2014 CONTINUING OUR STRATEGIC GROWTH.

ONEOK PARTNERS, L.P. ANNUAL REPORT

ONEOK PARTNERS

ONEOK Partners, L.P. (pronounced ONE-OAK) is a publicly traded master limited partnership engaged in the natural gas gathering and processing, natural gas liquids and natural gas pipelines businesses.

Our sole general partner is a subsidiary of ONEOK, Inc., an energy company founded in 1906 that as of December 31, 2014, owns 37.8 percent of the partnership.

FINANCIAL HIGHLIGHTS

YEAR ENDED DECEMBER 31, 2014		2014		2013		2012
Consolidated financial information (millions of dollars)						
Net margin	$	2,103.1	$	1,647.1	$	1,641.8
Operating income	$	1,148.8	$	900.7	$	962.9
Net income attributable to ONEOK Partners, L.P.	$	910.3	$	803.6	$	888.0
Total assets	$	14,634.5	$	12,862.6	$	10,959.2
Total debt-to-capitalization		54%		55%		52%
Capital expenditures (millions of dollars)						
Growth	$	1,619.1	$	1,846.8	$	1,458.3
Maintenance	$	126.9	$	92.5	$	102.2
Total capital expenditures	$	1,746.0	$	1,939.3	$	1,560.5
Common unit data						
Common units outstanding at year-end		180,826,973		159,007,854		146,827,354
Class B units outstanding at year-end		72,988,252		72,988,252		72,988,252
Total units outstanding at year-end		253,815,225		231,996,106		219,815,606
Distributions declared per limited partner unit	$	3.07	$	2.89	$	2.69
Market price range						
High	$	59.43	$	60.59	$	61.23
Low	$	38.23	$	47.10	$	51.16
Year-end	$	39.63	$	52.65	$	53.99

Reconciliation of Net Income to EBITDA and Distributable Cash Flow (millions of dollars)		2014		2013		2012
Net income	$	911	$	804	$	888
Interest expense		282		237		206
Depreciation and amortization		291		237		203
Impairment charges		76		-		-
Income taxes		13		11		10
Allowance for equity funds used during construction		(15)		(31)		(13)
Adjusted EBITDA		1,558		1,258		1,294
Interest expense		(282)		(237)		(206)
Maintenance capital		(127)		(92)		(102)
Equity earnings from investments		(41)		(111)		(123)
Impairment charges		(76)		-		-
Distributions received from unconsolidated affiliates		139		137		156
Other		(2)		(6)		(11)
Distributable cash flow	$	1,169	$	949	$	1,008

ON THE COVER: *Garden Creek III natural gas processing facility in western North Dakota*

LETTER TO UNITHOLDERS

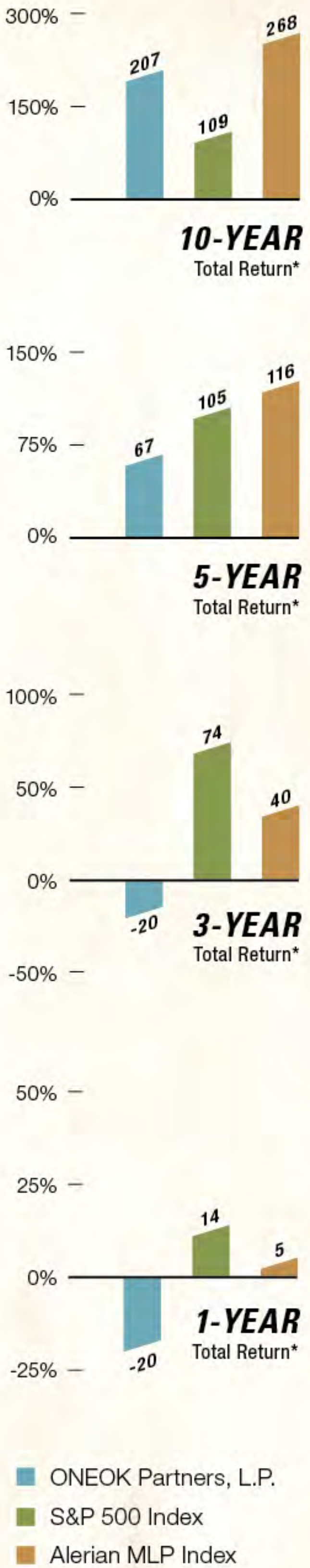
Growing Strategically to Serve Our Stakeholders

In 2014, we continued our disciplined growth strategy, using completed projects as a springboard for additional growth across our operating footprint. Through organic growth and acquisitions, we added strategic assets in the natural gas liquids (NGL)-rich regions of North Dakota's Williston Basin, Wyoming's Powder River Basin, the Permian Basin in West Texas and southeastern New Mexico, and Kansas and Oklahoma in the Mid-Continent region. Our producer customers concentrated their drilling in these productive regions in 2014 and, as in years past, we remained committed to building the essential midstream infrastructure needed to gather, transport, process and store natural gas and NGLs from these areas.

This strategy to organically grow and expand our capabilities has been in process since 2006, when ONEOK became the sole general partner of Northern Border Partners and renamed it ONEOK Partners. To position ourselves as the multiservice midstream provider of choice in the regions where we operate, we've built or acquired seven new natural gas processing facilities, built or expanded three NGL fractionators and constructed thousands of miles of natural gas and NGL pipelines from 2006 to 2014.

