distributions to general partner	**408,115**	348,131	278,091
Limited partner distributions to ONEOK	**327,250**	284,860	268,157
Limited partner distributions to other unitholders	**532,405**	472,466	384,988
Total distributions declared	**$ 1,267,770**	$ 1,105,457	$ 931,236

Our Class B limited partner units are entitled to receive increased quarterly distributions equal to 110 percent of the distributions paid with respect to our common units. ONEOK, as the sole holder of our Class B limited partner units, has waived its right to receive the increased quarterly distributions on the Class B units. ONEOK retains the option to withdraw its waiver of increased distributions on Class B units at any time by giving us no less than 90 days advance notice. Any such withdrawal of the waiver will be effective with respect to any distribution on the Class B units declared or paid on or after the 90 days following delivery of the notice. The Class B units are eligible to convert into common units on a one-for-one basis at ONEOK's option.

If our common unitholders vote at any time to remove ONEOK or its affiliates as our general partner, quarterly distributions payable on the Class B limited partner units would increase to 123.5 percent of the distributions payable with respect to the common units, and distributions payable upon liquidation of the Class B limited partner units would increase to 123.5 percent of the distributions payable with respect to the common units.

Our income is allocated to the general partner and the limited partners in accordance with their respective partnership percentages, after giving effect to any priority income allocations for incentive distributions that are allocated to the general partner.

Noncontrolling Interest - In November 2014, we completed the acquisition of an 80 percent interest in the WTLPG. We consolidate WTLPG and have recorded noncontrolling interests in consolidated subsidiaries on our consolidated financial statements to recognize the portion of WTLPG that we do not own. Prior to November 2014, our noncontrolling interests in consolidated subsidiaries were not material.

J. ACCUMULATED OTHER COMPREHENSIVE LOSS

The following table sets forth the balance in accumulated other comprehensive income (loss) for the periods indicated:

		Accumulated Other Comprehensive Loss (a)
		(*Thousands of dollars*)
January 1, 2014	$	(58,837)
Other comprehensive income (loss) before reclassifications		(64,639)
Amounts reclassified from accumulated other comprehensive income (loss)		31,653
Net current-period other comprehensive income (loss) attributable to ONEOK Partners		(32,986)
December 31, 2014		(91,823)
Other comprehensive income (loss) before reclassifications		**45,575**
Amounts reclassified from accumulated other comprehensive income (loss)		**(67,034)**
Net current-period other comprehensive income (loss) attributable to ONEOK Partners		**(21,459)**
December 31, 2015	**$**	**(113,282)**

(a) All amounts are attributable to unrealized gains (losses) in risk-management assets/liabilities.

The following table sets forth the effect of reclassifications from accumulated other comprehensive income (loss) in our Consolidated Statements of Income for the periods indicated:

Details about Accumulated Other Comprehensive Income (Loss) Components	Year Ended December 31, 2015	2014	2013	Affected Line Item in the Consolidated Statements of Income
	(*Thousands of dollars*)			
Unrealized (gains) losses on risk-management assets/liabilities				
Commodity contracts	**$ (81,089)**	$ 21,052	$ (1,689)	Commodity sales revenues
Interest-rate contracts	**14,055**	10,601	10,033	Interest expense
Total reclassifications for the period attributable to ONEOK Partners	**$ (67,034)**	$ 31,653	$ 8,344	Net income attributable to ONEOK Partners

K. LIMITED PARTNERS' NET INCOME PER UNIT

Limited partners' net income per unit is computed by dividing net income attributable to ONEOK Partners, L.P., after deducting the general partner's allocation as discussed below, by the weighted-average number of outstanding limited partner units, which includes our common and Class B limited partner units. Because ONEOK has conditionally waived its right to increased quarterly distributions, until it gives 90 days notice of the withdrawal of the waiver, currently each Class B and common unit share equally in the earnings of the Partnership, and neither has any liquidation or other preferences.

ONEOK Partners GP owns the entire 2 percent general partnership interest in us, which entitles it to incentive distribution rights that provide for an increasing proportion of cash distributions from the Partnership as the distributions made to limited partners increase above specified levels. For purposes of our calculation of limited partners' net income per unit, net income attributable to ONEOK Partners, L.P. is allocated to the general partner as follows: (i) an amount based upon the 2 percent general partner interest in net income attributable to ONEOK Partners, L.P.; and (ii) the amount of the general partner's incentive distribution rights based on the total cash distributions declared for the period. The amount of incentive distributions allocated to our general partner totaled $382.8 million, $326.0 million and $259.5 million for 2015, 2014 and 2013, respectively.

The terms of our Partnership Agreement limit the general partner's incentive distribution to the amount of available cash calculated for the period. As such, incentive distribution rights are not allocated on undistributed earnings. For additional information regarding our general partner's incentive distribution rights, see "Partnership Agreement" in Note I.

L. INCOME TAXES

The following table sets forth our provision for income taxes for the periods indicated:

	Years Ended December 31,		
	2015	**2014**	**2013**
	(Thousands of dollars)		
Current income tax provision			
Federal	**$ —**	$ 59	$ 56
State	**(621)**	1,777	5,358
Total current income tax provision	**(621)**	1,836	5,414
Deferred income tax provision			
Federal	**5,413**	5,033	4,303
State	**(648)**	5,799	1,141
Total deferred income tax provision	**4,765**	10,832	5,444
Total provision for income taxes	**$ 4,144**	$ 12,668	$ 10,858

The following table is a reconciliation of our income tax provision for the periods indicated:

	Years Ended December 31,		
	2015	**2014**	**2013**
	(Thousands of dollars)		
Income before income taxes	**$ 602,016**	$ 924,003	$ 814,841
Less: Net income attributable to noncontrolling interests	**8,330**	1,037	357
Income attributable to ONEOK Partners, L.P. before income taxes	**593,686**	922,966	814,484
Federal statutory income tax rate	**35.0%**	35.0%	35.0%
Provision for federal income taxes	**207,790**	323,038	285,069
Partnership earnings not subject to tax	**(202,143)**	(318,021)	(280,992)
State income taxes, net of federal benefit	**(2,078)**	7,576	6,095
State deferred tax rate change, net of valuation allowance	**810**	—	—
Other, net	**(235)**	75	686
Income tax provision	**$ 4,144**	$ 12,668	$ 10,858

The following table sets forth the tax effects of temporary differences that gave rise to significant portions of the deferred tax assets and liabilities for the periods indicated.

	Years Ended December 31, 2015	Years Ended December 31, 2014
	(*Thousands of dollars*)	
Deferred tax assets		
Federal and state net operating loss	**$ 4,224**	$ 3,179
Other	**7**	1,626
Total deferred tax assets	**4,231**	4,805
Deferred tax liabilities		
Excess of tax over book depreciation	**67,265**	61,120
Regulatory assets	**49**	1,962
Total deferred tax liabilities	**67,314**	63,082
Net deferred tax liabilities	**$ 63,083**	$ 58,277

M. UNCONSOLIDATED AFFILIATES

Investments in Unconsolidated Affiliates - The following table sets forth our investments in unconsolidated affiliates for the periods indicated:

	Net Ownership Interest	December 31, 2015	December 31, 2014
		(*Thousands of dollars*)	
Northern Border Pipeline	50%	**$ 363,231**	$ 387,253
Overland Pass Pipeline Company	50%	**459,354**	466,977
Other	Various	**125,636**	278,423
Investments in unconsolidated affiliates (a)		**$ 948,221**	$ 1,132,653

(a) - Equity-method goodwill (Note A) was $40.1 million and $170.9 million at December 31, 2015 and 2014, respectively.

Equity in Net Earnings from Investments and Impairments - The following table sets forth our equity in net earnings from investments for the periods indicated:

	Years Ended December 31, 2015	2014	2013
		(*Thousands of dollars*)	
Northern Border Pipeline	**$ 66,941**	$ 69,819	$ 65,046
Overland Pass Pipeline Company	**37,783**	25,906	20,461
Other	**20,576**	21,690	25,010
Equity in net earnings from investments	**$ 125,300**	$ 117,415	$ 110,517
Impairment of equity investments	**$ (180,583)**	$ (76,412)	$ —

Unconsolidated Affiliates Financial Information - The following tables set forth summarized combined financial information of our unconsolidated affiliates for the periods indicated:

	December 31, 2015	December 31, 2014
	(Thousands of dollars)	
Balance Sheet		
Current assets	**$ 149,439**	$ 153,293
Property, plant and equipment, net	**$ 2,556,559**	$ 2,440,714
Other noncurrent assets	**$ 23,722**	$ 35,668
Current liabilities	**$ 211,037**	$ 95,026
Long-term debt	**$ 425,521**	$ 428,385
Other noncurrent liabilities	**$ 69,356**	$ 73,767
Accumulated other comprehensive loss	**$ (5,669)**	$ (2,063)
Owners’ equity	**$ 2,029,475**	$ 2,034,560

	Years Ended December 31,		
	2015	2014	2013
		(Thousands of dollars)	
Income Statement			
Operating revenues	**$ 524,496**	$ 548,491	$ 528,665
Operating expenses (a)	**$ 304,930**	$ 309,990	$ 256,292
Net income (a)	**$ 200,064**	$ 214,410	$ 248,998
Distributions paid to us	**$ 155,918**	$ 139,019	$ 137,498

(a) Includes long-lived asset impairment charges in 2015 and 2014.

We incurred expenses in transactions with unconsolidated affiliates of $104.7 million, $62.0 million and $53.8 million for 2015, 2014 and 2013, respectively, primarily related to Overland Pass Pipeline Company and Northern Border Pipeline. Accounts payable to our equity-method investees at December 31, 2015 and 2014, was $8.0 million and $20.5 million, respectively.

Overland Pass Pipeline Company - The Overland Pass Pipeline Company limited liability company agreement provides that distributions to Overland Pass Pipeline Company’s members are to be made on a pro rata basis according to each member’s percentage interest. The Overland Pass Pipeline Company Management Committee determines the amount and timing of such distributions. Any changes to, or suspension of, the cash distributions from Overland Pass Pipeline Company requires the unanimous approval of the Overland Pass Pipeline Management Committee. Cash distributions are equal to 100 percent of available cash as defined in the limited liability company agreement.

Northern Border Pipeline - The Northern Border Pipeline partnership agreement provides that distributions to Northern Border Pipeline’s partners are to be made on a pro rata basis according to each partner’s percentage interest. The Northern Border Pipeline Management Committee determines the amount and timing of such distributions. Any changes to, or suspension of, the cash distribution policy of Northern Border Pipeline requires the unanimous approval of the Northern Border Pipeline Management Committee. Cash distributions are equal to 100 percent of distributable cash flow as determined from Northern Border Pipeline’s financial statements based upon EBITDA less interest expense and maintenance capital expenditures. Loans or other advances from Northern Border Pipeline to its partners or affiliates are prohibited under its credit agreement.

During 2013, we made equity contributions to Northern Border Pipeline of $30.8 million.

Roadrunner Gas Transmission - In March 2015, we entered into a 50-50 joint venture with a subsidiary of Fermaca, a Mexico City-based natural gas infrastructure company, to construct a pipeline to transport natural gas from the Permian Basin in West Texas to the Mexican border near El Paso, Texas. During year ended December 31, 2015, we contributed approximately $30 million to Roadrunner.

The Roadrunner limited liability agreement provides that distributions to members are made on a pro rata basis according to each member’s ownership interest. Cash distributions are paid within 45 days following the end of each quarter. Any changes to, or suspension of, the cash distributions from Roadrunner requires approval of the Roadrunner Management Committee. Voting rights for the Roadrunner Management Committee are allocated on a pro rata basis according to each member's ownership interest. Cash distributions are equal to 100 percent of available cash, as defined in the limited liability company agreement.

Impairment Charges - Crude oil and natural gas producers have primarily focused their development efforts on crude oil and NGL-rich supply basins rather than in areas with dry natural gas production, such as the coal-bed methane production areas in the Powder River Basin. The reduced development activities and production declines in the dry natural gas area of the Powder River Basin have resulted in lower natural gas volumes available to be gathered. Due to the continued and greater than expected decline in volumes gathered in the coal-bed methane area of the Powder River Basin, we evaluated our assets and investments in this area and determined that we will cease operations of our wholly owned coal-bed methane natural gas gathering system in 2016. Bighorn Gas Gathering, in which we own a 49 percent equity interest, and Fort Union Gas Gathering, in which we own a 37 percent equity interest, are both partially supplied with volumes from our wholly owned coal-bed methane natural gas gathering system. We own a 35 percent equity interest in Lost Creek Gathering Company, which also is located in a dry natural gas area. We reviewed our Bighorn Gas Gathering, Fort Union Gas Gathering and Lost Creek Gathering Company equity investments and recorded noncash impairment charges of $180.6 million in the fourth quarter 2015. The remaining net book value of our equity investments in this dry natural gas area is $35.0 million.

During 2014, Bighorn Gas Gathering recorded an impairment of its underlying assets when the operator determined that the volume decline would be sustained for the foreseeable future. As a result, we reviewed our equity investment in Bighorn Gas Gathering for impairment and recorded noncash impairment charges of $76.4 million in 2014. The 2014 impairment charges have been reclassified in the consolidated financial statements and notes to conform to the current year presentation. There were no impairments to investments in unconsolidated affiliates in 2013.

N. RELATED-PARTY TRANSACTIONS

Prior to April 1, 2014, our Natural Gas Gathering and Processing segment sold natural gas to ONEOK and its subsidiaries, and our Natural Gas Pipelines segment provided transportation and storage services to ONEOK and its subsidiaries. Additionally, our Natural Gas Gathering and Processing segment and Natural Gas Liquids segment purchased a portion of the natural gas used in their operations from ONEOK and its subsidiaries.

On January 31, 2014, ONEOK completed the separation of its former natural gas distribution business into ONE Gas. ONE Gas was an affiliate prior to this separation. Commodity sales and services revenues in the Consolidated Statements of Income for the one month ended January 31, 2014, and for the year ended December 31, 2013, for transactions with ONE Gas prior to the separation are reflected as affiliate transactions. Transactions with ONE Gas that occurred after the separation are reflected as unaffiliated, third-party transactions.

On March 31, 2014, ONEOK completed the wind down of ONEOK Energy Services Company, a subsidiary of ONEOK. For the first quarter 2014 and the year ended December 31, 2013, we had transactions with ONEOK Energy Services Company, which are reflected as affiliate transactions.

Under the Services Agreement with ONEOK and ONEOK Partners GP (the Services Agreement), our operations and the operations of ONEOK and its affiliates can combine or share certain common services in order to operate more efficiently and cost effectively. Under the Services Agreement, ONEOK provides to us similar services that it provides to its affiliates, including those services required to be provided pursuant to our Partnership Agreement. ONEOK Partners GP may purchase services from ONEOK and its affiliates pursuant to the terms of the Services Agreement. ONEOK Partners GP has no employees and utilizes the services of ONEOK to fulfill its operating obligations.

ONEOK and its affiliates provide a variety of services to us under the Services Agreement, including cash management and financial services, employee benefits provided through ONEOK's benefit plans, legal and administrative services, insurance and office space leased in ONEOK's headquarters building and other field locations. Where costs are incurred specifically on behalf of one of our affiliates, the costs are billed directly to us by ONEOK. In other situations, the costs may be allocated to us through a variety of methods, depending upon the nature of the expense and activities. Beginning in the second quarter 2014, ONEOK allocates substantially all of its general overhead costs to us as a result of ONEOK's separation of its natural gas distribution business and the wind down of its energy services business in the first quarter 2014. For the first quarter 2014 and the year ended December 31, 2013, it is not practicable to determine what these general overhead costs would have been on a stand-alone basis. All costs directly charged or allocated to us are included in our Consolidated Statements of Income.

The following table sets forth the transactions with related parties for the periods indicated:

	Years Ended December 31, 2015	2014	2013
	(Thousands of dollars)		
Revenues	**$ —**	$ 53,526	$ 340,743
Expenses			
Cost of sales and fuel	**$ —**	$ 10,835	$ 37,963
Operating expenses	**368,346**	330,541	265,448
Total expenses	**$ 368,346**	$ 341,376	$ 303,411

ONEOK Partners GP made additional general partner contributions to us of approximately $21.0 million, $23.2 million and $12.4 million in 2015, 2014 and 2013, respectively, to maintain its 2 percent general partner interest in connection with the issuances of common units. See Note I for additional information about cash distributions paid to ONEOK for its general partner and limited partner interests.

O. COMMITMENTS AND CONTINGENCIES

Commitments - Operating leases represent future minimum lease payments under noncancelable leases covering office space and pipeline equipment. Rental expense in 2015, 2014 and 2013 was not material. We have no material operating leases. Firm transportation and storage contracts are fixed-price contracts that provide us with firm transportation and storage capacity. The following table sets forth our firm transportation and storage contract payments for our continuing operations for the periods indicated:

	Firm Transportation and Storage Contracts
	(Millions of dollars)
2016	$ 45.8
2017	42.1
2018	40.6
2019	36.2
2020	35.8
Thereafter	47.9
Total	$ 248.4

Environmental Matters and Pipeline Safety - The operation of pipelines, plants and other facilities for the gathering, processing, transportation and storage of natural gas, NGLs, condensate, and other products is subject to numerous and complex laws and regulations pertaining to health, safety and the environment. As an owner and/or operator of these facilities we must comply with United States laws and regulations at the federal, state and local levels that relate to air and water quality, hazardous and solid waste management and disposal, and other environmental matters. The cost of planning, designing, constructing and operating pipelines, plants and other facilities must incorporate compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and potentially criminal enforcement measures, including citizen suits, which can include the assessment of monetary penalties, the imposition of remedial requirements and the issuance of injunctions or restrictions on operation. Management believes that, based on currently known information, compliance with these laws and regulations will not have a material adverse effect on our results of operations, financial condition or cash flows.

Legal Proceedings - We are a party to various litigation matters and claims that have arisen in the normal course of our operations. While the results of these litigation matters and claims cannot be predicted with certainty, we believe the reasonably possible losses from such matters, individually and in the aggregate, are not material. Additionally, we believe the probable final outcome of such matters will not have a material adverse effect on our consolidated results of operations, financial position or cash flows.

P. SEGMENTS

Segment Descriptions - Our operations are divided into three reportable business segments, as follows:

- our Natural Gas Gathering and Processing segment gathers, treats and processes natural gas;
- our Natural Gas Liquids segment gathers, treats, fractionates and transports NGLs and stores, markets and distributes NGL products; and
- our Natural Gas Pipelines segment operates regulated interstate and intrastate natural gas transmission pipelines and natural gas storage facilities.

Accounting Policies - We evaluate performance based principally on each segment's operating income and equity in net earnings. The accounting policies of the segments are described in Note A. As a result of ONEOK's separation of its natural gas distribution business into a stand-alone publicly traded company called ONE Gas on January 31, 2014, transactions with ONE Gas subsequent to the separation are reflected as sales to unaffiliated customers.

Customers - The primary customers for our Natural Gas Gathering and Processing segment are major and independent crude oil and natural gas production companies. Our Natural Gas Liquids segment's customers are primarily NGL and natural gas gathering and processing companies, major and independent crude oil and natural gas production companies, propane distributors, ethanol producers and petrochemical, refining and NGL marketing companies. Our Natural Gas Pipelines segment's customers include natural gas distribution, electric-generation, natural gas marketing, industrial and major and independent crude oil and natural gas production companies.

For the years ended December 31, 2015, 2014 and 2013, we had no single customer from which we received 10 percent or more of our consolidated revenues.

See Note N for additional information about our sales to affiliated customers.

Operating Segment Information - The following tables set forth certain selected financial information for our operating segments for the periods indicated:

Year Ended December 31, 2015	Natural Gas Gathering and Processing	Natural Gas Liquids (a)	Natural Gas Pipelines (b)	Other and Eliminations	Total
			(Thousands of dollars)		
Sales to unaffiliated customers	$ 1,187,390	$ 6,248,002	$ 325,676	$ —	$ 7,761,068
Intersegment revenues	649,726	331,697	6,771	(988,194)	—
Total revenues	1,837,116	6,579,699	332,447	(988,194)	7,761,068
Cost of sales and fuel (exclusive of items shown separately below)	1,265,617	5,328,256	34,481	(987,302)	5,641,052
Operating costs	272,418	314,505	105,720	(467)	692,176
Depreciation and amortization	150,008	158,709	43,479	—	352,196
Impairment of long-lived assets	73,681	9,992	—	—	83,673
Gain (loss) on sale of assets	2,775	(939)	4,272	—	6,108
Operating income	$ 78,167	$ 767,298	$ 153,039	$ (425)	$ 998,079
Equity in net earnings from investments	$ 17,863	$ 38,696	$ 68,741	$ —	$ 125,300
Impairment of equity investments	$ (180,583)	$ —	$ —	$ —	$ (180,583)
Investments in unconsolidated affiliates	$ 73,920	$ 482,672	$ 391,629	$ —	$ 948,221
Total assets	$ 5,123,450	$ 8,017,799	$ 1,844,401	$ (58,064)	$ 14,927,586
Noncontrolling interests in consolidated subsidiaries	$ 4,041	$ 160,084	$ —	$ —	$ 164,125
Capital expenditures	$ 887,938	$ 226,135	$ 58,215	$ 13,835	$ 1,186,123

(a) - Our Natural Gas Liquids segment has regulated and nonregulated operations. Our Natural Gas Liquids segment's regulated operations had revenues of $954.8 million, of which $770.1 million related to sales within the segment, cost of sales and fuel of $412.6 million and operating income of $306.9 million.
(b) - Our Natural Gas Pipelines segment has regulated and nonregulated operations. Our Natural Gas Pipelines segment's regulated operations had revenues of $266.9 million, cost of sales and fuel of $31.1 million and operating income of $103.7 million.

Year Ended December 31, 2014	Natural Gas Gathering and Processing	Natural Gas Liquids (a)	Natural Gas Pipelines (b)	Other and Eliminations	Total
			(Thousands of dollars)		
Sales to unaffiliated customers	$ 1,478,729	$ 10,329,609	$ 329,801	$ —	$ 12,138,139
Sales to affiliated customers	41,214	—	12,312	—	53,526
Intersegment revenues	1,447,665	215,772	8,343	(1,671,780)	—
Total revenues	2,967,608	10,545,381	350,456	(1,671,780)	12,191,665
Cost of sales and fuel (exclusive of items shown separately below)	2,305,723	9,435,296	21,935	(1,674,406)	10,088,548
Operating costs	257,658	296,402	111,037	4,560	669,657
Depreciation and amortization	123,847	124,071	43,318	—	291,236
Gain (loss) on sale of assets	219	(572)	6,786	166	6,599
Operating income	$ 280,599	$ 689,040	$ 180,952	$ (1,768)	$ 1,148,823
Equity in net earnings from investments	$ 20,271	$ 27,326	$ 69,818	$ —	$ 117,415
Impairment of equity investments	$ (76,412)	$ —	$ —	$ —	$ (76,412)
Investments in unconsolidated affiliates	$ 254,818	$ 490,582	$ 387,253	$ —	$ 1,132,653
Total assets	$ 4,911,283	$ 8,143,575	$ 1,823,713	$ (278,171)	$ 14,600,400
Noncontrolling interests in consolidated subsidiaries	$ 4,251	$ 163,671	$ —	$ 15	$ 167,937
Capital expenditures	$ 898,896	$ 798,048	$ 42,991	$ 6,055	$ 1,745,990

(a) - Our Natural Gas Liquids segment has regulated and nonregulated operations. Our Natural Gas Liquids segment's regulated operations had revenues of $695.9 million, of which $598.1 million related to sales within the segment, cost of sales and fuel of $309.4 million and operating income of $196.1 million.
(b) - Our Natural Gas Pipelines segment has regulated and nonregulated operations. Our Natural Gas Pipelines segment's regulated operations had revenues of $290.0 million, cost of sales and fuel of $47.7 million and operating income of $106.5 million.

Year Ended December 31, 2013	Natural Gas Gathering and Processing	Natural Gas Liquids (a)	Natural Gas Pipelines (b)	Other and Eliminations	Total
			(Thousands of dollars)		
Sales to unaffiliated customers	$ 665,169	$ 10,644,117	$ 219,244	$ —	$ 11,528,530
Sales to affiliated customers	238,600	—	102,143	—	340,743
Intersegment revenues	1,147,713	133,910	4,127	(1,285,750)	—
Total revenues	2,051,482	10,778,027	325,514	(1,285,750)	11,869,273
Cost of sales and fuel (exclusive of items shown separately below)	1,550,855	9,908,089	39,795	(1,276,526)	10,222,213
Operating costs	193,293	236,638	101,182	(9,600)	521,513
Depreciation and amortization	103,962	89,240	43,541	—	236,743
Loss on sale of assets	436	843	10,602	—	11,881
Operating income	$ 203,808	$ 544,903	$ 151,598	$ 376	$ 900,685
Equity in net earnings from investments	$ 23,493	$ 21,978	$ 65,046	$ —	$ 110,517
Investments in unconsolidated affiliates	$ 333,179	$ 491,856	$ 404,803	$ —	$ 1,229,838
Total assets	$ 3,949,813	$ 6,938,633	$ 1,817,445	$ 118,269	$ 12,824,160
Noncontrolling interests in consolidated subsidiaries	$ 4,521	$ —	$ —	$ 15	$ 4,536
Capital expenditures	$ 774,379	$ 1,128,345	$ 34,699	$ 1,903	$ 1,939,326

(a) - Our Natural Gas Liquids segment has regulated and nonregulated operations. Our Natural Gas Liquids segment's regulated operations had revenues of $534.8 million, of which $449.9 million related to sales within the segment, cost of sales and fuel of $207.4 million and operating income of $190.5 million.
(b) - Our Natural Gas Pipelines segment has regulated and nonregulated operations. Our Natural Gas Pipelines segment's regulated operations had revenues of $246.9 million, cost of sales and fuel of $29.3 million and operating income of $90.5 million.

Q. QUARTERLY FINANCIAL DATA (UNAUDITED)

Year Ended December 31, 2015	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(Thousands of dollars, except per unit amounts)			
Revenues	**$ 1,804,759**	**$ 2,127,507**	**$ 1,898,418**	**$ 1,930,384**
Net income	**$ 147,032**	**$ 211,610**	**$ 229,665**	**$ 9,565**
Net income attributable to ONEOK Partners, L.P.	**$ 145,594**	**$ 209,770**	**$ 226,961**	**$ 7,217**
Limited partners' per unit net income (loss)	**$ 0.21**	**$ 0.44**	**$ 0.45**	**$ (0.33)**

The fourth quarter 2015 includes noncash impairment charges of $264.3 million related to long-lived assets and equity investments.

Year Ended December 31, 2014	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(Thousands of dollars, except per unit amounts)			
Revenues	$ 3,162,303	$ 3,065,735	$ 3,119,369	$ 2,844,258
Net income	$ 265,468	$ 214,511	$ 167,320	$ 264,036
Net income attributable to ONEOK Partners, L.P.	$ 265,392	$ 214,434	$ 167,247	$ 263,225
Limited partners' per unit net income	$ 0.81	$ 0.54	$ 0.32	$ 0.67

The third quarter 2014 includes noncash impairment charges of $76.4 million related to equity investments.

R. SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

We have no significant assets or operations other than our investment in our wholly owned subsidiary, the Intermediate Partnership. The Intermediate Partnership holds all our partnership interests and equity in our subsidiaries, as well as a 50 percent interest in Northern Border Pipeline. Our Intermediate Partnership guarantees our senior notes and borrowings, if any, under the Partnership Credit Agreement. The Intermediate Partnership's guarantee of our senior notes and of any borrowings under the Partnership Credit Agreement are full and unconditional, subject to certain customary automatic release provisions.

For purposes of the following footnote:

- we are referred to as "Parent";
- the Intermediate Partnership is referred to as "Guarantor Subsidiary"; and
- the "Non-Guarantor Subsidiaries" are all subsidiaries other than the Guarantor Subsidiary.

The following supplemental condensed consolidating financial information is presented on an equity-method basis reflecting the Parent's separate accounts, the Guarantor Subsidiary's separate accounts, the combined accounts of the Non-Guarantor Subsidiaries, the combined consolidating adjustments and eliminations and the Parent's consolidated amounts for the periods indicated.

Condensed Consolidating Statements of Income

	Year Ended December 31, 2015				
	Parent	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
			(Millions of dollars)		
Revenues					
Commodity sales	$ —	$ —	$ 6,098.3	$ —	$ 6,098.3
Services	—	—	1,662.8	—	1,662.8
Total revenues	—	—	7,761.1	—	7,761.1
Cost of sales and fuel (exclusive of items shown separately below)	—	—	5,641.1	—	5,641.1
Impairment of long-lived assets	—	—	83.7	—	83.7
Operating expenses	—	—	1,044.3	—	1,044.3
Gain (loss) on sale of assets	—	—	6.1	—	6.1
Operating income	—	—	998.1	—	998.1
Equity in net earnings from investments	589.5	589.5	58.4	(1,112.1)	125.3
Impairment of equity investments	—	—	(180.6)	—	(180.6)
Other income (expense), net	371.0	371.0	(1.9)	(742.0)	(1.9)
Interest expense	(371.0)	(371.0)	(338.9)	742.0	(338.9)
Income before income taxes	589.5	589.5	535.1	(1,112.1)	602.0
Income taxes	—	—	(4.1)	—	(4.1)
Net income	589.5	589.5	531.0	(1,112.1)	597.9
Less: Net income attributable to noncontrolling interests	—	—	8.4	—	8.4
Net income attributable to ONEOK Partners, L.P.	$ 589.5	$ 589.5	$ 522.6	$ (1,112.1)	$ 589.5

	Year Ended December 31, 2014				
	Parent	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
			(Millions of dollars)		
Revenues					
Commodity sales	$ —	$ —	$ 10,725.0	$ —	$ 10,725.0
Services	—	—	1,466.7	—	1,466.7
Total revenues	—	—	12,191.7	—	12,191.7
Cost of sales and fuel (exclusive of items shown separately below)	—	—	10,088.6	—	10,088.6
Operating expenses	—	—	960.9	—	960.9
Gain (loss) on sale of assets	—	—	6.6	—	6.6
Operating income	—	—	1,148.8	—	1,148.8
Equity in net earnings from investments	910.3	910.3	47.6	(1,750.8)	117.4
Impairment of equity investments	—	—	(76.4)	—	(76.4)
Other income (expense), net	331.7	331.7	16.1	(663.4)	16.1
Interest expense,net	(331.7)	(331.7)	(281.9)	663.4	(281.9)
Income before income taxes	910.3	910.3	854.2	(1,750.8)	924.0
Income taxes	—	—	(12.7)	—	(12.7)
Net income	910.3	910.3	841.5	(1,750.8)	911.3
Less: Net income attributable to noncontrolling interests	—	—	1.0	—	1.0
Net income attributable to ONEOK Partners, L.P.	$ 910.3	$ 910.3	$ 840.5	$ (1,750.8)	$ 910.3

	Year Ended December 31, 2013				
	Parent	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
			(*Millions of dollars*)		
Revenues					
Commodity sales	$ —	$ —	$ 10,549.2	$ —	$ 10,549.2
Services	—	—	1,320.1	—	1,320.1
Total revenues	—	—	11,869.3	—	11,869.3
Cost of sales and fuel (exclusive of items shown separately below)	—	—	10,222.2	—	10,222.2
Operating expenses	—	—	758.3	—	758.3
Gain (loss) on sale of assets	—	—	11.9	—	11.9
Operating income	—	—	900.7	—	900.7
Equity in net earnings from investments	803.6	803.6	45.5	(1,542.2)	110.5
Other income (expense), net	287.6	287.6	40.3	(575.2)	40.3
Interest expense	(287.6)	(287.6)	(236.7)	575.2	(236.7)
Income before income taxes	803.6	803.6	749.8	(1,542.2)	814.8
Income taxes	—	—	(10.8)	—	(10.8)
Net income	803.6	803.6	739.0	(1,542.2)	804.0
Less: Net income attributable to noncontrolling interests	—	—	0.4	—	0.4
Net income attributable to ONEOK Partners, L.P.	$ 803.6	$ 803.6	$ 738.6	$ (1,542.2)	$ 803.6

Condensed Consolidating Statements of Comprehensive Income

	Year Ended December 31, 2015				
	Parent	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
	(Millions of dollars)				
Net income	**$ 589.5**	**$ 589.5**	**$ 531.0**	**$ (1,112.1)**	**$ 597.9**
Other comprehensive income (loss)					
Unrealized gains (losses) on derivatives	**45.6**	**68.1**	**68.1**	**(136.2)**	**45.6**
Realized (gains) losses on derivatives recognized in net income	**(67.0)**	**(81.1)**	**(81.1)**	**162.2**	**(67.0)**
Total other comprehensive income (loss)	**(21.4)**	**(13.0)**	**(13.0)**	**26.0**	**(21.4)**
Comprehensive income	**568.1**	**576.5**	**518.0**	**(1,086.1)**	**576.5**
Less: Comprehensive income attributable to noncontrolling interests	**—**	**—**	**8.4**	**—**	**8.4**
Comprehensive income attributable to ONEOK Partners, L.P.	**$ 568.1**	**$ 576.5**	**$ 509.6**	**$ (1,086.1)**	**$ 568.1**

	Year Ended December 31, 2014				
	Parent	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
	(Millions of dollars)				
Net income	$ 910.3	$ 910.3	$ 841.5	$ (1,750.8)	$ 911.3
Other comprehensive income (loss)					
Unrealized gains (losses) on derivatives	(64.6)	32.4	32.4	(64.8)	(64.6)
Realized (gains) losses on derivatives recognized in net income	31.6	21.1	21.1	(42.2)	31.6
Total other comprehensive income (loss)	(33.0)	53.5	53.5	(107.0)	(33.0)
Comprehensive income	877.3	963.8	895.0	(1,857.8)	878.3
Less: Comprehensive income attributable to noncontrolling interests	—	—	1.0	—	1.0
Comprehensive income attributable to ONEOK Partners, L.P.	$ 877.3	$ 963.8	$ 894.0	$ (1,857.8)	$ 877.3

	Year Ended December 31, 2013				
	Parent	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
	(Millions of dollars)				
Net income	$ 803.6	$ 803.6	$ 739.0	$ (1,542.2)	$ 804.0
Other comprehensive income (loss)					
Unrealized gains (losses) on derivatives	32.1	(14.5)	(14.5)	29.0	32.1
Realized (gains) losses on derivatives recognized in net income	8.4	(1.7)	(1.7)	3.4	8.4
Total other comprehensive income (loss)	40.5	(16.2)	(16.2)	32.4	40.5
Comprehensive income	844.1	787.4	722.8	(1,509.8)	844.5
Less: Comprehensive income attributable to noncontrolling interests	—	—	0.4	—	0.4
Comprehensive income attributable to ONEOK Partners, L.P.	$ 844.1	$ 787.4	$ 722.4	$ (1,509.8)	$ 844.1

Condensed Consolidating Balance Sheets

	December 31, 2015				
	Parent	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
Assets			(*Millions of dollars*)		
Current assets					
Cash and cash equivalents	$ —	$ 5.1	$ —	$ —	$ 5.1
Accounts receivable, net	—	—	593.4	—	593.4
Affiliate receivables	—	—	8.0	—	8.0
Natural gas and natural gas liquids in storage	—	—	128.1	—	128.1
Materials and supplies	—	—	76.7	—	76.7
Other current assets	4.1	—	67.8	—	71.9
Total current assets	4.1	5.1	874.0	—	883.2
Property, plant and equipment					
Property, plant and equipment	—	—	14,307.5	—	14,307.5
Accumulated depreciation and amortization	—	—	2,050.7	—	2,050.7
Net property, plant and equipment	—	—	12,256.8	—	12,256.8
Investments and other assets					
Intercompany notes receivable	10,144.9	7,781.8	—	(17,926.7)	—
Other assets	3,594.0	5,952.0	1,425.2	(9,183.6)	1,787.6
Total investments and other assets	13,738.9	13,733.8	1,425.2	(27,110.3)	1,787.6
Total assets	$ 13,743.0	$ 13,738.9	$ 14,556.0	$ (27,110.3)	$ 14,927.6
Liabilities and equity					
Current liabilities					
Current maturities of long-term debt	$ 100.0	$ —	$ 7.7	$ —	$ 107.7
Short-term borrowings	546.3	—	—	—	546.3
Accounts payable	—	—	605.4	—	605.4
Affiliate payables	—	—	27.1	—	27.1
Other current liabilities	112.5	—	181.4	—	293.9
Total current liabilities	758.8	—	821.6	—	1,580.4
Intercompany debt	—	10,144.9	7,781.8	(17,926.7)	—
Long-term debt, excluding current maturities	6,651.0	—	44.3	—	6,695.3
Deferred credits and other liabilities	—	—	154.6	—	154.6
Commitments and contingencies					
Equity					
Equity excluding noncontrolling interests in consolidated subsidiaries	6,333.2	3,594.0	5,589.6	(9,183.6)	6,333.2
Noncontrolling interests in consolidated subsidiaries	—	—	164.1	—	164.1
Total equity	6,333.2	3,594.0	5,753.7	(9,183.6)	6,497.3
Total liabilities and equity	$ 13,743.0	$ 13,738.9	$ 14,556.0	$ (27,110.3)	$ 14,927.6