This strategic growth demonstrates our commitment to providing responsive, flexible service to our customers. From 2010 to 2014, we executed nearly $6 billion in capital-growth projects and acquisitions in our natural gas and natural gas liquids business segments that resulted in increased natural gas and NGL volumes on our extensive 36,000-mile integrated pipeline network. In 2014 alone, we completed approximately $3.2 billion in capital-growth projects and acquisitions, including:

- The Sterling III Pipeline, our fourth NGL pipeline connecting the Mid-Continent and Gulf Coast NGL market centers;
- The Canadian Valley natural gas processing plant in western Oklahoma;
- An ethane/propane splitter in Mont Belvieu, Texas;



As of December 31, 2014

**Total return represents unit-price appreciation and the reinvestment of distributions.*

- » The Garden Creek II natural gas processing plant in North Dakota;
- » The first expansion of the Bakken NGL Pipeline;
- » The Niobrara NGL Lateral that connects our natural gas gathering and processing infrastructure in NGL-rich areas of the Powder River Basin to our nearby Bakken NGL Pipeline;
- » The Garden Creek III natural gas processing plant in North Dakota;
- » The acquisition of the West Texas LPG pipeline system, which includes approximately 2,600 miles of NGL pipelines and related assets in the Permian Basin; and
- » The MB-3 NGL fractionator in Mont Belvieu.

As a result of completed capital-growth projects and acquisitions, distributions declared to unitholders have increased at an 8 percent compound annual growth rate since 2010. In 2014, we increased the distribution declared to $3.07, compared with $2.89 in 2013, creating value for you, our unitholders.

We anticipate that incremental earnings from the completion of projects from this capital-growth program will allow us to increase the distribution declared by 3 to 5 percent in 2015 compared with 2014, subject to board approval. *(See page 24-25 of this report for more information on ONEOK Partners' capital-growth program.)*

2014 FINANCIAL PERFORMANCE

Despite the volatile fourth-quarter commodity price environment, ONEOK Partners reported a record year in 2014, with all of our business segments experiencing double-digit operating income growth compared with 2013.

2014 net income attributable to ONEOK Partners was $910.3 million, or $2.33 per unit, compared with $803.6 million, or $2.35 per unit, in 2013. These results include a noncash impairment charge of $76.4 million, or 31 cents per unit, in the natural gas gathering and processing segment.

2014 adjusted earnings before interest, taxes, depreciation and amortization (adjusted EBITDA) was $1.56 billion, a 24 percent increase compared with $1.26 billion in 2013. Distributable cash flow (DCF) for 2014 was $1.17 billion, providing 1.10 times coverage, compared with DCF of $949.2 million that provided 1.03 times coverage in 2013.

Canadian Valley natural gas processing facility in western Oklahoma

COMMODITY PRICE VOLATILITY

A weakened and volatile commodity price environment is creating challenges for our producer customers as they assess their future drilling plans. The industry has experienced this down cycle many times, and we remain confident that our business model and our vision will prevail in these uncertain times. Our business, with its reliable and extensive 36,000-mile integrated pipeline network and significant platform of fee-based services, has weathered these cycles before.

In such times, it is important to answer the difficult questions that arise. *Are we managing financial resources in a disciplined manner? What adjustments need to be made to our strategy? How are our customers being affected? What can we draw on from past down-cycle experiences?*

After reassessing our producer customers' updated supply development plans, we made the decision to suspend capital spending on certain capital-growth projects with the knowledge that natural gas and NGL volumes may not grow as fast as previously forecast. While we remain committed to our organic growth strategy and increasing unitholder distributions, managing capital resources in this volatile commodity price environment is paramount.

Due to lower commodity prices and our producer customers' reduced drilling plans, ONEOK Partners is suspending capital expenditures for the following announced capital-growth projects:

» The Demicks Lake natural gas processing plant and related infrastructure in the Williston Basin in North Dakota;

» The Knox natural gas processing plant and related infrastructure in the Mid-Continent region in Oklahoma; and

» The Bronco natural gas processing plant in the Powder River Basin in Wyoming.

We expect to resume these suspended capital-growth projects and update the completion dates as soon as market conditions warrant. With the planning and development we've completed, we expect to quickly resume these projects as our producer customer needs for future capacity dictate.

The 200-million cubic feet per day (MMcf/d) Lonesome Creek plant in McKenzie County, North Dakota, and the 80-MMcf/d Bear Creek plant in Dunn County, North Dakota, remain on schedule to be completed in the fourth quarter 2015 and the third quarter 2016, respectively.

Even in the face of significant reductions in our producer customers' drilling budgets, we still expect considerable year-over-year volume growth as producers continue to drill in the most productive areas of their dedicated acreage.

Understanding the ever-changing needs of our customers – petrochemical companies, producers, refineries and natural gas distribution companies to name a few – and developing creative solutions for their challenges will ensure we continue offering the reliable service our customers have come to expect from us, and that we demand of ourselves.

We continually work to improve efficiency and optimize costs, and to remove volatility and improve stability in the business. As an example, we restructured our business model more than 10 years ago to shift away from contracts with higher commodity price exposure to a more fee-based business model. Through creative contracting with our customers, we continue to find opportunities to enhance the services we provide to our customers and to increase fee-based earnings. The acquisition of the West Texas LPG pipeline system in the Permian Basin is an example of where we have added significant opportunities to grow our fee-based earnings.

2015 REVISED GUIDANCE

In February 2015, we provided a revised 2015 outlook, replacing all previously announced guidance expectations and financial forecasts. We reduced our 2015 adjusted EBITDA guidance to a range of $1.51 billion to $1.73 billion, compared with the previous guidance range of $1.77 billion to $1.99 billion announced on December 2, 2014.

This reduction is due to significantly lower natural gas and NGL prices, particularly ethane and propane. However, 2015 natural gas volumes gathered and processed are expected to grow approximately 10 percent and 8 percent, respectively, compared with 2014, as we benefit from a backlog of new well connections, continued drilling in core areas of the Bakken and Cana-Woodford shales, and as we continue to assist oil producers in their ongoing efforts to reduce the flaring of natural gas in the Williston Basin.

In addition, we reduced 2015 net income attributable to ONEOK Partners guidance to $845 million to $1.01 billion, compared with the previous guidance range of $1.12 billion to $1.28 billion. Our DCF is expected to be in the range of $1.08 billion to $1.26 billion, compared with the previous guidance range of $1.31 billion to $1.49 billion. 2015 revised guidance now includes a projected 3 to 5 percent increase in unitholder distributions declared compared with 2014, subject to ONEOK Partners board approval, compared with our previous guidance of an 8 percent increase.