	December 31, 2014				
	Parent	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
Assets			(*Millions of dollars*)		
Current assets					
Cash and cash equivalents	$ —	$ 42.5	$ —	$ —	$ 42.5
Accounts receivable, net	—	—	735.8	—	735.8
Affiliate receivables	—	—	8.6	—	8.6
Natural gas and natural gas liquids in storage	—	—	134.1	—	134.1
Materials and supplies	—	—	55.8	—	55.8
Other current assets	1.9	—	107.3	—	109.2
Total current assets	1.9	42.5	1,041.6	—	1,086.0
Property, plant and equipment					
Property, plant and equipment	—	—	13,377.6	—	13,377.6
Accumulated depreciation and amortization	—	—	1,842.1	—	1,842.1
Net property, plant and equipment	—	—	11,535.5	—	11,535.5
Investments and other assets					
Intercompany notes receivable	8,843.3	7,579.0	—	(16,422.3)	—
Other assets	4,250.1	5,469.8	1,590.3	(9,331.3)	1,978.9
Total investments and other assets	13,093.4	13,048.8	1,590.3	(25,753.6)	1,978.9
Total assets	$ 13,095.3	$ 13,091.3	$ 14,167.4	$ (25,753.6)	$ 14,600.4
Liabilities and equity					
Current liabilities					
Current maturities of long-term debt	$ —	$ —	$ 7.7	$ —	$ 7.7
Short-term borrowings	1,055.3	—	—	—	1,055.3
Accounts payable	—	—	874.7	—	874.7
Affiliate payables	—	—	36.1	—	36.1
Other current liabilities	136.8	—	225.5	—	362.3
Total current liabilities	1,192.1	—	1,144.0	—	2,336.1
Intercompany debt	—	8,843.3	7,579.0	(16,422.3)	—
Long-term debt, excluding current maturities	5,952.4	—	51.9	—	6,004.3
Deferred credits and other liabilities	—	—	141.3	—	141.3
Commitments and contingencies					
Equity					
Equity excluding noncontrolling interests in consolidated subsidiaries	5,950.8	4,248.0	5,083.3	(9,331.3)	5,950.8
Noncontrolling interests in consolidated subsidiaries	—	—	167.9	—	167.9
Total equity	5,950.8	4,248.0	5,251.2	(9,331.3)	6,118.7
Total liabilities and equity	$ 13,095.3	$ 13,091.3	$ 14,167.4	$ (25,753.6)	$ 14,600.4

Condensed Consolidating Statements of Cash Flows

	Year Ended December 31, 2015				
	Parent	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
			(*Millions of dollars*)		
Operating activities					
Cash provided by operating activities	**$ 1,196.7**	**$ 66.9**	**$ 1,038.9**	**$ (1,230.5)**	**$ 1,072.0**
Investing activities					
Capital expenditures	**—**	**—**	**(1,186.1)**	**—**	**(1,186.1)**
Other investing activities	**—**	**24.1**	**(26.5)**	**—**	**(2.4)**
Cash provided by (used in) investing activities	**—**	**24.1**	**(1,212.6)**	**—**	**(1,188.5)**
Financing activities					
Cash distributions:					
General and limited partners	**(1,230.5)**	**(1,230.5)**	**—**	**1,230.5**	**(1,230.5)**
Noncontrolling interests	**—**	**—**	**(11.7)**	**—**	**(11.7)**
Intercompany borrowings (advances), net	**(1,295.1)**	**1,102.1**	**193.0**	**—**	**—**
Borrowing (repayment) of short-term borrowings, net	**(509.0)**	**—**	**—**	**—**	**(509.0)**
Issuance of long-term debt, net of discounts	**798.9**	**—**	**—**	**—**	**798.9**
Debt financing costs	**(7.7)**	**—**	**—**	**—**	**(7.7)**
Repayment of long-term debt	**—**	**—**	**(7.6)**	**—**	**(7.6)**
Issuance of common units, net of issuance costs	**1,025.7**	**—**	**—**	**—**	**1,025.7**
Contribution from general partner	**21.0**	**—**	**—**	**—**	**21.0**
Cash provided by (used in) financing activities	**(1,196.7)**	**(128.4)**	**173.7**	**1,230.5**	**79.1**
Change in cash and cash equivalents	**—**	**(37.4)**	**—**	**—**	**(37.4)**
Cash and cash equivalents at beginning of period	**—**	**42.5**	**—**	**—**	**42.5**
Cash and cash equivalents at end of period	**$ —**	**$ 5.1**	**$ —**	**$ —**	**$ 5.1**

	Year Ended December 31, 2014				
	Parent	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
			(*Millions of dollars*)		
Operating activities					
Cash provided by operating activities	$ 1,155.7	$ 69.8	$ 1,136.5	$ (1,052.2)	$ 1,309.8
Investing activities					
Capital expenditures	—	—	(1,746.0)	—	(1,746.0)
Other investing activities	—	17.7	(804.7)	—	(787.0)
Cash provided by (used in) investing activities	—	17.7	(2,550.7)	—	(2,533.0)
Financing activities					
Cash distributions:					
General and limited partners	(1,052.2)	(1,052.2)	—	1,052.2	(1,052.2)
Noncontrolling interests	—	—	(0.6)	—	(0.6)
Intercompany borrowings (advances), net	(2,295.2)	872.7	1,422.5	—	—
Borrowing (repayment) of short-term borrowings, net	1,055.3	—	—	—	1,055.3
Repayment of long-term debt	—	—	(7.7)	—	(7.7)
Issuance of common units, net of issuance costs	1,113.1	—	—	—	1,113.1
Contribution from general partner	23.3	—	—	—	23.3
Cash provided by (used in) financing activities	(1,155.7)	(179.5)	1,414.2	1,052.2	1,131.2
Change in cash and cash equivalents	—	(92.0)	—	—	(92.0)
Cash and cash equivalents at beginning of period	—	134.5	—	—	134.5
Cash and cash equivalents at end of period	$ —	$ 42.5	$ —	$ —	$ 42.5

	Year Ended December 31, 2013				
	Parent	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
			(*Millions of dollars*)		
Operating activities					
Cash provided by operating activities	$ 870.7	$ 65.1	$ 981.6	$ (909.7)	$ 1,007.7
Investing activities					
Capital expenditures	—	(2.6)	(1,936.7)	—	(1,939.3)
Other investing activities	—	(11.4)	(375.4)	—	(386.8)
Cash provided by (used in) investing activities	—	(14.0)	(2,312.1)	—	(2,326.1)
Financing activities					
Cash distributions:					
General and limited partners	(909.7)	(909.7)	—	909.7	(909.7)
Noncontrolling interests	—	—	(0.6)	—	(0.6)
Intercompany borrowings (advances), net	(1,794.8)	456.0	1,338.8	—	—
Issuance of long-term debt, net of discounts	1,247.8	—	—	—	1,247.8
Debt financing costs	(10.2)	—	—	—	(10.2)
Repayment of long-term debt	—	—	(7.7)	—	(7.7)
Issuance of common units, net of issuance costs	583.9	—	—	—	583.9
Contribution from general partner	12.3	—	—	—	12.3
Cash provided by (used in) financing activities	(870.7)	(453.7)	1,330.5	909.7	915.8
Change in cash and cash equivalents	—	(402.6)	—	—	(402.6)
Cash and cash equivalents at beginning of period	—	537.1	—	—	537.1
Cash and cash equivalents at end of period	$ —	$ 134.5	$ —	$ —	$ 134.5

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

The Chief Executive Officer (Principal Executive Officer) and the Chief Financial Officer (Principal Financial Officer) of ONEOK Partners GP, our general partner, who are the equivalent of our principal executive and principal financial officers, respectively, have concluded that our disclosure controls and procedures were effective as of the end of the period covered by this report based on the evaluation of the controls and procedures required by Rule 13a-15(b) of the Exchange Act.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including our Principal Executive Officer and Principal Financial Officer, we evaluated the effectiveness of our internal control over financial reporting based on the framework in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Based on our evaluation under that framework and applicable SEC rules, our management concluded that our internal control over financial reporting was effective as of December 31, 2015.

The effectiveness of our internal control over financial reporting as of December 31, 2015, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report that is included herein (Item 8).

Changes in Internal Controls Over Financial Reporting

There have been no changes in our internal controls over financial reporting during the quarter ended December 31, 2015, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Board of Directors of our General Partner

We are managed under the direction of the Board of Directors of our sole general partner, ONEOK Partners GP, which consists of eight members appointed by ONEOK, the parent corporation of our general partner. We refer to the Board of Directors of ONEOK Partners GP as our Board of Directors. Because the members of our Board of Directors are not elected by unitholders, we do not have a procedure by which security holders may recommend nominees to our Board of Directors.

Because we are a limited partnership and meet the definition of a "controlled company" under the listing standards of the NYSE, certain listing standards of the NYSE are not applicable to us. Accordingly, Section 303A.01 of the NYSE Listed Company Manual, which would require that the Board of Directors of our general partner be comprised of a majority of independent directors, and Sections 303A.04 and 303A.05 of the NYSE Listed Company Manual, which would require that the Board of Directors of our general partner maintain a nominating committee and a compensation committee, each consisting entirely of independent directors, are not applicable to us. However, our Board of Directors has affirmatively determined that six of the eight members of our Board of Directors, Julie H. Edwards, Steven J. Malcolm, Jim W. Mogg, Gary N. Petersen, Craig F. Strehl and Michael G. Hutchinson, have no material relationship with us and are "independent" under our Governance Guidelines and the listing standards of the NYSE.

In evaluating candidates for appointment to our Board of Directors, ONEOK considers factors that are in the best interests of the Partnership and its unitholders, including the knowledge, experience, integrity and judgment of each candidate; the potential contribution of each candidate to the diversity of backgrounds, experience and competencies that ONEOK desires to have represented on the Board; each candidate's ability to devote sufficient time and effort to his or her duties as a director; and any core competencies or technical expertise necessary for the Board and to staff Board committees. In addition, ONEOK assesses whether a candidate possesses the integrity, judgment, knowledge, experience, skills and expertise that are likely to enhance the Board's ability to manage and direct the affairs and business of the Partnership.

ONEOK believes that each member of our Board possesses the necessary integrity, skills, knowledge, judgment, expertise and experience to serve on our Board, and that their individual and collective skills and qualifications provide them the ability to engage management and each other in a constructive and collaborative fashion and, when necessary and appropriate, challenge management in the execution of our business operations and strategy.

Our Board of Directors is led by John W. Gibson, the Chairman of the Board. In addition, our Audit Committee and Conflicts Committee are each led by an independent chair and vice chair. We do not have a lead independent director. The Board believes this leadership structure enables our Board to take advantage of the leadership skills of both Mr. Gibson and the chairs and vice chairs of our Audit and Conflicts Committees, and provides a structure for strong independent oversight of our management.

The Audit Committee

Our Board of Directors has appointed an Audit Committee consisting of the six members of our Board of Directors who are independent under our Governance Guidelines and the listing standards of the NYSE. Our guidelines for determining the independence of members of the Audit Committee are included in our Governance Guidelines and provide that members of the Audit Committee shall at all times qualify as independent under the listing standards of the NYSE and the applicable rules of the SEC and other applicable laws. At least annually, the Board of Directors reviews the relationships of each Audit Committee member with us to affirmatively determine the independence of each member. In February 2016, our Board of Directors affirmatively determined that Ms. Edwards and Messrs. Hutchinson, Malcolm, Mogg, Petersen, and Strehl meet the standards for independence set forth in our Governance Guidelines and are independent.

Our Board of Directors annually reviews the financial expertise of the members of our Audit Committee. In February 2016, our Board of Directors determined that Ms. Edwards and Messrs. Hutchinson, Malcolm, Mogg, Petersen, and Strehl are each "audit committee financial experts," as defined by the rules of the SEC.

The Audit Committee has oversight responsibility with respect to the integrity of our financial statements, the performance of our internal audit function, the independent auditor's qualifications and independence and our compliance with legal and regulatory requirements. The Audit Committee directly appoints, retains, evaluates and may terminate our independent auditor. The Audit Committee reviews our annual audited and quarterly unaudited financial statements. The Audit Committee has all other responsibilities required by the applicable NYSE listing standards and applicable rules of the SEC. Our Board of Directors has adopted a written charter for our Audit Committee, which is available on and may be printed from our website at www.oneokpartners.com and is also available from the secretary of ONEOK Partners GP upon request.

The Conflicts Committee

Our Board of Directors has appointed a Conflicts Committee consisting of the three members of our Board of Directors who are independent under our Governance Guidelines and the listing standards of the NYSE and who are not also executive officers or members of the Board of Directors of ONEOK. The Conflicts Committee has the authority to review specific matters that may present a conflict of interest in order to determine if the resolution of such conflict is "fair and reasonable" to our unitholders. In making any such determination, the Conflicts Committee has the authority to engage advisors to assist it in carrying out its duties.

Risk Oversight

We engage in an annual comprehensive enterprise risk-management (ERM) process to aggregate, monitor, measure and manage risk. Our ERM approach is designed to enable our Board of Directors to establish a mutual understanding with management of the effectiveness of our risk-management practices and capabilities, to review our risk exposure and to elevate certain key risks for discussion at the Board level. Our ERM program is overseen by our Chief Financial Officer. Management and our Board of Directors believe that risk management is an integral part of our annual strategic planning process, which addresses, among other things, the risks and opportunities facing our company.

Our ERM program is an entitywide process designed to identify, assess and manage risks that could affect our ability to fulfill our business objectives or execute our business strategies. Our ERM process involves the identification and assessment of a broad range of risks and the development of plans to mitigate their effects. These risks generally relate to strategic, operational, financial, regulatory compliance and human resources issues.

Not all risks can be dealt with in the same way. Some risks may be easily perceived and controllable, and other risks are unknown; some risks can be avoided or mitigated by particular behavior, and some risks are unavoidable as a practical matter. For some risks, the potential adverse impact would be minor, and, as a matter of business judgment, it may not be appropriate to allocate significant resources to avoid the adverse impact. In other cases, the adverse impact could be significant, and it is prudent to expend resources to seek to avoid or mitigate the potential adverse impact. In some cases, a higher degree of risk may be acceptable because of a greater perceived potential for reward. Management is responsible for identifying risks and risk controls related to our significant business activities, mapping the risks to our partnership strategies, and developing programs and recommendations to determine the sufficiency of risk identification, the balance of potential risk to potential reward, and the appropriate manner in which to control and mitigate risk.

Our Board of Directors implements its risk oversight responsibilities by having management provide periodic briefing and informational sessions on the significant voluntary and involuntary risks that the Partnership faces and how the Partnership is seeking to control and mitigate these risks if and when appropriate. In some cases, as with risks relating to significant acquisitions, risk oversight is addressed as part of the full Board's engagement with the Chief Executive Officer and management.

Our Board of Directors annually reviews a management assessment of the various operational and regulatory risks facing the Partnership, their relative magnitude and management's plan for mitigating these risks.

We also maintain a Risk Oversight and Strategy Committee, which is established by our senior management. This committee is responsible for ensuring that exposure to commodity, currency and interest-rate risk, as well as marketing, trading and hedging practices, are monitored within the framework established by our policies. The committee also is responsible for ensuring that marketing and hedging strategies are developed and implemented to mitigate or manage those risks within acceptable risk thresholds.

Our Audit Committee oversees risk issues associated with our overall financial reporting and disclosure process and legal compliance, as well as reviews policies and procedures on risk control assessment and accounting risk exposure, including our business continuity and disaster recovery plans. The Audit Committee meets with our Chief Financial Officer, General Counsel and Vice President - Audit Services, as well as our independent registered public accounting firm, in executive sessions to discuss risk issues at each of its in-person meetings during the year.

Directors and Executive Officers

The following table sets forth the members of our Board of Directors, Audit Committee, Conflicts Committee and our executive officers. The persons designated as our executive officers serve in that capacity at the discretion of our Board of Directors. There are no family relationships between any of our executive officers or members of the Board of Directors, Audit Committee or the Conflicts Committee.