Natural gas storage facility near Edmond, Oklahoma

CULTIVATING A CULTURE

What our dedicated team of employees has accomplished over the past year – and several years – truly is remarkable. As we have grown our operations and added natural gas processing plants, pipelines, NGL fractionators and other midstream infrastructure, it has been our employees who have come up with creative solutions to the operational and technical challenges of our systems. We appreciate their efforts to ensure that we operate safely, reliably and in an environmentally responsible manner.

To be successful, we must provide our employees and leaders with the resources and development they need to learn and grow. That's why in 2014 we designed and launched a comprehensive Leadership Development Strategy to create and cultivate a high-performing, diverse, learning organization that is collaborative, accountable and innovative. Leaders at every level of the company are participating in the strategy to improve interaction and communication between leaders and employees and to strengthen our competitive advantage.

At ONEOK Partners, we know that including, not excluding, diverse thoughts and opinions is key to our continued success. We make better decisions when we listen to the thoughts and opinions of others and don't rely solely on our own expertise. Diverse points of view are critical to decisions we make about the company. The Diversity and Inclusion Strategy we launched in 2014 will foster that culture of inclusion throughout the company.

We remain focused on operating our assets safely, reliably and environmentally responsibly and searching for creative ways to meet the ever-changing needs of our customers.

While the current environment presents challenges, our opportunities for continued growth look favorable as we continue executing on our vision. We have uniquely positioned strategic assets with strong growth prospects and a long, rich history of our dedicated and experienced employees providing quality service to our customers.

We would like to recognize Gil J. Van Lunsen, who after 10 years of loyal and dedicated service will retire from our board of directors in April 2015. ONEOK Partners experienced unprecedented growth during Gil's tenure, and we are thankful for his invaluable leadership that helped shape the partnership into what it is today.

The important work we have accomplished in recent years and in 2014 has made ONEOK Partners well positioned and ready for the opportunities and challenges that lay ahead in 2015.

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

John W. Gibson
CHAIRMAN

Terry K. Spencer
PRESIDENT AND CHIEF EXECUTIVE OFFICER

MARCH 12, 2015

Garden Creek II natural gas processing facility in western North Dakota

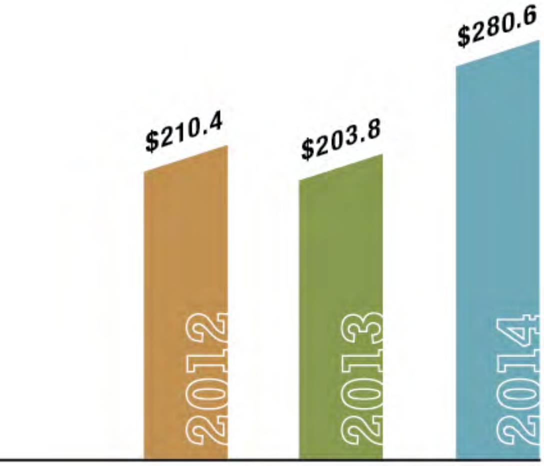
ONEOK PARTNERS INTEGRATED NETWORK

ONEOK Partners operates an extensive 36,000-mile integrated natural gas and natural gas liquids pipeline network positioned in growing basins and major market areas.

NATURAL GAS GATHERING & PROCESSING

2014 FINANCIAL RESULTS REFLECT

- ***A $147.6 million increase** due primarily to natural gas volume growth in the Williston Basin and the Cana-Woodford Shale, and increased ownership in the Maysville, Oklahoma, natural gas processing plant, which resulted 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 $11.3 million increase** due primarily to higher net realized natural gas and NGL prices;*
- ***An $8.8 million increase** due primarily to changes in contract mix; and*
- ***A $6.4 million decrease** due to a condensate contract settlement in 2013.*



OPERATING INCOME
Millions of Dollars

In 2014, we continued to expand our natural gas processing capacity across multiple supply basins to accommodate increasing production within our operating footprint.

Since 2010, we have constructed or announced 11 new natural gas processing facilities and related infrastructure – totaling nearly 1.6 billion cubic feet per day (Bcf/d) of natural gas processing capacity – in multiple natural gas liquids (NGL)-rich areas, including the Williston Basin in North Dakota, the NGL-rich area of Wyoming's Powder River Basin and the Cana-Woodford and SCOOP (South Central Oklahoma Oil Province) plays in Oklahoma.

Today, we operate 19 active natural gas processing plants with 1.45 Bcf/d of natural gas processing capacity and more than 18,700 miles of natural gas gathering pipelines. Our operations are supported by significant acreage dedications, much of which are in core, higher-return areas where drilling remains economical even in the current lower commodity price environment.

2014 operating income in this segment was $280.6 million – a 38 percent increase compared with 2013 – as completed capital-growth projects resulted in natural gas volume growth in the Williston Basin and the Cana-Woodford Shale.

Across our operating system, natural gas volumes gathered increased by 29 percent, and natural gas volumes processed from our natural gas processing facilities increased by 40 percent in 2014 compared with 2013.

Garden Creek III natural gas processing facility in western North Dakota

EXPANDING CAPACITY TO MEET CUSTOMERS' NEEDS

Developing creative, innovative, flexible and cost-effective ways to meet the ever-changing needs of our customers remains a high priority. In 2014, we completed three new natural gas processing facilities and related infrastructure with a combined natural gas processing capacity of 400 million cubic feet per day (MMcf/d) – increasing our natural gas processing capacity systemwide to 1.45 Bcf/d.

Completed in March 2014, the 200-MMcf/d Canadian Valley natural gas processing plant in the heart of the resurgent Cana-Woodford Shale is our largest such facility in Oklahoma and increased our natural gas processing capacity in the state to approximately 700 MMcf/d.

The 100-MMcf/d Garden Creek II and Garden Creek III plants in McKenzie County, North Dakota, were completed in August and October 2014, respectively, and increased our Williston Basin natural gas processing capacity to approximately 600 MMcf/d.

The 200-MMcf/d Lonesome Creek plant in McKenzie County, North Dakota, and the 80-MMcf/d Bear Creek plant in Dunn County, North Dakota, are on schedule to be completed in the fourth quarter 2015 and the third quarter 2016, respectively.

We also are constructing natural gas compression to take advantage of additional natural gas processing capacity at the Garden Creek and Stateline natural gas processing plants in the Williston Basin. Once these projects are completed in the third quarter 2016, our natural gas processing capacity in the region will be nearly 1 Bcf/d. *(For more information on ONEOK Partners' capital-growth projects, see pages 24–25.)*

The construction of essential natural gas infrastructure in the Williston Basin is an important part of the solution to reduce natural gas flaring by oil producers in the region. Since 2010, we have completed or announced eight new natural gas processing plants and related natural gas gathering infrastructure in the Williston Basin.

The added natural gas processing capacity in these NGL-rich regions also has created the need for more NGL infrastructure to accommodate growing NGL volumes from our natural gas plants. ONEOK Partners' natural gas liquids business is investing $300 million to $345 million to build NGL transportation and fractionation infrastructure to provide producer customers with flexibility for their marketable NGL products through our integrated system.

REDUCING NORTH DAKOTA NATURAL GAS FLARING

ONEOK Partners is the largest independent natural gas gatherer and processor in the Williston Basin. Our natural gas gathering system in this region consists of more than 6,500 miles, and there are more than 3 million acres, or approximately 60 percent of the 5 million available acres, where natural gas production is dedicated to our systems. Producers there continue to focus their drilling in the Bakken Shale and Three Forks formations that yield crude oil and NGL-rich natural gas.

The North Dakota Industrial Commission (NDIC) reported that crude oil production in the Williston Basin exceeded 1 million barrels per day (bpd) in 2014 and is expected to grow to more than 1.5 million bpd by 2021. Natural gas produced in association with crude oil exceeded 1.4 Bcf/d in 2014.

In many areas of North Dakota, natural gas production exceeds the capacity of existing gathering and processing infrastructure, causing natural gas to be flared by oil producers. However, ongoing construction of essential natural gas infrastructure in North Dakota has substantially decreased the percentage of natural gas volumes flared.

NATURAL GAS GATHERING & PROCESSING

In early 2014, the NDIC set natural gas flaring-reduction targets, including goals to reduce flaring in the state to 15 percent of natural gas production by January 2016 and to 10 percent by October 2020. In December 2014, the NDIC reported that 24 percent of the natural gas produced in the state was flared, compared with more than 30 percent at various times in 2013 and 2014.

We actively participate in an industry task force created to address and reduce natural gas flaring in North Dakota. The task force – composed of midstream providers and producers – is charged with identifying solutions to the technical, regulatory and infrastructure challenges facing the industry in reducing natural gas flaring.

One accomplishment of the task force was the recommendation of natural gas-capture plans, which detail how producers will capture natural gas produced at the wellhead and transport it to a natural gas plant for processing. The NDIC now requires producers to file a natural gas-capture plan before they receive a drilling permit.

ADDING OKLAHOMA NATURAL GAS PROCESSING CAPACITY

For decades, ONEOK Partners has maintained a natural gas gathering and processing presence in central and western Oklahoma, where our natural gas processing capacity totals approximately 700 MMcf/d. We have strong positions in areas of the state now experiencing significant growth – particularly the Cana-Woodford Shale and the SCOOP play – including more than 500,000 net acres where natural gas production is dedicated to our systems.

Producers continued to actively develop the Cana-Woodford Shale in 2014, as enhanced well-completion technology improved efficiency and led to higher production rates. To accommodate the increased production in this region, we completed in March 2014 our largest natural gas processing facility in Oklahoma – the 200-MMcf/d Canadian Valley plant in the heart of this prolific shale.

REVISING CAPITAL-GROWTH PROJECT GUIDANCE

After reassessing our producer customers' updated supply development plans, we made the decision to suspend capital spending on certain capital-growth projects due to lower commodity prices and our producer customers' reduced drilling plans. With the planning and development we have completed to date, we expect to quickly resume these projects as customer needs dictate and market conditions warrant. The expected completion dates will be updated once these projects are resumed.

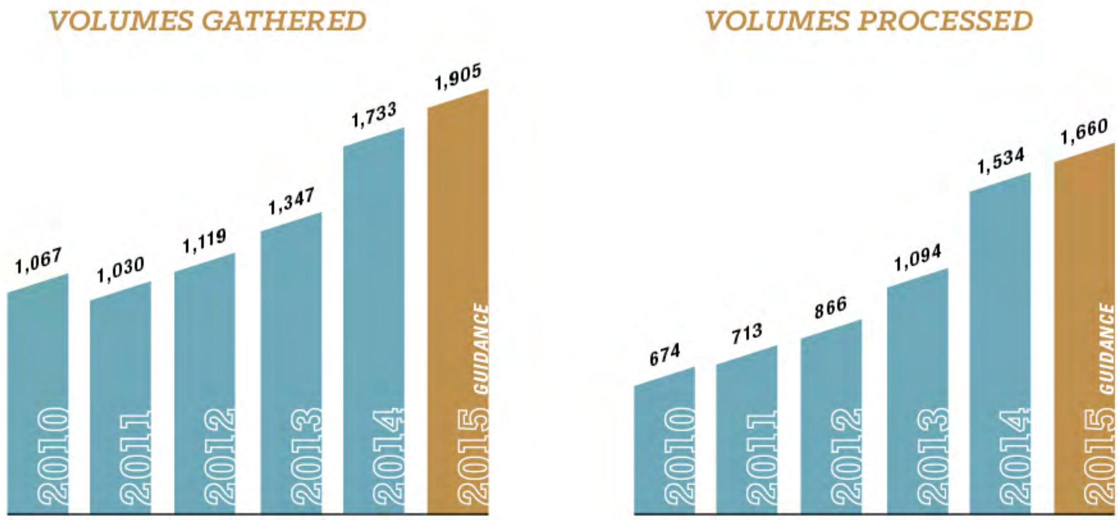
We are suspending capital expenditures for the following announced capital-growth projects:

- The Demicks Lake natural gas processing plant and related infrastructure in the Williston Basin in North Dakota;
- The Knox natural gas processing plant and related infrastructure in the Mid-Continent region in Oklahoma; and
- The Bronco natural gas processing plant and related infrastructure in the Powder River Basin in Wyoming.