Name	Age	Position
John W. Gibson	63	Chairman of the Board
Terry K. Spencer	56	President, Chief Executive Officer and Member, Board of Directors
Derek S. Reiners	44	Senior Vice President, Chief Financial Officer and Treasurer
Robert F. Martinovich	58	Executive Vice President and Chief Administrative Officer
Walter S. Hulse III	52	Executive Vice President, Strategic Planning and Corporate Affairs
Stephen W. Lake	52	Senior Vice President, General Counsel and Assistant Secretary
Wesley J. Christensen	62	Senior Vice President, Operations
Sheppard F. Miers III	47	Vice President and Chief Accounting Officer
Julie H. Edwards	57	Member, Board of Directors and Audit Committee
Michael G. Hutchinson	60	Member, Board of Directors and Vice Chairman, Audit and Conflicts Committees
Steven J. Malcolm	67	Member, Board of Directors and Audit Committee
Jim W. Mogg	67	Member, Board of Directors and Audit Committee
Gary N. Petersen	64	Member, Board of Directors, Audit and Conflicts Committees
Craig F. Strehl	58	Member, Board of Directors and Chairman, Audit and Conflicts Committees

John W. Gibson is nonexecutive Chairman of the Board of ONEOK Partners GP and ONEOK. He served as our Chairman of the Board and Chief Executive Officer from 2007 until January 31, 2014, and also served as President from 2010 through 2011. From 2007 until January 31, 2014, he served as the Chief Executive Officer of ONEOK and was appointed Chairman of the ONEOK Board in May 2011. He also served as the President of ONEOK from 2010 through 2011. From 2005 until May 2006, he was President of ONEOK Energy Companies, which included ONEOK's gathering and processing, natural gas liquids, pipelines, and storage and energy services business segments. Prior to that, he was ONEOK's President, Energy, from May 2000 to 2005. Mr. Gibson joined ONEOK in May 2000 from Koch Energy, Inc., a subsidiary of Koch Industries, where he was an Executive Vice President. His career in the energy industry began in 1974 as a refinery engineer with Exxon USA. He spent 18 years with Phillips Petroleum Company in a variety of domestic and international positions in its natural gas, natural gas liquids and exploration and production businesses, including Vice President of Marketing of its natural gas subsidiary GPM Gas Corp. Mr. Gibson serves on the Board of Directors of ONE Gas, Inc. and BOK Financial Corporation and the Board of Trustees of Missouri University of Science and Technology.

Mr. Gibson has served in a variety of roles of continually increasing responsibility at ONEOK Partners GP since 2004, ONEOK since 2000, and prior to 2000, at Koch Energy, Inc., Exxon USA, and Phillips Petroleum. In these roles, Mr. Gibson has had direct responsibility for and extensive experience in strategic and financial planning, acquisitions and divestitures, operations, management supervision and development, and compliance. As the executive responsible for numerous merger-and-acquisition transactions over the course of his career, Mr. Gibson has significant experience in assessing merger-and-acquisition opportunities, and in structuring, financing and completing merger-and-acquisition transactions. Over the course of his lengthy career in a variety of sectors of the oil and gas industry, Mr. Gibson has gained extensive management and operational experience and has demonstrated a strong record of leadership, strategic vision and risk management. In light of Mr. Gibson's prior role as the top executive officer of our general partner and his extensive industry and managerial experience and knowledge, ONEOK has concluded that Mr. Gibson should continue as a member of our Board of Directors.

Terry K. Spencer was appointed to the Board of Directors in January 2010. Mr. Spencer was appointed President and Chief Executive Officer of both ONEOK Partners GP and ONEOK, effective January 31, 2014, and was appointed President of ONEOK Partners GP and ONEOK, effective January 1, 2012. He served as our Chief Operating Officer from July 16, 2009, through December 31, 2011. From 2007, until his appointment as Chief Operating Officer, Mr. Spencer served as our Executive Vice President – Natural Gas Liquids. Mr. Spencer previously served as President – Natural Gas Liquids from April 2006 and served as Senior Vice President – Natural Gas Liquids from July 2005 to March 2006 following the asset acquisition from Koch Energy, Inc. From 2003 to 2005, he served as Vice President and General Manager of Gas Supply and Project Development for ONEOK. Prior to joining the Partnership and ONEOK, he held position of increasing responsibility in the natural gas gathering and processing industry with Continental Natural Gas, Inc., in Tulsa; Stellar Gas Company in Houston; and Texas Oil and Gas Corporation's Delhi Gas Pipeline subsidiary in Dallas. Mr. Spencer is a member of the Gas Processors Association Board of Directors and its executive and finance committees.

Mr. Spencer has extensive senior management experience in the oil and natural gas industry as a result of his service in a variety of roles of continually increasing responsibility at both the Partnership and ONEOK since 2003. In these roles, Mr. Spencer has had direct responsibility for, and extensive experience in, strategic and financial planning, acquisitions and divestitures, operations, management supervision and development, and compliance. Mr. Spencer has significant experience in assessing acquisition opportunities and in structuring, financing and completing merger and acquisition transactions. During the course of his lengthy career in a variety of sectors in the oil and natural gas industry, Mr. Spencer has gained extensive management and operational experience and has demonstrated a strong record of achievement and sound judgment. In light of Mr. Spencer's extensive industry and executive managerial experience, ONEOK has concluded that Mr. Spencer should continue as a member of our Board of Directors.

Derek S. Reiners was appointed Senior Vice President, Chief Financial Officer and Treasurer of ONEOK Partners GP and ONEOK, effective January 1, 2013. He served as Senior Vice President and Chief Accounting Officer of ONEOK Partners GP and ONEOK from August 2009 through December 31, 2012. Prior to joining ONEOK, Mr. Reiners was a partner of the accounting firm Grant Thornton LLP since 2004, where he served clients primarily in the energy industry. Mr. Reiners also serves as a member of the Audit and Management Committees of Northern Border Pipeline Company and a member of the management committee of Roadrunner Gas Transmission. Mr. Reiners is a certified public accountant.

Robert F. Martinovich was appointed Executive Vice President and Chief Administrative Officer, effective February 20, 2015. Prior to that, he was Executive Vice President, Commercial, of ONEOK Partners GP and ONEOK since January 31, 2014. Mr. Martinovich served as Executive Vice President, Operations, of ONEOK Partners GP and ONEOK from January 1, 2013 to January 31, 2014, and as Executive Vice President, Chief Financial Officer and Treasurer of ONEOK Partners GP and ONEOK from January 1, 2012, through December 31, 2012. He served as our Senior Vice President, Chief Financial Officer and Treasurer from March 1, 2011, through December 31, 2011. He served as a member of the Board of Directors from March 1, 2011, through December 31, 2012. He served as ONEOK's chief operating officer from July 2009 through February 2011, responsible for ONEOK's Distribution and Energy Services operating segments. He joined ONEOK in 2007 as President of our Natural Gas Gathering and Processing segment. Prior to joining ONEOK, he held a variety of executive management positions for DCP Midstream, LLC after joining the company in 2000. Previously, he was Senior Vice President of GPM Gas Corporation, the natural gas gathering, processing and marketing division of Phillips Petroleum Company, holding a variety of marketing, financial and operational leadership roles. Mr. Martinovich joined Phillips in 1980 and held various engineering, sales and marketing positions in the research and development and the plastics divisions of Phillips, and also served on the company's corporate planning and development staff.

Walter S. Hulse III was appointed Executive Vice President, Strategic Planning and Corporate Affairs, effective February 2015. Mr. Hulse is a veteran of the financial industry with more than 29 years of experience in investment banking. Mr. Hulse joined ONEOK from Spinnaker Strategic Advisory Services, LLC, which provides consulting services to mid-cap and large-cap publicly traded companies, including the review of merger and/or acquisition opportunities, debt and equity markets, corporate restructuring and potential divestitures. Mr. Hulse has served us as a consultant to ONEOK for many years and most recently assisted with the separation of ONE Gas. Mr. Hulse has served as Vice Chairman of the Investment Banking Department, Managing Director and Head of the Business Development Group and Head of the Global Utility Group at UBS Investment Bank. Before joining UBS Investment Bank at the time of its merger with PaineWebber Incorporated, Mr. Hulse was the Director of the Mergers and Acquisition Department at PaineWebber. Before rejoining Paine Webber in 2000, Mr. Hulse was Managing Director and Co-head of Global Energy and Power M&A at JP Morgan Securities, Inc. From 1997 to mid-1999, Mr. Hulse was Head of the Utility Finance Group at PaineWebber. From 1994 to 1996, Mr. Hulse was Managing Director and Head of the Fixed Income Capital Markets Group at PaineWebber.

Stephen W. Lake was appointed Senior Vice President, General Counsel and Assistant Secretary of ONEOK Partners GP and ONEOK, effective January 1, 2012. Mr. Lake was Senior Vice President, Associate General Counsel and Assistant Secretary of

ONEOK Partners GP and ONEOK from July 1, 2011, to December 31, 2011. Mr. Lake had served previously as Executive Vice President and General Counsel at McJunkin Red Man Corporation (MRC) since October 2008 and had served as Senior Vice President and General Counsel from January 2008 to October 2008. Before joining MRC, Mr. Lake was a shareholder at Tulsa-based law firm, Gable & Gotwals, a Professional Corporation. Mr. Lake became a Gable & Gotwals shareholder in January 1998 and served on the firm's board of directors from January 2005 until joining MRC.

Wesley J. Christensen was appointed Senior Vice President, Operations, of ONEOK Partners, effective September 21, 2011. Mr. Christensen previously served as Senior Vice President of Natural Gas Liquids operations of ONEOK Partners from 2007 to 2011. Prior to ONEOK's acquisition of Koch Industries' natural gas assets in 2005, he was Vice President, Operations, of Koch Pipeline Company, L.P. He also held various positions with Koch Hydrocarbon Company in Medford, Oklahoma, and in Sidney, Montana, where he began his career in 1980.

Sheppard F. Miers III was appointed our Vice President and Chief Accounting Officer, effective January 1, 2013. He served as our Vice President and Controller from July 2009 through December 31, 2012. Mr. Miers was Vice President of Audit, Business Process Improvement and Business Development of ONEOK from 2005 through July 2009. Mr. Miers is chairman of the Audit Committee of Northern Border Pipeline Company. Mr. Miers is a certified public accountant.

Julie H. Edwards was appointed to our Board of Directors in August 2009. Ms. Edwards also serves on the Board of Directors of ONEOK and is chair of the ONEOK Audit Committee and a member of the ONEOK Executive Committee Ms. Edwards retired in 2007 from Southern Union Company where she served as Senior Vice President-Corporate Development from November 2006 to January 2007 and as Senior Vice President and Chief Financial Officer from July 2005 to November 2006. Prior to June 2005, she was an executive officer of Frontier Oil Corporation, having served as Chief Financial Officer from 1994 to 2005 and as Treasurer from 1991 to 1994. Prior to joining Frontier Oil Corporation in 1991, Ms. Edwards was an investment banker with Smith Barney, Harris, Upham & Co., Inc. in New York and Houston, after joining the company as an associate in 1985, when she graduated from the Wharton School of the University of Pennsylvania with an M.B.A. Prior to attending Wharton, she worked as an exploration geologist in the oil industry, having earned a Bachelor of Science in Geology and Geophysics from Yale University in 1980.

Ms. Edwards is also a member of the Board of Directors of Noble Corporation, a U.K.-based offshore drilling contractor. She was a member of the Board of Directors of NATCO Group, Inc., an oil field services and equipment manufacturing company, from 2004 until its sale to Cameron International Corporation in November 2009.

In addition to her experience from service on the boards of directors of several public companies, Ms. Edwards brings to our Board broad experience and understanding of various segments within the energy industry (exploration and production, refining and marketing, natural gas transmission, processing and distribution, production technology and contract drilling), and significant senior accounting, finance, capital markets, corporate development and management experience and expertise. In light of Ms. Edwards' extensive industry and executive managerial and financial experience and knowledge, ONEOK has concluded that Ms. Edwards should continue as a member of our Board of Directors.

Michael G. Hutchinson was appointed to our Board of Directors on April 16, 2015. Mr. Hutchinson has served on the Board of Directors of Westmoreland Coal Company since 2012 and is chairman of its Audit Committee and a member of its Compensation Committee. Mr. Hutchinson also has served on the Board of Directors of ONE Gas, Inc. since 2014 and is chairman of its Audit Committee, vice chair of its Corporate Governance Committee and a member of its Executive Compensation Committee.

Mr. Hutchinson retired as a partner from Deloitte & Touche in 2012. His Deloitte career spanned nearly 35 years, leading the energy and natural resources practice in Colorado for more than 10 years, while at the same time managing more than 150 professionals in the Denver audit and enterprise risk-management practice.

As a former partner of Deloitte & Touche, Mr. Hutchinson has extensive experience with complex financial and accounting and internal control issues, as well as significant accounting and governance experience related to his current and past responsibilities as chairman of the audit committee of other publicly traded companies. During his tenure on our Board of Directors and the Audit Committee, Mr. Hutchinson has also developed significant knowledge of the critical accounting, operational and financial issues facing our company and our industry. In light of Mr. Hutchinson's extensive industry, finance and accounting experience and knowledge, ONEOK has concluded that Mr. Hutchinson should continue as a member of our Board of Directors.

Steven J. Malcolm was appointed to our Board of Directors on January 1, 2012. Mr. Malcolm also serves on the Board of ONEOK and is chair of the ONEOK Executive Compensation Committee and a member of the ONEOK Executive Committee.

Mr. Malcolm served as President of The Williams Companies, Inc. from September 2001 until January 2011, Chief Executive Officer of Williams from January 2002 to January 2011, and Chairman of the Board of Directors of Williams from May 2002 to January 2011. Mr. Malcolm served as Chairman of the Board and Chief Executive Officer of Williams Partners GP LLC, the general partner of Williams Partners L.P., from 2005 to January 2011.

Mr. Malcolm began his career at Cities Service Company in refining, marketing, and transportation services in 1970. Mr. Malcolm joined Williams in 1984 and performed roles of increasing responsibility related to business development, gas management and supply, and gathering and processing. Mr. Malcolm was Senior Vice President and General Manager of Williams Field Services Company, a subsidiary of Williams, from 1994 to 1998. He was President and Chief Executive Officer of Williams Energy Services, LLC, a subsidiary of Williams, from 1998 to 2001. He was Executive Vice President of Williams from May 2001 to September 2001 and Chief Operating Officer of Williams from September 2001 to January 2002. Mr. Malcolm was also a director of Williams Partners GP LLC and Williams Pipeline GP LLC, the general partner of Williams Pipeline Partners L.P.

Mr. Malcolm currently serves as a director of BOK Financial Corporation. Mr. Malcolm also serves on the boards of the YMCA of Greater Tulsa, the YMCA of the USA, the Oklahoma Center for Community and Justice, the University of Tulsa Board of Trustees and the Missouri University of Science and Technology Board of Trustees. In light of Mr. Malcolm's extensive industry, financial, corporate governance, public policy and government, operating, and compensation experience, and strong record of leadership and strategic vision, ONEOK has concluded that Mr. Malcolm should continue as a member of our Board of Directors.

Jim W. Mogg was appointed to our Board of Directors in August 2009. Mr. Mogg also serves on the Board of Directors of ONEOK and is chair of the ONEOK Corporate Governance Committee and a member of the ONEOK Executive Committee. Mr. Mogg served as Chairman of the Board of DCP Midstream GP, LLC, the general partner of DCP Midstream Partners, L.P. from August 2005 to April 2007. In addition to presiding over board meetings and providing strategic oversight, he was involved in launching DCP Midstream Partners as a public company. From January 2004 to September 2006, Mr. Mogg served as Group Vice President, Chief Development Officer and advisor to the Chairman of Duke Energy Corporation and, in that capacity, was responsible for the merger and acquisition, strategic planning and human resources activities of Duke Energy. Additionally, Duke Energy affiliates, Crescent Resources and TEPPCO Partners, LP (TEPPCO Partners) reported to Mr. Mogg and he was the executive sponsor of Duke Energy's Finance and Risk Management Committee of the Board of Directors. Mr. Mogg served as President and Chief Executive Officer of DCP Midstream, LLC from December 1994 to March 2000, and as Chairman, President and Chief Executive Officer from April 2000 through December 2003. Under Mr. Mogg's leadership, DCP Midstream became the nation's largest producer of natural gas liquids and one of the largest gatherers and processors of natural gas. DCP Midstream achieved this significant growth via acquisitions, construction and optimization of assets. DCP Midstream was the general partner of TEPPCO Partners and, as a result, Mr. Mogg was Vice Chairman of TEPPCO Partners from April 2000 to May 2002 and Chairman from May 2002 to February 2005. Mr. Mogg serves on the Board of Directors of Bill Barrett Corporation, where he is currently the nonexecutive Chairman of the Board, and serves on the Board of Directors of Matrix Service Company.

Mr. Mogg has extensive senior management experience in a variety of sectors in the oil and natural gas industry as a result of his service at DCP Midstream and Duke Energy where he demonstrated a strong record of achievement and sound judgment. As the executive responsible for numerous merger-and-acquisition transactions at DCP Midstream, TEPPCO Partners and Duke Energy, he has significant experience in assessing acquisition opportunities and in structuring, financing and completing merger-and-acquisition transactions. In addition, Mr. Mogg's current and previous directorships at other companies, including publicly traded master limited partnerships, provide him with extensive corporate and master limited partnership governance experience. As a result of his experience, Mr. Mogg is qualified to analyze the various financial and operational aspects of the Partnership. In light of Mr. Mogg's extensive industry and executive managerial experience and knowledge, ONEOK has concluded that Mr. Mogg should continue as a member of our Board of Directors.

Gary N. Petersen was appointed to our Board of Directors in May 2006. From May 2011 to November 2014, Mr. Petersen served as President of Energy Technology Unlimited of Minnesota, LLC, a start-up antifreeze recycling company based in Faribault, Minnesota. Mr. Petersen retired in July 2010 as President of Endres Processing LLC, a recycler and processor of food waste into livestock feed ingredients, where he was responsible for strategic planning, merger/acquisitions, financial analysis, budgets and forecasts, and management development. He provided consulting services to Endres Processing until February 2012.

Additionally, Mr. Petersen has been a consultant for the past 15 years to a number of small businesses and not-for-profit organizations. His consulting work with senior management includes facilitation of strategic thinking and planning processes, business acquisitions and sales, feasibility studies, financial reporting and analysis, organizational development and crisis management.

From 1977 to 1998, Mr. Petersen was employed by Reliant Energy-Minnegasco and served as President and Chief Operating Officer of Reliant Energy-Minnegasco, from 1991 to 1998 where he directed Minnegasco's operations. The first 10 years of his Minnegasco career included numerous management positions of increasing responsibility in state utility regulation, gas supply procurement, strategic planning, financial reporting and analysis, mergers and acquisitions and rate case preparation and expert testimony. Prior to his employment at Minnegasco, Mr. Petersen was a senior auditor with Arthur Andersen & Co. He currently serves on the board of the Dunwoody College of Technology and as Chairman of the Board of Directors of Micro-Matics, Inc., Fridley, Minnesota.

Mr. Petersen has broad senior management, accounting and financial experience in the oil and gas industry as a result of his service at Reliant Energy-Minnegasco, as well as extensive senior management experience as a result of his service at Endres Processing LLC, where he has demonstrated a strong record of achievement and sound judgment. In light of Mr. Petersen's extensive industry and executive managerial and financial experience and knowledge, ONEOK has concluded that Mr. Petersen should continue as a member of our Board of Directors.

Craig F. Strehl was appointed to our Board of Directors in August 2009. Mr. Strehl is a former independent director of LONESTAR Midstream Partners, LP. Prior to his affiliation with LONESTAR, Mr. Strehl was the President of Sid Richardson Carbon & Energy Company, a private natural gas midstream and chemical manufacturing company, where he managed significant growth through approximately $200 million in acquisitions and numerous internal capital projects. In 2006, he led the sale of the midstream business to Southern Union Company for $1.6 billion. He then served as President of Southern Union Company's midstream assets until he retired in January 2007.

Mr. Strehl began his energy career in 1980 with TXO, where he served in various engineering positions related to the construction, operation and acquisition of gas pipeline and gas processing facilities. He later served in various commercial capacities at TXO. He left TXO in 1987 to join Aquila Energy. As Vice President of Marketing and Business Development for Aquila, he completed the purchase of Clajon Gas Company in 1990, which was subsequently renamed Aquila Gas Pipeline Corporation in 1993. As Chief Executive Officer of Aquila Gas Pipeline, he led the company's initial public offering in 1993. During his tenure as Chief Operating Officer of Aquila Gas Pipeline, Mr. Strehl managed all investor and rating agency relations and was responsible for all filings with the SEC.

Mr. Strehl has extensive senior management experience in a variety of sectors in the oil and gas industry as a result of his service at LONESTAR Midstream Partners, LP, LONESTAR Midstream Partners II, LP, Sid Richardson Carbon & Energy Company, Southern Union Company and Aquila Gas Pipeline where he has demonstrated a strong record of achievement and sound judgment. In light of Mr. Strehl's extensive industry and executive managerial experience and knowledge, ONEOK has concluded that Mr. Strehl should continue as a member of our Board of Directors.

Director Compensation

Compensation for our nonmanagement directors for the year ended December 31, 2015, consisted of an annual cash retainer of $150,000. In addition, the chair of our Audit Committee received an additional annual cash retainer of $10,000 and the Chairman of the Board received an additional annual cash retainer of $25,000. Nonmanagement directors are reimbursed for their expenses related to their attendance at Board of Directors, Audit Committee and Conflicts Committee meetings. A director who is also an officer or employee of ONEOK Partners GP or ONEOK receives no compensation for his or her service as a director.

With respect to any month during which the Conflicts Committee of the Board of Directors, or any other committee established by the Board of Directors, including any other committee established in accordance with the Partnership Agreement, is conducting a review of one or more transactions involving an actual or potential conflict of interest for the purpose of "special approval," the members of the Conflicts Committee or such other committee are compensated as follows: a cash retainer of $10,000 per month, up to $80,000 annually, is paid to the chair of the Conflicts Committee, and a cash retainer of $7,500 per month, up to $60,000 annually, is paid to the other members of the Conflicts Committee.

The following table sets forth the compensation paid to our nonmanagement directors in 2015.

2015 DIRECTOR COMPENSATION

Name	Fees Earned or Paid in Cash ($)	Stock Awards ($)	Option Awards ($)	Non Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation (1) ($)	Total ($)
John W. Gibson	$ 175,000	—	—	—	—	—	$ 175,000
Julie H. Edwards	$ 150,000	—	—	—	—	—	$ 150,000
Michael G. Hutchinson (2)	$ 113,750	—	—	—	—	300	$ 114,050
Steven J. Malcolm	$ 150,000	—	—	—	—	—	$ 150,000
Jim W. Mogg	$ 150,000	—	—	—	—	—	$ 150,000
Gary N. Petersen	$ 157,500	—	—	—	—	300	$ 157,800
Craig F. Strehl (3)	$ 167,194	—	—	—	—	300	$ 167,494
Gil Van Lunsen (4)	$ 44,889	—	—	—	—	10,300	$ 55,189

(1) For Messrs. Hutchinson, Petersen, Strehl and Van Lunsen, reflects charitable contributions made by ONEOK or the ONEOK Foundation, Inc. on their behalf as follows: (a) a $300 annual contribution to the nonprofit organization of his choice; (b) matching contributions up to $5,000 per year to nonprofit organizations of his choice pursuant to our Board matching grant program; (c) for a retiring member of the Board, a one-time contribution of $10,000 to the nonprofit organization of his choice, and (d) matching contributions to the United Way pursuant to our annual United Way contribution program. For the remaining members of the Board, does not reflect charitable contributions made by ONEOK or the ONEOK Foundation, Inc. on their behalf as these amounts will be included in the Non-Management Director Compensation Table in the ONEOK 2016 Proxy Statement when filed with the SEC as follows: Mr. Gibson, $23,000; Ms. Edwards, $300; Mr. Malcolm, $25,300; and Mr. Mogg, $5,300.
(2) Mr. Hutchinson joined our Board on April 16, 2015, and his compensation was prorated for his term of service in 2015.
(3) Mr. Strehl became chair of our Audit Committee on April 11, 2015, and his retainer for that position was prorated for his term of service in 2015.
(4) Mr. Van Lunsen retired from our Board on April 11, 2015.

Additional Governance Matters

Executive Sessions of the Board and the Audit Committee - Our Board of Directors holds regular executive sessions during which nonmanagement board members meet without any members of management present and during which the independent directors meet at each in-person meeting of the Board. The chairman of our Audit Committee presides at regular sessions of the independent members of our Board of Directors. The Audit Committee also meets in executive session without management present at each in-person meeting of the Audit Committee.

Governance Guidelines - Our Board of Directors has adopted Governance Guidelines that address several Partnership governance matters, including responsibilities of our directors, the composition and responsibility of the Audit Committee, the conduct and frequency of board meetings, management succession, director access to management and outside advisors, director orientation and continuing education, and the annual self-evaluation of the board. Our Board of Directors recognizes that effective governance is an ongoing process, and the Board reviews our Governance Guidelines periodically as deemed necessary.

Code of Business Conduct and Ethics - Our Board of Directors has adopted a Code of Business Conduct and Ethics applicable to the members of our Board of Directors, our officers and the employees of ONEOK, ONEOK Partners GP and ONEOK Services Company, who provide services to us. This code sets out our requirements for compliance with legal and ethical standards in the conduct of our business, including general business principles, legal and ethical obligations, compliance policies for specific subjects, reporting of compliance issues and discipline for violations of the code. We intend to promptly post on our website any amendments to, or waivers from (including any implicit waiver), any provision of our Code of Business Conduct and Ethics in accordance with the applicable rules of the SEC and NYSE.

Web Access - We provide access through our website at www.oneokpartners.com to current information relating to Partnership governance, including our Audit Committee Charter, our Code of Business Conduct and Ethics, our Governance Guidelines and other matters impacting our governance principles. You may access copies of each of these documents from our website. You may also contact the office of the secretary of ONEOK Partners GP for printed copies of these documents free of charge. Our website and any contents thereof are not incorporated by reference into this document.

Communications with Directors - Our Board of Directors believes that it is management's role to speak for the Partnership. Our Board of Directors also believes that any communications between members of the Board of Directors and interested parties, including unitholders, should be conducted with the knowledge of our chairman of the board and our chief executive officer. Interested parties, including unitholders, may contact one or more members of our Board of Directors, including nonmanagement directors and nonmanagement directors as a group, by writing to the director or directors in care of the secretary of ONEOK Partners GP at our principal executive offices. A communication received from an interested party or unitholder will be promptly forwarded to the director or directors to whom the communication is addressed. A copy of the communication also will be provided to our chairman of the board and our chief executive officer. We will not, however, forward sales or marketing materials or correspondence primarily commercial in nature, materials that are abusive, threatening or otherwise inappropriate, or correspondence not clearly identified as interested party or unitholder correspondence.

Compensation Committee Interlocks and Insider Participation - We do not have a compensation committee. During 2015, the compensation of our named executive officers was determined by ONEOK's Executive Compensation Committee, which consists of independent members of the ONEOK Board of Directors. No member of ONEOK's Executive Compensation Committee is, or was formerly, an officer or employee of ONEOK, ONEOK Partners GP or any of their subsidiaries.

Section 16(a) Beneficial Ownership Reporting Compliance - Section 16(a) of the Exchange Act requires executive officers, members of our Board of Directors and persons who own more than 10 percent of our common units to file reports of ownership and changes in ownership with the SEC and the NYSE and to furnish us with copies of all Section 16(a) forms they file. Based solely on our review of the copies of such forms received by us during and with respect to the 2015 fiscal year or written representations from certain reporting persons that no Form 5s were required for those persons, we believe that during 2015 our reporting persons complied with all applicable filing requirements in a timely manner.

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

We do not employ directly any of the persons responsible for managing or operating our business. Instead, we are managed by our general partner, ONEOK Partners GP, the executive officers of which are employees of ONEOK.

We do not have a compensation committee. The compensation of the officers of our general partner, who are deemed to be our officers, is set by the Executive Compensation Committee of the Board of Directors of ONEOK. A discussion of the objectives of, and other matters related to, ONEOK's compensation programs will be included in the Executive Compensation Discussion and Analysis section of ONEOK's 2016 Proxy Statement when filed with the SEC (ONEOK 2016 Proxy Statement), which is incorporated herein by this reference. A copy of the ONEOK 2016 Proxy Statement will be provided on, and may be copied from, ONEOK's website at www.oneok.com and is available free of charge from the secretary of ONEOK Partners GP upon request.

We have a Services Agreement with ONEOK under which a portion of the compensation paid by ONEOK to our named executive officers is allocated to us and reimbursed by us to ONEOK. The compensation amounts shown in the following table represent that portion of the named executive officer's total compensation that is allocated to and reimbursed by us under the Services Agreement. Please read "Certain Relationships and Related Person Transactions, and Director Independence-Services Agreement" for a description of the Services Agreement.

The following table summarizes the compensation allocated to and reimbursed by us in 2015 for our principal executive officer, principal financial officer and the three other most highly compensated executive officers (which we collectively refer to as the "named executive officers") of our general partner, ONEOK Partners GP.

Summary Compensation Table for 2015

Name and Principal Position	Year		Salary		Stock Awards (1)		Non-Equity Incentive Plan Compensation (2)		Change in Pension Value and Nonqualified Deferred Compensation Earnings (3)		All Other Compensation (4)		Total
Terry K. Spencer	2015	$	490,000	$	1,592,694	$	178,500	$	120,671	$	38,193	$	2,420,058
President and Chief Executive Officer	2014	$	670,058	$	2,157,814	$	447,981	$	539,424	$	54,709	$	3,869,986
	2013	$	390,180	$	887,578	$	152,821	$	29,645	$	44,176	$	1,504,400
Derek S. Reiners	2015	$	300,000	$	682,525	$	78,400	$	—	$	36,828	$	1,097,753
Senior Vice President, Chief Financial Officer and Treasurer	2014	$	358,960	$	808,883	$	143,584	$	—	$	45,233	$	1,356,660
	2013	$	211,348	$	352,067	$	55,276	$	—	$	28,861	$	647,552
Robert F. Martinovich	2015	$	493,738	$	842,470	$	132,322	$	—	$	61,331	$	1,529,861
Executive Vice President and Chief Administrative Officer	2014	$	478,613	$	808,883	$	215,376	$	—	$	64,186	$	1,567,058
	2013	$	325,150	$	528,871	$	104,048	$	—	$	52,273	$	1,010,342
Sheridan C. Swords	2015	$	450,000	$	569,173	$	112,000	$	(7,770)	$	49,722	$	1,173,125
Senior Vice President, Natural Gas Liquids	2014	$	450,000	$	563,940	$	205,000	$	90,432	$	49,654	$	1,359,026
	2013	$	435,000	$	541,391	$	140,000	$	(13,740)	$	63,282	$	1,165,933
Wesley J. Christensen	2015	$	394,990	$	842,470	$	115,535	$	44,426	$	44,657	$	1,442,078
Senior Vice President, Operations	2014	$	400,000	$	845,029	$	195,000	$	138,304	$	40,654	$	1,618,987
	2013	$	340,000	$	541,391	$	100,000	$	33,100	$	43,482	$	1,057,973

(1) The amounts included in the table relate to restricted stock incentive units and performance units granted under the ONEOK Long-Term Incentive Plan ("LTI Plan") and the ONEOK Equity Compensation Plan ("ECP"), respectively, and reflect the aggregate grant date fair value allocated to us in 2015, 2014 and 2013 calculated pursuant to Financial Accounting Standards Board's Accounting Standards Codification 718, Compensation Stock Computation ("ASC Topic 718"). Material assumptions used in the calculation of the value of these equity grants are included in Note M to the ONEOK audited financial statements for the year ended December 31, 2015, included in the ONEOK 2015 Annual Report on Form 10-K filed with the SEC on February 23, 2016.

The aggregate grant date fair value of restricted stock units for purposes of ASC Topic 718 was determined based on the closing price of ONEOK common stock on the grant date, adjusted for the current dividend yield. With respect to the performance units, the aggregate grant date fair value for purposes of ASC Topic 718 was determined using the probable outcome of the performance conditions as of the grant date based on a valuation model that considers the market condition (total shareholder return) and using assumptions developed from historical information of ONEOK and a peer group of companies. The value included for the performance units is based on 100 percent of the performance units vesting at the end of the three-year performance period. Using the maximum number of shares issuable upon vesting of the performance units (200 percent of the units granted), the aggregate grant date fair value of the performance units allocable to us would be as follows:

Name		2015		2014		2013
Terry K. Spencer	$	2,625,071	$	3,549,678	$	1,447,155
Derek S. Reiners	$	1,125,878	$	1,329,442	$	574,781
Robert F. Martinovich	$	1,389,721	$	1,329,442	$	862,171
Sheridan C. Swords	$	938,232	$	927,075	$	883,870
Wesley J. Christensen	$	1,389,721	$	1,388,850	$	883,870

(2) Reflects the amounts allocated to us under the ONEOK annual short-term incentive plan for each named executive officer. The plan provides that ONEOK officers may receive annual cash incentive awards based on the performance of ONEOK and each officer's individual performance. The corporate and business-unit criteria and individual performance criteria are established annually by the Executive Compensation Committee of the ONEOK Board of Directors. This committee also establishes annual target awards for each ONEOK officer. For a discussion of the performance criteria established by the ONEOK Executive Compensation Committee for 2015 awards under the ONEOK annual short-term incentive plan, see "2015 Annual Short-Term Incentive Awards" in the Executive Compensation Discussion and Analysis section of the ONEOK 2016 Proxy Statement.

(3) The amounts reflected represent the aggregate change during 2015 in the actuarial present value of the named executive officers' accumulated benefits under the ONEOK, Inc. Retirement Plan and the ONEOK, Inc. Supplemental Executive Retirement Plan. A description of the ONEOK, Inc. Retirement Plan and the ONEOK, Inc. Supplemental Executive Retirement Plan is set forth in the Executive Compensation and Discussion and Analysis section of the ONEOK 2016 Proxy Statement. The change in the present value of the accrued pension benefit is impacted by variables such as additional years of service, age and the discount rate used to calculate the present value of the change. For 2015, the change in pension value reflects an increase due to additional service and pay for the year, partially offset by a decrease in present value due to the higher discount rate (5.25 percent for fiscal 2015, up from 4.50 percent in 2014). The ONEOK, Inc. Retirement Plan was closed to new participants as of December 31, 2004, and the only named executive officers who participate in the plan are Messrs. Spencer, Christensen and Swords.

(4) Reflects the portion allocated to us of (i) the amounts paid as ONEOK's dollar-for-dollar match of contributions made by the named executive officer under both the ONEOK, Inc. Nonqualified Deferred Compensation Plan and the ONEOK, Inc. 401(k) Plan, as well as quarterly and annual contributions to the ONEOK, Inc. Profit Sharing Plan and corresponding excess contributions to the ONEOK, Inc. Nonqualified Deferred Compensation Plan, (ii) amounts paid for length of service awards, and (iii) the value of shares received under the ONEOK Employee Stock Award Program as of the date of issuance, as follows:

Name	Year	Match Under Nonqualified Deferred Compensation Plan (a)	Match Under 401(k) Plan (b)	Company Contribution to Profit Sharing Plan (c)	Service Award	Stock Award
Terry K. Spencer	2015	$ 27,063	$ 11,130	$ —	$ —	$ —
	2014	$ 38,768	$ 14,933	$ —	$ —	$ 1,009
	2013	$ 33,750	$ 9,950	$ —	$ —	$ 476
Derek S. Reiners	2015	$ 17,748	$ 12,720	$ 6,360	$ —	$ —
	2014	$ 19,145	$ 14,933	$ 9,956	$ 192	$ 1,009
	2013	$ 13,461	$ 9,950	$ 4,975	$ —	$ 476
Robert F. Martinovich	2015	$ 37,780	$ 15,701	$ 7,850	$ —	$ —
	2014	$ 38,289	$ 14,933	$ 9,956	$ —	$ 1,009
	2013	$ 36,872	$ 9,950	$ 4,975	$ —	$ 476
Sheridan C. Swords	2015	$ 33,822	$ 15,900	$ —	$ —	$ —
	2014	$ 33,000	$ 15,600	$ —	$ —	$ 1,054
	2013	$ 47,250	$ 15,300	$ —	$ —	$ 732
Wesley J. Christensen	2015	$ 27,574	$ 15,701	$ —	$ 1,382	$ —
	2014	$ 24,000	$ 15,600	$ —	$ —	$ 1,054
	2013	$ 27,450	$ 15,300	$ —	$ —	$ 732

(a) Additional information on the ONEOK, Inc. Nonqualified Deferred Compensation Plan, is set forth in "Long-Term Compensation Plans - Nonqualified Deferred Compensation Plan" in the Executive Compensation Discussion and Analysis section of the ONEOK 2016 Proxy Statement.

(b) The ONEOK, Inc. 401(k) Plan is a tax-qualified plan that covers substantially all ONEOK employees. Employee contributions are discretionary. Subject to certain limits, ONEOK matches 100 percent of employee contributions to the plan up to a maximum of 6 percent.