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

INCREASING NATURAL GAS VOLUMES

From 2010 through 2014, our natural gas volumes gathered increased by 62 percent, and natural gas volumes processed more than doubled. We estimate that 2015 natural gas gathered volumes will increase more than 10 percent, and natural gas volumes processed will increase 8 percent, compared with 2014, as announced capital-growth projects are completed.



NATURAL GAS VOLUME GROWTH
Billion British thermal units per day (BBtu/d)

NATURAL GAS LIQUIDS

Producers continue to actively develop natural gas liquids (NGL)-rich resources, adding new NGL supply to our systems in the Williston Basin in North Dakota and Montana, the Cana-Woodford Shale and SCOOP play in Oklahoma, the NGL-rich Niobrara Shale formation in Wyoming's Powder River Basin and the Permian Basin in Texas.

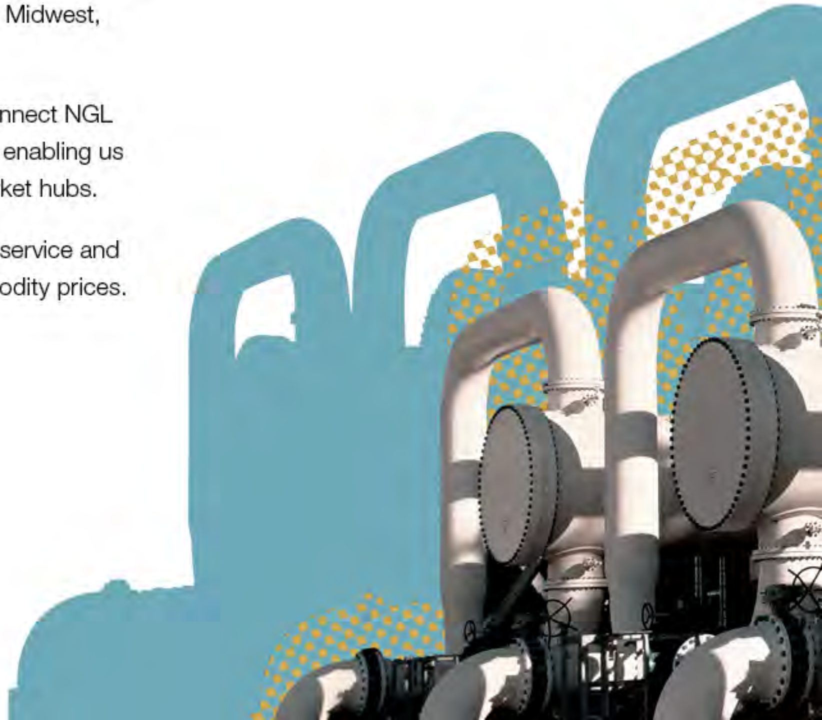
Completed capital-growth projects and the acquisition of NGL assets in the Permian Basin of West Texas and southeastern New Mexico enhance the natural gas liquids segment's operating flexibility and provide customers access to additional markets for their products.

In 2014, this segment reported record financial results that included operating income of $689.0 million, a 26 percent increase compared with 2013. Increases in fee-based exchange-services margins from higher margin NGL volumes gathered and higher fees from contract renegotiations for NGL exchange-services activities were offset by narrower NGL price differentials and ethane rejection.

Our nondiscretionary NGL gathering, fractionation, transportation, storage and marketing services enable NGL producers and natural gas processors to convert their unfractionated NGLs into marketable NGL purity products and deliver them to wholesalers, petrochemical facilities and refineries in the Mid-Continent, Chicago and the upper Midwest, and the Texas Gulf Coast.

Our vertically integrated and strategically located assets connect NGL market hubs in Conway, Kansas, and Mont Belvieu, Texas, enabling us to maximize the value of NGL products between these market hubs.

We continue to increase our primarily fee-based exchange service and storage businesses, which are not as dependent on commodity prices.

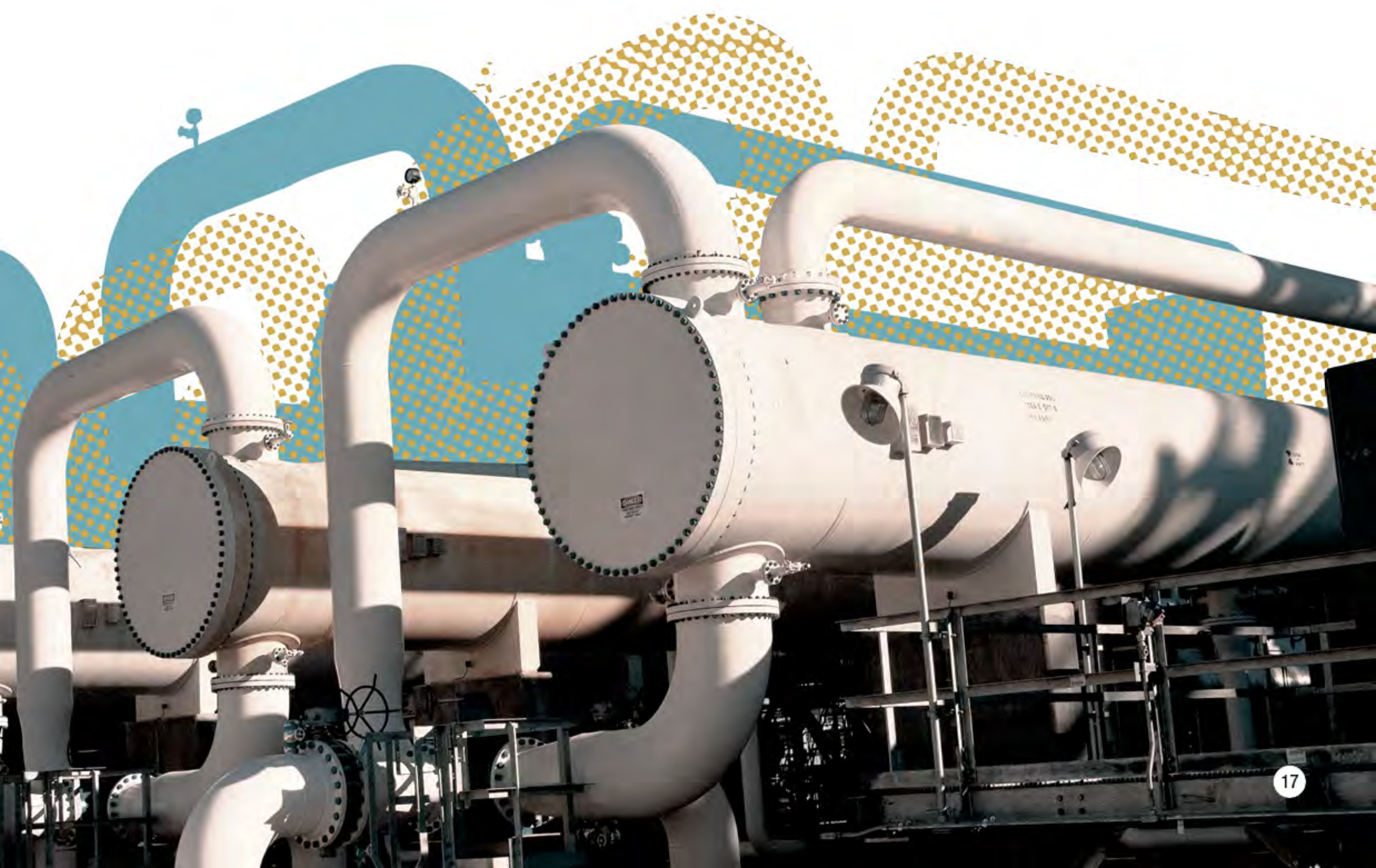


MB-2 NGL fractionator in Mont Belvieu, Texas

2014 FINANCIAL RESULTS REFLECT

- ***A $157.4 million increase*** *in fee-based exchange-services margins, resulting primarily from increased volumes from new natural gas processing plants connected in the Williston Basin and Mid-Continent regions, and higher fees from contract renegotiations for NGL exchange-services activities, offset partially by lower volumes from the termination of a contract;*
- ***A $79.8 million increase*** *in optimization and marketing margins, resulting from a $31.4 million increase due primarily to wider NGL product price differentials; a $25.2 million increase in marketing margins, 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;*
- ***A $22.8 million increase*** *from higher isomerization volumes, resulting from wider NGL product price differentials between normal butane and iso-butane;*
- ***An $18.3 million decrease*** *from the impact of ethane rejection, which resulted in lower NGL volumes; and*
- ***A $6.0 million decrease*** *from the impact of lower operational measurement gains.*

OPERATING INCOME
Millions of Dollars



NATURAL GAS LIQUIDS

ACQUIRING STRATEGIC PERMIAN BASIN ASSETS

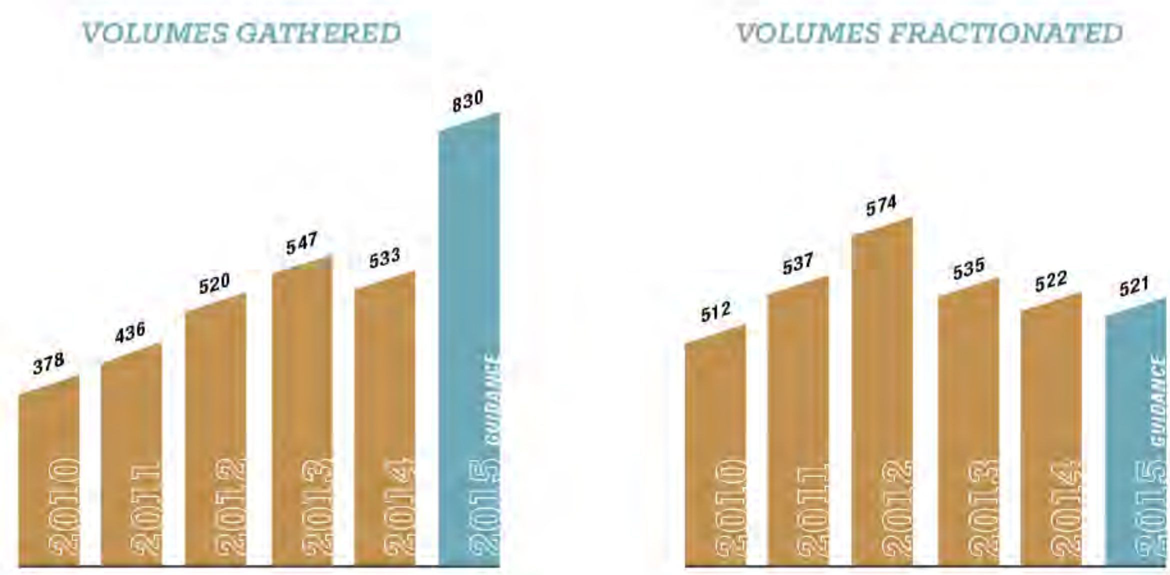
In late 2014, we completed the acquisition of NGL pipelines and related assets from affiliates of Chevron Corporation for approximately $800 million. Included in the transaction was an 80 percent interest in the West Texas LPG Pipeline Limited Partnership and 100 percent interest in the Mesquite Pipeline that consist collectively of approximately 2,600 miles of NGL gathering pipelines extending from the Permian Basin in southeastern New Mexico to East Texas and Mont Belvieu. The acquisition increased our NGL gathering system mileage by more than 60 percent, and NGL volumes gathered are expected to increase more than 50 percent.