(c) The ONEOK, Inc. Profit Sharing Plan covers all eligible employees hired after December 31, 2004, and employees who accepted a one-time opportunity to opt out of the ONEOK, Inc. Retirement Plan. ONEOK plans to make a contribution to the ONEOK, Inc. Profit Sharing Plan each quarter equal to 1 percent of each participant's eligible compensation during the quarter. Additional discretionary contributions may be made by ONEOK at the end of each year. Employee contributions are not allowed under the plan.

Does not reflect charitable contributions made by ONEOK or the ONEOK Foundation, Inc. on behalf of the named executive officer consisting of (i) matching contributions up to $5,000 per year made to nonprofit organizations of the officer's choice under our matching grant program, and (ii) matching contributions to the United Way pursuant to our annual United Way Contribution Program. The amounts contributed in 2015, 2014 and 2013 will be included in the Summary Compensation Table in the ONEOK 2016 Proxy Statement when filed with the SEC as follows: Mr. Spencer, $23,150, $20,000 and $18,150; Mr. Reiners, $5,250, $3,750 and $4,250; Mr. Martinovich, $12,600, $15,000 and $13,050; Mr. Swords, $4,500, $4,500 and $4,350; and Mr. Christensen, $1,800. $1,800 and $1,850, respectively.

The named executive officers did not receive any other perquisites or other personal benefits with an aggregate value of $10,000 or more during 2015, 2014 or 2013.

Potential Postemployment Payments and Payments upon a Change in Control

The following is a description of the postemployment compensation and benefits that ONEOK provides our named executive officers. The objectives of the postemployment compensation and benefits that ONEOK provides are to:

- assist in recruiting and retaining talented executives in a competitive market;
- provide security for any compensation or benefits that have been earned;
- permit executives to focus on our business;
- eliminate any potential personal bias of an executive against a transaction that is in the best interest of ONEOK shareholders and our unitholders;
- avoid the costs associated with separately negotiating executive severance benefits; and
- provide ONEOK and us with the flexibility needed to react to a continually changing business environment.

ONEOK has not entered into individual employment agreements with our named executive officers. Instead, the rights of ONEOK executives with respect to specific events, other than a change in control, including death, disability, severance or retirement are covered by ONEOK's compensation and benefit plans. Under this approach, post-employment compensation and benefits are established separately from the other compensation elements of ONEOK executives.

The use of a "plan approach" instead of individual employment agreements serves several objectives. First, the plan approach provides ONEOK with more flexibility to change the terms of severance benefits from time to time, if necessary. Second, the plan approach is more transparent, both internally and externally. Internal transparency eliminates the need to negotiate separation benefits on a case-by-case basis and assures an executive that his or her severance benefits are comparable with those of his or her peers. Finally, the plan approach is easier for ONEOK to administer, as it requires less time and expense.

Payments Made Upon Any Termination - Regardless of the manner in which a named executive officer's employment terminates, he or she is entitled to receive amounts earned during their term of employment. Such amounts include:

- accrued but unpaid salary;
- amounts contributed under the ONEOK, Inc. 401(k) Plan, the ONEOK, Inc. Profit Sharing Plan and the ONEOK, Inc. Employee Nonqualified Deferred Compensation Plan;
- amounts accrued and vested through the ONEOK, Inc. Retirement Plan and the ONEOK, Inc. Supplemental Executive Retirement Plan; and
- unused prorated vacation.

Payments Made Upon Retirement - In the event of the retirement of a named executive officer, in addition to the items identified above, such named executive officer will be entitled to:

- receive a prorated portion of each outstanding performance unit granted under the ONEOK Equity Compensation Plan upon the completion of the performance period;
- receive a prorated portion of each outstanding restricted stock incentive unit granted under either the ONEOK Long-Term Incentive Plan or the ONEOK Equity Compensation Plan; and
- receive ONEOK health and life benefits for the retiree and qualifying dependents.

Payments Made Upon Death or Disability - In the event of the death or disability of a named executive officer, in addition to the benefits listed under the headings "Payments Made Upon Any Termination" and "Payments Made Upon Retirement" above, the named executive officer will receive applicable benefits under ONEOK's disability plan or payments under ONEOK's life insurance plan.

Payments Made Upon a Change in Control - ONEOK has adopted an Officer Change-in-Control Severance Plan (the Change-in-Control Plan), which covers all ONEOK executive officers, including the named executive officers. Subject to certain exceptions, the Change-in-Control Plan will provide ONEOK officers with severance benefits if they are terminated by ONEOK without cause (as defined in the Change-in-Control Plan) or if they resign for good reason (as defined in the Change-in-Control Plan), in each case within two years following a change in control of ONEOK or us. All change-in-control benefits are "double trigger," meaning that payments and benefits under the plan are payable only if the officer's employment is terminated by us without "cause" or by the officer for a "good reason" at any time during the two years following a change in control. Severance payments under the plan consist of a cash payment that may be up to three times the participant's annual salary and target short-term incentive bonus, plus reimbursement of COBRA healthcare premiums for 18 months. At the time the ONEOK Board of Directors approved the Change-in-Control Plan, the Board, upon the recommendation of the ONEOK Executive Compensation Committee, established a severance multiplier of two times their annual salary and target short-term incentive bonus for certain participants in the Change-in-Control Plan, including the named executive officers. The Change-in-

Control Plan does not provide for the credit of additional years of service to any participant to determine the pension amounts payable in the event of a change in control and does not provide an excise tax gross-up for any participant. Rather, severance payments and benefits under the Change-in-Control Plan will be reduced if, as a result of such reduction, the officer would receive a greater total payment after taking taxes, including excise taxes, into account.

For the purposes of the Change-in-Control Plan, a "change in control" generally means any of the following events:

- an acquisition of ONEOK voting securities by any person that results in the person having beneficial ownership of 20 percent or more of the combined voting power of ONEOK's outstanding voting securities, other than an acquisition directly from ONEOK;
- the current members of the ONEOK Board of Directors, and any new director approved by a vote of at least two-thirds of the ONEOK Board, cease for any reason to constitute at least a majority of the ONEOK Board, other than in connection with an actual or threatened proxy contest (collectively, the "Incumbent Board");
- a merger, consolidation or reorganization with ONEOK or in which ONEOK issues securities, unless (a) ONEOK shareholders immediately before the transaction, as a result of the transaction, own, directly or indirectly, at least 50 percent of the combined voting power of the voting securities of the company resulting from the transaction, (b) the members of the Incumbent Board after the execution of the transaction agreement constitute at least a majority of the members of the Board of the company resulting from the transaction, or (c) no person other than persons who, immediately before the transaction owned 20 percent or more of our outstanding voting securities, has beneficial ownership of 20 percent or more of the outstanding voting securities of the company resulting from the transaction;
- ONEOK's complete liquidation or dissolution or the sale or other disposition of all or substantially all of ONEOK's assets; or
- ONEOK ceases to own, directly or indirectly, a majority of each class of the outstanding equity interests of ONEOK Partners GP, our sole general partner, ONEOK ceases to hold the power to designate a majority of the Board of Directors of the Partnership, or our general partner is removed.

For the purposes of the Change-in-Control Plan, termination for "cause" means a termination of employment of a participant in the Change-in-Control Plan by reason of:

- a participant's indictment for or conviction in a court of law of a felony or any crime or offense involving misuse or misappropriation of money or property;
- a participant's violation of any covenant, agreement or obligation not to disclose confidential information regarding the business of ONEOK (or a division or subsidiary) or a participant's violation of any covenant, agreement or obligation not to compete with ONEOK (or a division or subsidiary);
- any act of dishonesty by a participant which adversely affects the business of ONEOK (or a division or subsidiary) or any willful or intentional act of a participant which adversely affects the business, or reflects unfavorably on the reputation, of ONEOK (or a division or subsidiary);
- a participant's material violation of any written policy of ONEOK (or a division or subsidiary); or
- a participant's failure or refusal to perform the specific directives of the ONEOK Board or its officers, which directives are consistent with the scope and nature of the participant's duties and responsibilities, to be determined in the ONEOK Board's sole discretion.

For the purposes of the Change-in-Control Plan, "good reason" means:

- a participant's demotion or material reduction of the participant's significant authority or responsibility with respect to employment with ONEOK from that in effect on the date the change in control occurred:
- a material reduction in the participant's base salary from that in effect immediately prior to the change in control;
- a material reduction in short-term and/or long-term incentive targets from those applicable to the participant immediately prior to the change in control;
- the relocation to a new principal place of employment of the participant's employment by ONEOK, which is more than 35 miles further from the participant's principal place of residence than the participant's principal place of employment was prior to such change; and
- the failure of a successor company to explicitly assume the Change-in-Control Plan.

Potential Postemployment Payment Tables - The following tables reflect estimates of our allocated portion of the amount of incremental compensation due to each named executive officer by ONEOK in the event of such executive's termination of employment by reason of death, disability or retirement, termination of employment without cause, or termination of employment without cause or with good reason within two years following a change in control. The amounts shown assume that such termination was effective as of December 31, 2015, and are estimates of the allocated amounts that would be paid out to the executives upon such termination, including, with respect to performance units, the performance factor calculated as if the performance period had ended on December 31, 2015. The amounts reflected in the "Qualifying Termination Following a Change in Control" column of the tables that follow are the amounts that would be paid pursuant to the ONEOK, Inc. Change-in-Control Plan and, with respect to the performance units, assume a change in control effective December 31, 2015, and a performance factor based on ONEOK's total shareholder return relative to the designated peer group on that date.

Terry K. Spencer	Termination Upon Death, Disability or Retirement	Termination Without Cause	Qualifying Termination Following a Change in Control
Cash Severance	$ —	$ —	$ 1,960,000
Health and Welfare Benefits	$ 56,538	$ 56,538	$ 78,297
Equity			
Restricted Units	$ 231,436	$ 231,436	$ 395,470
Performance Units	$ —	$ —	$ —
Total	$ 231,436	$ 231,436	$ 395,470
Total	$ 287,974	$ 287,974	$ 2,433,767

Derek S. Reiners	Termination Upon Death, Disability or Retirement	Termination Without Cause	Qualifying Termination Following a Change in Control
Cash Severance	$ —	$ —	$ 990,000
Health and Welfare Benefits	$ 34,615	$ 34,615	$ 57,631
Equity			
Restricted Units	$ 101,768	$ 101,768	$ 172,109
Performance Units	$ —	$ —	$ —
Total	$ 101,768	$ 101,768	$ 172,109
Total	$ 136,383	$ 136,383	$ 1,219,740

Robert F. Martinovich	Termination Upon Death, Disability or Retirement	Termination Without Cause	Qualifying Termination Following a Change in Control
Cash Severance	$ —	$ —	$ 1,678,708
Health and Welfare Benefits	$ 56,970	$ 56,970	$ 77,330
Equity			
Restricted Units	$ 157,889	$ 157,889	$ 246,611
Performance Units	$ —	$ —	$ —
Total	$ 157,889	$ 157,889	$ 246,611
Total	$ 214,859	$ 214,859	$ 2,002,649

Sheridan C. Swords	Termination Upon Death, Disability or Retirement	Termination Without Cause	Qualifying Termination Following a Change in Control
Cash Severance	$ —	$ —	$ 1,485,000
Health and Welfare Benefits	$ 51,923	$ 51,923	$ 80,693
Equity			
Restricted Units	$ 106,183	$ 106,183	$ 166,210
Performance Units	$ —	$ —	$ —
Total	$ 106,183	$ 106,183	$ 166,210
Total	$ 158,106	$ 158,106	$ 1,731,903

Wesley J. Christensen	Termination Upon Death, Disability or Retirement	Termination Without Cause	Qualifying Termination Following a Change in Control
Cash Severance	$ —	$ —	$ 1,342,966
Health and Welfare Benefits	$ 45,576	$ 45,576	$ 65,936
Equity			
Restricted Units	$ 125,617	$ 125,617	$ 212,441
Performance Units	$ —	$ —	$ —
Total	$ 125,617	$ 125,617	$ 212,441
Total	$ 171,193	$ 171,193	$ 1,621,343

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Holdings of Major Unitholders

The following table sets forth the beneficial owners of 5 percent or more of our common units and Class B units known to us at December 31, 2015. Other than as set forth below, no person is known to us to beneficially own more than 5 percent of our common units or Class B units.

Name and Address of Beneficial Owner	Common Units	Percent of Common Units	Class B Units	Percent of Class B Units	Percent of All Units
ONEOK, Inc. and affiliates	41,344,581	19.4%	72,988,252	100%	39.2% (1)
100 West Fifth Street					
Tulsa, OK 74103-4298					
Alerian MLP ETF	12,205,641	5.7%	—	—	4.2% (2)
1290 Broadway					
Suite 1100					
Denver, CO 80203					
ALPS Advisors, Inc.	12,259,665	5.8%	—	—	4.2% (3)
1219 Broadway					
Suite 1100					
Denver, CO 80203					
Kayne Anderson Capital Advisors, L.P. and Richard Kane	13,187,079	6.2%	—	—	4.5% (4)
1800 Avenue of the Stars					
Third Floor					
Los Angeles, CA 90067					
Tortoise Capital Advisors, L.L.C.	14,124,537	6.6%	—	—	4.8% (5)
11550 Ash Street					
Suite 300					
Leawood, KS 66211					

(1) Does not reflect the general partner's 2 percent interest, which is wholly owned by ONEOK.

(2) Based upon a Schedule 13G filed with the SEC on February 3, 2016, in which Alerian MLP ETF (Alerian) reported that, as of December 31, 2015, Alerian beneficially owned, in the aggregate, 12,205,641 of our common units with respect to which Alerian had sole voting power with respect to zero common units, shared voting power with respect to 12,205,641 common units, sole dispositive power with respect to zero common units, and shared dispositive power with respect to 12,205,641 common units. Alerian reported that it is an investment company registered under the Investment Company of 1940 to which ALPS Advisors, Inc. provides investment advice (see Note (3) below).

(3) Based upon a Schedule 13G filed with the SEC on February 3, 2016 in which ALPS Advisors, Inc. (ALPS) reported that, as of December 31, 2015, ALPS beneficially owned, in the aggregate, 12,259,665 of our common units with respect to which it had sole voting power with respect to zero common units, shared voting power with respect to 12,259,665 common units, sole dispositive power with respect to zero common units, and shared dispositive power with respect to 12,259,665 common units. ALPS reported that it is an investment advisor registered under the Investment Advisors Act of 1940 and provides investment advice to investment companies registered under the Investment Company Act of 1940 and that Alerian is one of the investment companies to which ALPS provides investment advice (see Note (2) above). ALPS also reported that, in its role as investment advisor, it has voting and/or investment power over our securities owned by Alerian, it may be deemed to be the beneficial owner of such securities, all such securities are owned by Alerian and ALPS disclaims beneficial ownership of such securities.

(4) Based upon a Schedule 13G filed with the SEC on January 29, 2016, in which Kayne Anderson Capital Advisors, L.P. (Kayne Anderson) and Richard A. Kayne reported that, as of December 31, 2015, Kayne Anderson and Mr. Kayne owned, in the aggregate, 13,187,079 shares of our common units with respect to which Kayne Anderson had sole power to vote zero shares, shared power to vote 13,187,079 shares, sole dispositive power with respect to zero shares, and shared dispositive power with respect to 13,187,079 shares. Kayne Anderson reported that: the reported units are owned by investment accounts (investment limited partnerships, a registered investment company and institutional accounts) managed, with discretion to purchase or sell securities, by Kayne Anderson, as a registered investment advisor; Kayne Anderson is the general partner (or general partner of the general partner) of the limited partnerships and investment advisor to the other accounts; and Mr. Kayne is the controlling shareholder of the corporate owner of Kayne Anderson Investment Management, Inc., the general partner of Kayne Anderson and that Mr. Kayne is also a limited partner of each of the limited partnerships and a shareholder of the registered investment company. Kayne Anderson reported that it disclaims beneficial ownership of the units reported, except those units attributable to it by virtue of its general partner interests in the limited partnerships, and that Mr. Kayne disclaims beneficial ownership of the units reported, except those units held by him or attributable to him by virtue of his limited

partnership interests in the limited partnerships, his indirect interest in the interest of Kayne Anderson in the limited partnerships, and his ownership of common stock of the registered investment company.

On December 29, 2015, Kevin S. McCarthy was elected to the ONEOK Board of Directors. Mr. McCarthy is a managing partner for KA Fund Advisors, LLC (KAFA) and is co-managing partner of the energy marketable securities activities at Kayne Anderson. He serves as chairman, president and chief executive officer of the Kayne Anderson MLP Investment Company (KYN), Kayne Anderson Energy Total Return Fund (KYE), Kayne Anderson Midstream/Energy Fund (KMF) and Kayne Anderson Energy Development Company (KED), which are each New York Stock Exchange listed closed-end investment companies, (together, the Public Funds). In connection with his appointment to the ONEOK Board, KAFA has implemented controls designed to ensure that Mr. McCarthy will not possess investment or voting power for common units held by the Public Funds and the other accounts referenced below. Other private funds and accounts (the Private Funds) managed by Kayne Anderson also own ONEOK Partners common units, but Mr. McCarthy does not have any day-to-day responsibilities with respect to the investment activities of such Private Funds. Mr. McCarthy disclaims beneficial ownership of the ONEOK Partners common units held by the Public Funds and Private Funds, except to the extent of his primary interest therein.

(5) Based on a Schedule 13g filed with the SEC on February 9, 2016, in which Tortoise Capital Advisors, L.L.C. (TCA) reported that as of December 31, 2015, TCA owned, in the aggregate, 14,124,537 of our common units with respect to which TCA had sole voting power over 159,082 common units, shared voting power over 13,114,668 common units, sole dispositive power over 159,082 common units and shared dispositive power over 13,965,455 common units.