This diverse NGL gathering system integrates well with our existing assets, provides additional fee-based earnings and adds a strategic supply basin for our growing NGL system. We now can provide bundled services – transportation, fractionation and storage – to existing customers in the Permian Basin, strengthening our competitive position.

RESPONDING TO MARKET CONDITIONS

The flexibility of our extensive NGL system enables us to respond to market fluctuations driven by supply and demand. An example of this fluctuation occurred in early 2014 when sustained, unseasonably cold temperatures, coupled with higher demand in the fall of 2013 for propane used for crop-drying purposes, resulted in unprecedented propane conditions in the Midwest, including depleted supply and record propane prices.

With our flexible market connectivity between the Conway and Mont Belvieu hubs, we were able to deliver much-needed propane to the Midwest markets during this period.



NATURAL GAS LIQUIDS VOLUME GROWTH
Thousand barrels per day (MBbls/d)

NGL VOLUMES

From 2010 through 2014, NGL volumes gathered on our NGL system – one of the largest in the nation – have increased 41 percent, and NGL volumes fractionated have increased 2 percent. As a result of the acquisition of the West Texas LPG pipeline system and the completion of several capital-growth projects, we estimate that our 2015 NGL volumes gathered will increase by 56 percent compared with 2014.

EXPANDING THE BAKKEN NGL PIPELINE

The Bakken NGL Pipeline is a 600-mile pipeline that transports unfractionated NGLs from the Williston Basin to an interconnection with our 50 percent-owned Overland Pass Pipeline in northern Colorado, and then on to our Mid-Continent NGL fractionation and storage facilities in central Kansas. From there, these NGLs ultimately are transported to the Texas Gulf Coast or to Midwest markets, including Chicago, through our NGL assets – just one example of the value of our integrated system at work.

In September 2014, we installed additional pump stations to increase the capacity of the Bakken NGL Pipeline to 135,000 barrels per day (bpd) from its original capacity of 60,000 bpd. To accommodate growing NGL volumes produced at our natural gas processing plants in the Williston Basin, a second expansion will increase its capacity to 160,000 bpd by the second quarter 2016.

The Niobrara NGL Lateral, completed in September 2014, connects our natural gas gathering and processing business' Sage Creek plant, located in the NGL-rich Niobrara Shale formation in Wyoming's Powder River Basin, with the nearby Bakken NGL Pipeline.

We also built a 95-mile NGL pipeline that connects our Hutchinson, Kansas, NGL facilities to similar facilities in Medford, Oklahoma, and completed modifications to existing NGL fractionation and storage facilities at Hutchinson. The new pipeline and modified NGL infrastructure were completed in the first quarter 2015 and are designed to accommodate additional NGLs added to our system from the Williston Basin and Mid-Continent.

BUILDING THE STERLING III PIPELINE AND INCREASING GULF COAST NGL FRACTIONATION CAPACITY

In March 2014, we completed the Sterling III NGL Pipeline, a 540-mile pipeline with the capacity to transport 193,000 bpd of either unfractionated NGLs or NGL purity products between our Mid-Continent NGL infrastructure and similar facilities on the Gulf Coast in Mont Belvieu, Texas. The Sterling III Pipeline parallels our existing Sterling I and Sterling II NGL distribution pipelines, which also were reconfigured to transport either unfractionated NGLs or NGL purity products. These projects enhanced our flexibility to move unfractionated NGLs and NGL purity products between market centers.

We expanded our Gulf Coast NGL fractionation capacity to meet growing demand from petrochemical companies for ethane and propane as feedstocks. In December 2014, we completed the 75,000-bpd MB-3 NGL fractionator, our third NGL fractionator in Mont Belvieu. We also own MB-2, a 75,000-bpd NGL fractionator, and own an 80 percent interest in and operate MB-1, a 160,000-bpd NGL fractionator. We also have a long-term, third-party fractionation-services agreement for an additional 60,000 bpd of fractionation capacity at Mont Belvieu.

In addition, we installed a new ethane/propane (E/P) splitter at our Mont Belvieu NGL storage facility in March 2014 to split E/P mix into purity ethane and purity propane to meet the growing needs of petrochemical customers.

MB-3 NGL fractionator in Mont Belvieu, Texas

NATURAL GAS PIPELINES

2014 FINANCIAL RESULTS REFLECT

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

OPERATING INCOME
Millions of Dollars

Our primarily fee-based natural gas pipelines segment provides reliable midstream transportation and storage services to local natural gas distribution companies, electric-generation plants, producers and large industrial customers, primarily under long-term, firm-demand contracts.

We connect North American supply basins with major market and trading hubs through our extensive network of 6,700 miles of interstate and intrastate natural gas pipelines, and provide natural gas storage capacity of approximately 52 billion cubic feet (Bcf).

This segment remains an important part of our diverse midstream business, generating stable fee-based operating income and cash flows. 2014 operating income for this segment increased 19 percent, to $181.0 million, compared with 2013. 2014 equity income, primarily from our 50 percent ownership of Northern Border Pipeline, was $69.8 million, a 7 percent increase compared with 2013.

Earnings in this segment are primarily fee-based, with approximately 92 percent of our natural gas pipeline transportation capacity and 76 percent of our natural gas storage capacity contracted on a firm basis in 2015.

STRATEGICALLY LOCATED AND POSITIONED FOR SUCCESS

Due to economic and environmental factors, electric-generation companies continue to rely more on natural gas to produce electricity for their customers. As natural gas continues to be the low-cost and environmentally friendly fuel of choice, we are well-positioned to provide flexible natural gas storage and transportation services to these electric utilities as they convert their facilities to natural gas from coal.

Natural gas storage facility near Edmond, Oklahoma

Our natural gas pipelines segment's assets are well-positioned to benefit from this conversion trend, with approximately 35 existing coal-fired, electric-generation plants representing more than 26,000 megawatts of capacity within 20 miles of our natural gas pipelines.