TCA reported that it acts as an investment adviser to certain investment companies registered under the Investment Company Act of 1940 (the Act), and that by virtue of investment advisory agreements with these investment companies, TCA has all investment and voting power over securities owned of record by these investment companies. However, despite their delegation of investment and voting power to TCA, these investment companies may be deemed to be the beneficial owners under Rule 13d-3 of the Act, of the securities they own of record because they have the right to acquire investment and voting power through termination of their investment advisory agreement with TCA. Thus, TCA reported that it shares voting power and dispositive power over the securities owned of record by these investment companies. TCA also reported that it acts as an investment advisor to certain managed accounts and that under contractual agreements with these managed account clients, TCA, with respect to the securities held in these client accounts, has investment and voting power with respect to certain of these client accounts, and has investment power but no voting power with respect to certain other of these client accounts. TCA reported that it shares voting and/or investment power over the securities held by these client managed accounts despite a delegation of voting and/or investment power to TCA because the clients have the right to acquire investment and voting power through termination of their agreements with TCA. TCA reported that it may be deemed the beneficial owner of the securities covered by this statement under Rule 13d-3 of the Act that are held by its clients.

Holdings of Officers and Directors

The following table sets forth the beneficial ownership of our common units and the common stock of ONEOK, the parent company of our general partner, as of February 1, 2016, by each named executive officer, each member of our Board of Directors of our general partner, and all executive officers and members of our Board of Directors as a group.

Name and Address of Beneficial Owner (1)	Common Units	Percent of Common Units	Class B Units	Percent of Class B Units	Percent of All Units	ONEOK Shares (2)	Percent of ONEOK Shares
John W. Gibson	100,000	*	—	—	*	1,111,837	*
Terry K. Spencer	27,400	*	—	—	*	290,648	*
Derek S. Reiners	—	—	—	—	—	41,685	*
Robert F. Martinovich	288	*	—	—	*	189,896	*
Sheridan C. Swords	—	—	—	—	—	130,216	*
Stephen W. Lake	—	—	—	—	—	26,554	*
Wesley J. Christensen	—	—	—	—	—	29,649	*
Julie H. Edwards	—	—	—	—	—	39,599	*
Steven J. Malcolm	—	—	—	—	—	13,213	*
Michael G. Hutchinson	2,000	*	—	—	*	—	—
Jim W. Mogg	2,000	*	—	—	*	—	—
Gary N. Petersen	20,284	*	—	—	*	—	—
Craig F. Strehl	9,400	*	—	—	*	—	—
All directors and executive officers as a group	163,772	*	—	—	*	1,919,010	*

* Less than 1 percent

(1) The business address for each of the beneficial owners is c/o ONEOK Partners, L.P., 100 West Fifth Street, Tulsa, Oklahoma 74103-4298.

(2) Includes shares of ONEOK common stock held by members of the family of the director or executive officer for which the director or executive officer has sole or shared voting or investment power, shares of common stock held in ONEOK's Direct Stock Purchase and Dividend Reinvestment Plan, ONEOK, Inc. 401(k) Plan and ONEOK, Inc. Profit Sharing Plan, and shares issuable pursuant to ONEOK 2013 restricted stock units and performance units upon vesting on February 20, 2016 (including accrued dividend equivalents and assuming the performance units vest at the 100 percent level).

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Related-Person Transactions

Our Board of Directors recognizes that transactions between us and related persons (ONEOK and its subsidiaries and affiliates and their and our executive officers, directors and their immediate family members) can present potential or actual conflicts of interest and create the appearance our decisions are based on considerations other than the best interest of the Partnership and our unitholders. Accordingly, it is our preference to avoid related-person transactions. Nevertheless, we recognize that there are situations where related-person transactions may be in, or may not be inconsistent with, our and our unitholders' best interests including, but not limited to, situations where we acquire products or services from related persons on an arm's length basis on terms comparable with those provided to unrelated third parties. In the event we enter into a transaction in which ONEOK or its subsidiaries or affiliates or their or our executive officers (other than an employment relationship), directors or a member of their immediate family have a direct or indirect material interest, the transaction is presented to our Audit Committee and, if warranted, our Conflicts Committee for review to determine if the transaction creates a conflict of interest and is otherwise fair and reasonable to the Partnership. In determining whether a particular transaction creates a conflict of interest and, if so, is fair and reasonable to the Partnership, our Audit Committee and, if warranted, our Conflicts Committee consider the specific facts and circumstances applicable to each such transaction, including: the parties to the transaction; their relationship to the Partnership and nature of their interest in the transaction; the nature of the transaction; the aggregate value of the transaction; the length of the transaction; whether the transaction occurs in the normal course of our business; the benefits to the Partnership provided by the transaction; if applicable, the availability of other sources of comparable products or services; and, if applicable, whether the terms of the transaction, including price or other consideration, are the same or substantially the same as those available to the Partnership if the transaction were entered into with an unrelated party.

We require each executive officer and director of our general partner to annually provide us written disclosure of any transaction between the officer or director and us. The Board of Directors of our general partner reviews this disclosure in connection with its annual review of the independence of our Board of Directors and our Audit and Conflicts Committees. These procedures are not in writing but are documented through the meeting agendas of the Board of Directors of our general partner.

Relationship with ONEOK

ONEOK owns our sole general partner, ONEOK Partners GP, and appoints members of our Board of Directors and our Audit and Conflicts Committees. ONEOK and its subsidiaries continue to own the entire general partner interest in us and limited partners units, which together at December 31, 2015, represented a 41.2 percent interest in us.

Other relationships with ONEOK include the following:

Cash Distributions - ONEOK and its affiliates own all of our 72,988,252 Class B units, 41,344,581 of our common units and our entire 2 percent general partner interest, which together constituted a 41.2 percent ownership interest in us at December 31, 2015. In 2015, we paid total cash distributions to ONEOK of $706.3 million, which included $371.5 million related to its incentive distribution rights. Additional information about our cash distribution policy is included in Item 5, Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

Services Agreement - In April 2006, we entered into a Services Agreement with ONEOK and ONEOK Partners GP. Under the Services Agreement, our operations and the operations of ONEOK and its affiliates can combine or share certain common services in order to operate more efficiently and cost effectively. Under the Services Agreement, ONEOK provides to us similar services that it provides to its affiliates, including those services required to be provided by the general partner pursuant to our Partnership Agreement.

ONEOK and its affiliates provide a variety of services to us under the Services Agreement, including cash management and financial services, employee benefits provided through ONEOK's benefit plans, legal, administrative and insurance services, and office space in ONEOK's headquarters building and other field locations. Where costs are specifically incurred on behalf of one of our affiliates, the costs are billed directly to us by ONEOK. In other situations, the costs may be allocated to us through a variety of methods, depending upon the nature of the expense and activities. For example, a service that applies equally to all employees is allocated based upon the number of employees; however, an expense benefiting the consolidated company, but which has no direct basis for allocation, is allocated by the modified Distrigas method, a widely recognized method of allocating cost which uses a combination of ratios that include gross plant and investment, operating income and payroll expense. All costs directly charged or allocated to us are included in our Consolidated Statements of Income. In 2015, the aggregate amount charged by ONEOK and their affiliates to us for their services was approximately $368.3 million.

Operating and Administrative Services Agreements - ONEOK Partners GP provides certain administrative, operating and management services to us and Midwestern Gas Transmission, Viking Gas Transmission and Guardian Pipeline through operating agreements. We, along with Midwestern Gas Transmission, Viking Gas Transmission and Guardian Pipeline, are charged for the salaries, benefits and expenses of ONEOK Partners GP incurred in connection with these operating agreements.

Affiliate Transactions - We own 50 percent of Northern Border Pipeline but do not serve as its operator. We account for our investment in Northern Border Pipeline using the equity method. In 2015, Northern Border Pipeline's revenue for capacity contracted on a firm basis included $22.2 million from ONEOK and its subsidiaries.

We own 50 percent of Overland Pass Pipeline Company but do not serve as its operator. We account for our investment in Overland Pass Pipeline Company using the equity method. In 2015, Overland Pass Pipeline Company's revenue for capacity contracted on a firm basis included $82.2 million from us.

Conflicts of Interest

We are managed under the direction of the Board of Directors of our general partner, which establishes our business policies. ONEOK, which is the parent company of our general partner, appoints the members of our Board of Directors and may change the composition or size of our Board at its discretion.

ONEOK and its affiliates currently engage or may engage in the businesses in which we engage or in which we may engage in the future and neither ONEOK nor any of its affiliates has any obligation to present business opportunities to us.

ONEOK and its other affiliates may from time to time engage in transactions with us. As a result, conflicts of interest may arise between ONEOK and its other affiliates, and us. If such conflicts arise, then, in accordance with the provisions of our Partnership Agreement, the members of our Board of Directors may themselves resolve such conflicts or may seek to have such conflicts of interest approved by either our Conflicts Committee (comprised of independent members of our Board of Directors who are not also members of ONEOK's Board of Directors) and/or by a vote of unitholders.

Unless otherwise provided for in a partnership agreement, the laws of Delaware generally require a general partner of a partnership to adhere to fiduciary duty standards under which it owes its partners the highest duties of good faith, fairness and loyalty. Similar rules apply to persons serving on our Board of Directors. Because of the competing interests identified above, our Partnership Agreement contains provisions that modify or in some cases eliminate certain of these fiduciary duties. For example:

- Our Partnership Agreement states that our general partner, its affiliates and their officers and directors will not be liable for damages to us, our limited partners or their assignees for errors of judgment or for any acts or omissions if the general partner and such other persons acted in good faith;
- Our Partnership Agreement allows our general partner and our Board of Directors to take into account the interests of other parties in addition to our interests in resolving conflicts of interest;
- Our Partnership Agreement provides that our general partner will not be in breach of its obligations under our Partnership Agreement or its duties to us or our unitholders if the resolution of a conflict is "fair and reasonable" to us. The latitude given in our Partnership Agreement in connection with resolving conflicts of interest may significantly limit the ability of a unitholder to challenge what might otherwise be a breach of fiduciary duty;
- Our Partnership Agreement provides that a purchaser of common units is deemed to have consented to certain conflicts of interest and actions of our general partner and its affiliates that might otherwise be prohibited and to have agreed that such conflicts of interest and actions do not constitute a breach by the general partner of any duty stated or implied by law or equity;
- The Conflicts Committee of our general partner will, at the request of the general partner or a member of our Board of Directors, review conflicts of interest that may arise between a general partner and its affiliates (or the member of our Board of Directors designated by it), and the unitholders or us. Any resolution of a conflict approved by the Conflicts Committee is conclusively deemed "fair and reasonable" to us;
- The Partnership agreement of Northern Border Pipeline relieves us and TC PipeLines, our affiliates and transferees from any duty to offer business opportunities to Northern Border Pipeline, subject to specified exceptions; and
- The limited liability company agreement of Overland Pass Pipeline Company provides that members and their respective affiliates may engage, directly or indirectly, without the consent of the other members or Overland Pass Pipeline Company, in other business opportunities, transactions, ventures or other arrangements of any nature which

may be competitive with or the same as or similar to the business of Overland Pass Pipeline Company, regardless of the geographic location of such business, and without any duty or obligation to account to the other members or Overland Pass Pipeline Company.

We are required to indemnify the general partner, the members of its Board of Directors, and its affiliates and their respective officers, directors, employees, agents and trustees to the fullest extent permitted by law against liabilities, costs and expenses incurred by any such person who acted in "good faith" and in a manner reasonably believed to be in, or (in the case of a person other than our general partner) not opposed to, our best interests and with respect to any criminal proceedings, had no reasonable cause to believe the conduct was unlawful. Insofar as indemnification for liabilities arising under the Securities Act may be permitted to directors, officers or persons controlling us pursuant to the foregoing provisions or otherwise, we have been advised that in the opinion of the SEC, such indemnification is against public policy as expressed in the Securities Act and is, therefore, unenforceable.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Audit and Nonaudit Fees

Audit services provided by PricewaterhouseCoopers LLP during the 2015 and 2014 fiscal years included integrated audits of our consolidated financial statements and internal control over financial reporting, audits of the financial statements of certain of our affiliates, review of our quarterly financial statements, consents, and review of documents filed with the SEC.

The following table presents fees billed for services rendered by PricewaterhouseCoopers LLP for the years ended December 31, 2015 and 2014:

	2015	2014
	(*Thousands of dollars*)	
Audit fees	$ 1,796	$ 1,596
Audit-related fees	—	—
Tax fees (1)	912	745
All other fees	—	—
Total	$ 2,708	$ 2,341

(1) Tax fees consisted of fees for tax compliance, tax planning or tax services, including preparation of our annual K-1 statements.

Audit Committee Policy on Services Provided by Independent Auditor

Consistent with SEC and NYSE policies regarding auditor independence, the Audit Committee has responsibility for appointing, setting compensation and overseeing the work of the independent auditor. In recognition of this responsibility, the Audit Committee has established a policy with respect to the preapproval of audit and permissible nonaudit services provided by the independent auditor.

Prior to engagement of PricewaterhouseCoopers LLP as our independent auditor for the 2015 audit, a plan was submitted to and approved by the Audit Committee setting forth the services expected to be rendered during 2015 for each of the following four categories:

(1) audit services comprised of work performed in the audit of our financial statements and to attest and report on management's assessment of our internal controls over financial reporting, as well as work that only the independent auditor can reasonably be expected to provide, including quarterly review of our unaudited financial statements, comfort letters, statutory audits, attestation services, consents and assistance with the review of documents filed with the SEC;

(2) audit-related services comprised of assurance and related services that are traditionally performed by the independent auditor, including due diligence related to mergers and acquisitions and consultation regarding financial accounting and/or reporting standards;

(3) tax services comprised of tax compliance, tax planning and tax advice; and

(4) all other permissible nonaudit services, if any, that the Audit Committee believes are routine and recurring services that would not impair the independence of the auditor.

Audit fees are budgeted, and the Audit Committee requires the independent auditor and management to report actual fees compared with budgeted fees periodically during the year by category of service.

The Audit Committee has adopted a policy that provides that fees for services that are not included in the independent auditor's annual services plan and that are not determinable on an annual basis are preapproved if the fees for such services will not exceed $75,000. In addition, the policy provides that the Audit Committee may delegate preapproval authority to one or more of its members. The member to whom such authority is delegated must report, for informational purposes only, any preapproval decisions to the Audit Committee at its next scheduled meeting.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(2) Financial Statements Schedules

All schedules have been omitted because of the absence of conditions under which they are required.

(3) Exhibits

3.0	Amendment No. 2 to Third Amended and Restated Agreement of Limited Partnership of ONEOK Partners, L.P. dated July 12, 2011 (incorporated by reference to Exhibit 3.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on July 13, 2011 (File No. 1-12202)).
3.1	Northern Border Partners, L.P. Certificate of Limited Partnership dated July 12, 1993, Certificate of Amendment dated February 16, 2001, and Certificate of Amendment dated May 20, 2003 (incorporated by reference to Exhibit 3.1 to Northern Border Partners, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2004, filed on March 14, 2005 (File No. 1-12202)).
3.2	Certificate of Amendment to Certificate of Limited Partnership of Northern Border Partners, L.P. dated May 17, 2006 (incorporated by reference to Exhibit 3.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on May 23, 2006 (File No. 1-12202)).
3.3	Third Amended and Restated Agreement of Limited Partnership of ONEOK Partners, L.P. dated as of September 15, 2006 (incorporated by reference to Exhibit 3.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on September 19, 2006 (File No. 1-12202)).
3.4	Certificate of Formation of ONEOK Partners GP, L.L.C., as amended, dated as of May 15, 2006 (incorporated by reference to Exhibit 3.5 to ONEOK Partners, L.P.'s Quarterly Report on Form 10-Q for the period ended June 30, 2006, filed on August 4, 2006 (File No. 1-12202)).
3.5	Amendment No. 3 to Third Amended and Restated Agreement of Limited Partnership of ONEOK Partners, L.P. (incorporated by reference to Exhibit 3.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on February 17, 2012 (File No. 1-12202)).

3.6	Certificate of Limited Partnership of Northern Border Intermediate Limited Partnership dated July 12, 1993, Certificate of Amendment dated February 16, 2001, and Certificate of Amendment dated May 20, 2003 (incorporated by reference to Exhibit 3.3 to Northern Border Partners, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2004, filed on March 14, 2005 (File No 1-12202)).
3.7	Certificate of Amendment to Certificate of Limited Partnership of Northern Border Intermediate Limited Partnership dated May 17, 2006 (incorporated by reference to Exhibit 3.3 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on May 23, 2006 (File No. 1-12202)).
3.8	Certificate of Amendment to Certificate of Limited Partnership of ONEOK Partners Intermediate Limited Partnership dated September 15, 2006 (incorporated by reference to Exhibit 3.2 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on September 19, 2006 (File No. 1-12202)).
3.9	Second Amended and Restated Agreement of Limited Partnership of ONEOK Partners Intermediate Limited Partnership dated as of May 17, 2006 (incorporated by reference to Exhibit 3.4 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on May 23, 2006 (File No. 1-12202)).
3.10	Amendment No. 1 to Second Amended and Restated Agreement of Limited Partnership of ONEOK Partners Intermediate Limited Partnership dated as of September 15, 2006 (incorporated by reference to Exhibit 3.3 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on September 19, 2006 (File No. 1-12202)).
3.11	Certificate of Formation of ONEOK ILP GP, L.L.C. dated May 12, 2006 (incorporated by reference to Exhibit 4.11 to ONEOK Partners, L.P.'s Registration Statement on Form S-3 filed on September 19, 2006 (File No. 333-137419)).
3.12	Not used.
3.13	Amendment No. 1 to Third Amended and Restated Agreement of Limited Partnership of ONEOK Partners, L.P. dated July 20, 2007 (incorporated by reference to Exhibit 3.1 to ONEOK Partners, L.P.'s Quarterly Report on Form 10-Q for the period ended June 30, 2007, filed on August 3, 2007 (File No. 1-12202)).
4.1	Thirteenth Supplemental Indenture, dated March 20, 2015, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A., as trustee, with respect to the 3.80 percent Senior Notes due 2020 (incorporated by reference to Exhibit 4.2 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on March 20, 2015 (File No. 1-12202)).
4.2	Fourteenth Supplemental Indenture, dated March 20, 2015, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A., as trustee, with respect to the 4.90 percent Senior Notes due 2025 (incorporated by reference to Exhibit 4.3 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on March 20, 2015 (File No. 1-12202)).
4.3	Not used.
4.4	Indenture, dated as of September 25, 2006, between ONEOK Partners, L.P. and Wells Fargo Bank, N.A., as trustee (incorporated by reference to Exhibit 4.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on September 26, 2006 (File No. 1-12202)).
4.5	Not used.
4.6	Second Supplemental Indenture, dated as of September 25, 2006, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A., as trustee, with respect to the 6.15 percent Senior Notes due 2016 (incorporated by reference to Exhibit 4.3 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on September 26, 2006 (File No. 1-12202)).

4.7	Third Supplemental Indenture, dated as of September 25, 2006, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A., as trustee, with respect to the 6.65 percent Senior Notes due 2036 (incorporated by reference to Exhibit 4.4 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on September 26, 2006 (File No. 1-12202)).
4.8	Eighth Supplemental Indenture, dated as of September 13, 2012, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A., as trustee, with respect to the 2.000 percent Senior Notes due 2017 (incorporated by reference from Exhibit 4.2 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on September 13, 2012 (File No. 1-12202)).
4.9	Ninth Supplemental Indenture, dated as of September 13, 2012, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A., as trustee, with respect to the 3.375 percent Senior Notes due 2022 (incorporated by reference from Exhibit 4.3 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on September 13, 2012 (File No. 1-12202)).
4.10	Tenth Supplemental Indenture, dated September 12, 2013, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A., as trustee, with respect to the 3.200 percent Senior Notes due 2018 (incorporated by reference to Exhibit 4.2 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on September 12, 2013 (File No. 1-12202)).
4.11	Form of Class B unit certificate (incorporated by reference to Exhibit 4.1 to Northern Border Partners, L.P.'s Current Report on Form 8-K filed on April 12, 2006 (File No. 1-12202)).
4.12	Eleventh Supplemental Indenture, dated September 12, 2013, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A., as trustee, with respect to the 5.000 percent Senior Notes due 2023 (incorporated by reference to Exhibit 4.3 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on September 12, 2013 (File No. 1-12202)).
4.13	Fourth Supplemental Indenture, dated as of September 28, 2007, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A., as trustee, with respect to the 6.85 percent Senior Notes due 2037 (incorporated by reference to Exhibit 4.2 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on September 28, 2007 (File No. 1-12202)).
4.14	Twelfth Supplemental Indenture, dated September 12, 2013, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A., as trustee, with respect to the 6.200 percent Senior Notes due 2043 (incorporated by reference to Exhibit 4.4 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on September 12, 2013 (File No. 1-12202)).
4.15	Fifth Supplemental Indenture, dated as of March 3, 2009, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A., as trustee, with respect to the 8.625 percent Senior Notes due 2019 (incorporated by reference to Exhibit 4.2 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on March 3, 2009 (File No. 1-12202)).
4.16	Sixth Supplemental Indenture, dated January 26, 2011, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A., as trustee, with respect to the 3.250 percent Senior Notes due 2016 (incorporated by reference to Exhibit 4.2 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on January 26, 2011 (File No. 1-12202)).
4.17	Seventh Supplemental Indenture, dated January 26, 2011, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A., as trustee, with respect to the 6.125 percent Senior Notes due 2041 (incorporated by reference to Exhibit 4.3 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on January 26, 2011 (File No. 1-12202)).

10.1	First Amended and Restated General Partnership Agreement of Northern Border Pipeline Company, dated April 6, 2006, by and between Northern Border Intermediate Limited Partnership and TC PipeLines Intermediate Limited Partnership (incorporated by reference to Exhibit 3.1 to Northern Border Pipeline Company's Current Report on Form 8-K filed on April 12, 2006 (File No. 333-87753)).
10.2	Underwriting Agreement, dated as of May 13, 2014, among ONEOK Partners, L.P., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Barclays Capital Inc., Morgan Stanley & Co. LLC, UBS Securities LLC and Wells Fargo Securities, LLC, as representatives of several underwriters named therein (incorporated by reference to Exhibit 1.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on May 16, 2014 (File No. 1-12202)).
10.3	Services Agreement executed April 6, 2006 but effective as of April 1, 2006, by and among ONEOK, Inc., Northern Plains Natural Gas Company, LLC, NBP Services, LLC, Northern Border Partners, L.P. and Northern Border Intermediate Limited Partnership (incorporated by reference to Exhibit 10.3 to Northern Border Partners, L.P.'s Current Report on Form 8-K filed on April 12, 2006 (File No. 1-12202)).
10.4	Amended and Restated Credit Agreement, effective as of January 31, 2014, among ONEOK Partners, L.P., Citibank, N.A., as administrative agent, swing-line lender, a letter of credit issuer and a lender, and the other lenders and letter of credit issuers parties thereto, attached as an annex to that certain Amendment Agreement, dated as of December 20, 2013 (incorporated by reference to Exhibit 10.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on December 23, 2013 (File No. 1-12202)).
10.5	Guaranty Agreement, dated as of January 31, 2014, by ONEOK Partners Intermediate Limited Partnership in favor of the Citibank, N.A., as administrative agent, under the above-referenced Amended and Restated Credit Agreement (incorporated by reference to Exhibit 10.2 to ONEOK Partners, L.P.'s Quarterly Report on Form 10-Q for the period ended March 31, 2014, filed on May 7, 2014 (File No. 1-12202)).
10.6	Amended and Restated Limited Liability Company Agreement of Overland Pass Pipeline Company LLC entered into between ONEOK Overland Pass Holdings, L.L.C. and Williams Field Services Company, LLC dated May 31, 2006 (incorporated by reference to Exhibit 10.6 to ONEOK Partners, L.P.'s Quarterly Report on Form 10-Q for the period ended June 30, 2006, filed on August 4, 2006 (File No. 1-12202)).
10.7	Amendment No. 1 to Third Amended and Restated Limited Liability Company Agreement of ONEOK Partners GP, L.L.C. effective July 14, 2009 (incorporated by reference to Exhibit 10.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on February 17, 2012 (File No. 1-12202)).
10.8	Third Amended and Restated Limited Liability Company Agreement of ONEOK Partners GP, L.L.C. effective July 14, 2009 (incorporated by reference to Exhibit 99.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on July 17, 2009 (File No. 1-12202)).
10.9	First Amended and Restated Limited Liability Company Agreement of ONEOK ILP GP, L.L.C. effective July 14, 2009 (incorporated by reference to Exhibit 99.2 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on July 17, 2009 (File No. 1-12202)).
10.10	Increase and Joinder Agreement, dated as of March 10, 2015, among ONEOK Partners, L.P., Citibank, N.A., as administrative agent, and the other lenders parties thereto (incorporated by reference to Exhibit 10.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on March 10, 2015 (File No. 1-2202)).
10.11	Extension Agreement, dated August 1, 2012, among ONEOK Partners, L.P., as Borrower, the lenders party thereto and Citibank, N.A., as administrative agent, swingline lender and letter-of-credit issuer (incorporated by reference from Exhibit 10.1 to ONEOK Partners, L.P.'s Quarterly Report on 10-Q for the period ended June 30, 2011, filed on August 1, 2012 (File No. 1-12202)).

10.12	Credit Agreement, dated as of August 1, 2011, among ONEOK Partners, L.P., as borrower, the lenders party thereto, Citibank, N.A., as administrative agent, swingline lender and a letter-of-credit issuer, and Barclays Bank and Wells Fargo Bank, N.A., as letter-of-credit issuers (incorporated by reference from Exhibit 10.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on August 2, 2011 (File No. 1-12202)).
10.13	Guaranty Agreement, dated as of August 1, 2011, by ONEOK Partners Intermediate Limited Partnership in favor of the Citibank, N.A., as administrative agent (incorporated by reference from Exhibit 10.2 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on August 2, 2011 (File No. 1-12202)).
10.14	Underwriting Agreement, dated March 17, 2015, among ONEOK Partners, L.P. and ONEOK Partners Intermediate Limited Partnership and J.P. Morgan Securities LLC, Deutsche Bank Securities, Inc., Mitsubishi UFJ Securities (USA), Inc. and U.S. Bancorp Investments, Inc. as representatives of the several underwriters named therein (incorporated by reference to Exhibit 1.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on March 19, 2015 (File No. 1-12202)).
10.15	Common Unit Purchase Agreement dated February 28, 2012, between ONEOK Partners, L.P. and ONEOK, Inc. (incorporated by reference to Exhibit 1.2 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on March 2, 2012 (File No. 1-12202)).
10.16	Equity Distribution Agreement dated November 13, 2012, by and among ONEOK Partners, L.P. and Citigroup Global Capital Markets Inc. (incorporated by reference to Exhibit 1.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on November 13, 2012 (File No. 1-12202)).
10.17	Amendment No. 1 to Equity Distribution Agreement dated January 23, 2013, by and among ONEOK Partners, L.P. and Citigroup Global Markets Inc. (incorporated by reference to Exhibit 1.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on January 23, 2013 (File No. 1-12202)).
10.18	Underwriting Agreement, dated August 7, 2013, among ONEOK Partners, L.P. and Morgan Stanley & Co. LLC, Barclays Capital Inc., J.P. Morgan Securities LLC, UBS Securities LLC and Wells Fargo Securities, LLC, as representatives of the several underwriters named therein (incorporated by reference to Exhibit 1.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on August 12, 2013 (File No. 1-12202)).
10.19	Underwriting Agreement, dated September 9, 2013, among ONEOK Partners, L.P. and ONEOK Partners Intermediate Limited Partnership and RBS Securities Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated and Deutsche Bank Securities Inc., as representatives of the several underwriters named therein (incorporated by reference to Exhibit 1.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on September 12, 2013 (File No. 1-12202)).
10.20	Form of Indemnification Agreement between ONEOK Partners, L.P. and ONEOK, Partners GP L.L.C. officers and directors, as amended (incorporated by reference to Exhibit 10.20 to ONEOK Partners, L.P.'s Annual Report on Form 10-K for the fiscal year ended December 31, 2014, filed February 25, 2015 (File No. 1-12202)).
10.21	Equity Distribution Agreement, dated November 19, 2014, among ONEOK Partners, L.P., Citigroup Global Markets Inc., Barclays Capital Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Deutsche Bank Securities Inc., Goldman, Sachs & Co., Jefferies LLC, J.P. Morgan Securities LLC, Morgan Stanley & Co. LLC, Mitsubishi UFJ Securities (USA), Inc., RBC Capital Markets, LLC, UBS Securities LLC and Wells Fargo Securities, LLC (incorporated by reference to Exhibit 1.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on November 19, 2014 (File No. 1-12202)).
10.22	Common Unit Purchase Agreement dated August 11, 2015, between ONEOK Partners, L.P. and ONEOK, Inc. (incorporated by reference to Exhibit 1.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on August 17, 2015 (File No. 1-12202)).

10.23	Term Loan Agreement, dated as of January 8, 2016, among ONEOK Partners, L.P., Mizuho Bank, Ltd., as administrative agent and a lender, and the other lenders parties thereto (incorporated by reference to Exhibit 10.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on January 12, 2016 (File No. 1-12202)).
10.24	Guaranty Agreement, dated as of January 8, 2016, by ONEOK Partners Intermediate Limited Partnership in favor of Mizuho Bank, Ltd., as administrative agent, under the above-referenced Term Loan Agreement (incorporated by reference to Exhibit 10.2 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on January 12, 2016 (File No. 1-12202)).
10.25	Extension Agreement, dated as of January 29, 2016, among ONEOK Partners, L.P., Citibank, N.A., as administrative agent, swingline lender, a letter of credit issuer and a lender, and the other lenders and letter of credit issuers parties thereto (incorporated by reference to Exhibit 10.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on February 3, 2016 (File No. 1-12202)).
12	Computation of Ratio of Earnings to Fixed Charges for the years ended December 31, 2015, 2014, 2013, 2012 and 2011.
21	Required information concerning the registrant's subsidiaries.
23	Consent of Independent Registered Public Accounting Firm - PricewaterhouseCoopers LLP.
31.1	Certification of Terry K. Spencer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Derek S. Reiners pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Terry K. Spencer pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished only pursuant to Rule 13a-14(b)).
32.2	Certification of Derek S. Reiners pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished only pursuant to Rule 13a-14(b)).
99.1	Common Unit Purchase Agreement dated August 11, 2015, between ONEOK Partners, L.P. and Kayne Anderson MLP Investment Company, Kayne Anderson Energy Total Return Fund, Inc., Kayne Anderson Midstream/Energy Fund, Inc., Kayne Anderson Energy Development Company, KA First Reserve, LLC, Nationwide Mutual Insurance Company, Massachusetts Mutual Life Insurance Company, Kayne Anderson MLP Fund, L.P., Kayne Anderson Midstream Institutional Fund, L.P., Kayne Anderson Real Assets Fund, L.P., Kayne Institutional Energy Growth & Income Fund, L.P., Kayne Anderson Capital Income Partners (QP), L.P., Kayne Anderson Income Partners, L.P., KANTI (QP), L.P., Kayne Anderson Non-Traditional Investments, L.P., KARBO, L.P. and Kaiser Foundation Hospitals (incorporated by reference to Exhibit 99.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on August 17, 2015 (File No. 1-12202)).
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Calculation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definitions Document
101.LAB	XBRL Taxonomy Label Linkbase Document
101.PRE	XBRL Taxonomy Presentation Linkbase Document

Attached as Exhibit 101 to this Annual Report are the following XBRL-related documents: (i) Document and Entity Information; (ii) Consolidated Statements of Income for the years ended December 31, 2015, 2014 and 2013; (iii) Consolidated

Statements of Comprehensive Income for the years ended December 31, 2015, 2014 and 2013; (iv) Consolidated Balance Sheets at December 31, 2015 and 2014; (v) Consolidated Statements of Cash Flows for the years ended December 31, 2015, 2014 and 2013; (vi) Consolidated Statements of Changes in Equity for the years ended December 31, 2015, 2014 and 2013; and (vii) Notes to Consolidated Financial Statements. We also make available on our website the Interactive Data Files submitted as Exhibit 101 to this Annual Report.

The total amount of securities of the Partnership authorized under any instrument with respect to long-term debt not filed as an exhibit does not exceed 10 percent of the total assets of the Partnership and its subsidiaries on a consolidated basis. The Partnership agrees, upon request of the SEC, to furnish copies of any or all of such instruments to the SEC.

Signatures

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

ONEOK Partners, L.P.
By: ONEOK Partners GP, L.L.C., its General Partner

Date: February 23, 2016

By: /s/ Derek S. Reiners
Derek S. Reiners
Senior Vice President,
Chief Financial Officer and Treasurer
(Signing on behalf of the Registrant)

Pursuant to the requirements of the Exchange Act, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on this 23rd day of February 2016.

/s/ John W. Gibson John W. Gibson Chairman of the Board	/s/ Terry K. Spencer Terry K. Spencer President, Chief Executive Officer and Director
/s/ Derek S. Reiners Derek S. Reiners Senior Vice President, Chief Financial Officer and Treasurer	/s/ Sheppard F. Miers III Sheppard F. Miers III Vice President and Chief Accounting Officer
/s/ Julie H. Edwards Julie H. Edwards Director	/s/ Michael G. Hutchinson Michael G. Hutchinson Director
/s/ Steven J. Malcolm Steven J. Malcolm Director	/s/ Jim W. Mogg Jim W. Mogg Director
/s/ Gary N. Petersen Gary N. Petersen Director	/s/ Craig F. Strehl Craig F. Strehl Director

BOARD OF DIRECTORS

JULIE H. EDWARDS
Former Chief Financial Officer, Southern Union Company;
Former Chief Financial Officer, Frontier Oil Corporation
Houston, Texas

JOHN W. GIBSON
Chairman of the Board and Retired Chief Executive Officer,
ONEOK Partners, L.P. and ONEOK, Inc.
Tulsa, Oklahoma

MICHAEL G. HUTCHINSON
Retired Partner, Deloitte & Touche
Denver, Colorado

STEVEN J. MALCOLM
Retired Chairman, President and Chief Executive Officer,
The Williams Companies, Inc.
Tulsa, Oklahoma

JIM W. MOGG
Retired Chairman, DCP Midstream GP, L.L.C.
Hydro, Oklahoma

GARY N. PETERSEN
Former President and Chief Operating Officer,
Reliant Energy-Minnegasco;
Retired President, Endres Processing LLC
Minneapolis, Minnesota

TERRY K. SPENCER
President and Chief Executive Officer,
ONEOK Partners, L.P. and ONEOK, Inc.
Tulsa, Oklahoma

CRAIG F. STREHL
Chief Operating Officer and Partner,
LONESTAR Midstream Partners
New Castle, New Hampshire

OFFICERS Positions as of March 1, 2016 • Ages as of December 31, 2015

ONEOK PARTNERS

TERRY K. SPENCER, 56
President and Chief Executive Officer

ROBERT F. MARTINOVICH, 58
Executive Vice President and Chief Administrative Officer

WALTER S. HULSE III, 51
Executive Vice President, Strategic Planning
and Corporate Affairs

WESLEY J. CHRISTENSEN, 62
Senior Vice President, Operations

STEPHEN W. LAKE, 52
Senior Vice President, General Counsel and
Assistant Secretary

DEREK S. REINERS, 44
Senior Vice President, Chief Financial Officer
and Treasurer

CHARLES M. KELLEY, 57
Senior Vice President, Corporate Planning
and Development

SHERIDAN C. SWORDS, 46
Senior Vice President, Natural Gas Liquids

KEVIN L. BURDICK, 51
Senior Vice President, Natural Gas Gathering and Processing

J. PHILLIP MAY, 53
Senior Vice President, Natural Gas Pipelines

SHEPPARD F. MIERS III, 47
Vice President, Chief Accounting Officer

ERIC GRIMSHAW, 63
Vice President, Associate General Counsel
and Corporate Secretary

ONEOK, INC.

TERRY K. SPENCER, 56
President and Chief Executive Officer

ROBERT F. MARTINOVICH, 58
Executive Vice President and Chief Administrative Officer

WALTER S. HULSE III, 51
Executive Vice President, Strategic Planning
and Corporate Affairs

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J. PHILLIP MAY, 53
Senior Vice President, Natural Gas Pipelines

SHEPPARD F. MIERS III, 47
Vice President, Chief Accounting Officer

ERIC GRIMSHAW, 63
Vice President, Associate General Counsel
and Corporate Secretary

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