Growing production in the Utica and Marcellus shale areas has created additional transportation needs to reach markets in Chicago and the upper Midwest. Our assets are strategically located to provide producers with options to transport their natural gas to these markets. The recently announced 125-million cubic feet per day (MMcf/d) expansion of our Midwestern Gas Transmission system now underway includes the construction of a new compressor station in Herscher, Illinois, which is scheduled to be in service in the fourth quarter 2015. Midwestern Gas Transmission connects to many major interstate pipeline systems to provide bi-directional service to markets in Tennessee, Kentucky, Indiana, southern Illinois and Chicago.

GROWING EXPORTS TO MEXICO

The growing demand for natural gas in Mexico is an opportunity for our natural gas pipelines segment to deliver natural gas supply to new international markets. In late 2014, we held a nonbinding open season for a proposed project that includes approximately 200 miles of 30-inch intrastate pipeline to transport natural gas from the Permian Basin to the Mexican border. We have evaluated the results of the open season and are in the process of securing commitments from the market.

The proposed pipeline would extend from our ONEOK WesTex Transmission natural gas pipeline system near Coyanosa, Texas, to a new international border crossing connection at the Mexican border near San Elizario, Texas.

The proposed pipeline would be constructed in three phases. The first phase is expected to be in service in the first quarter 2016, while the second phase is expected to be in service in the first quarter 2017. The third and final phase of the project is expected to be completed in 2019. Upon completion, the new pipeline system would provide up to 640 MMcf/d of natural gas transportation capacity, with up to 570 MMcf/d delivered to Mexican markets.

VIKING GAS TRANSMISSION – INCREASED RATES AND FLEXIBILITY

In 2014, our FERC-regulated Viking Gas Transmission interstate natural gas pipeline, which serves local natural gas distribution companies in Minnesota, North Dakota and Wisconsin, sought to increase its transportation rates. The uncontested settlement increased rates to offset contract realignments. These new rates took effect January 1, 2015.

The settlement also included approximately $18 million in capital expenditures on various projects, including a project completed in November 2014 that positioned Viking as a bi-directional pipeline. This added flexibility positions Viking to address its customers' needs and capture future growth opportunities, making ONEOK Partners more competitive in the marketplace.

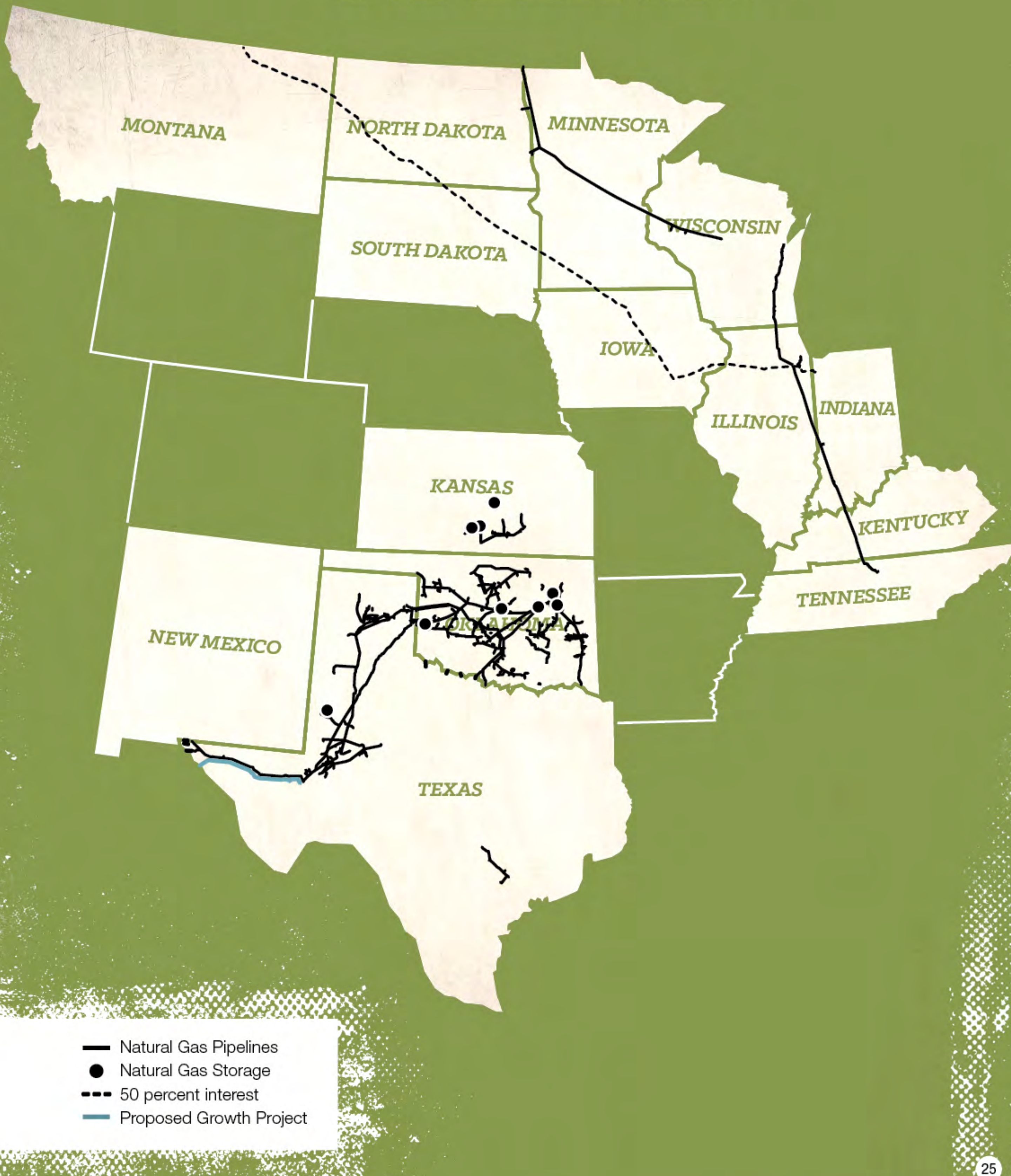
ONGOING FOCUS ON SAFETY

As part of our ongoing commitment to pursue a zero-incident culture, the company, led by the natural gas pipelines segment, participated in the Interstate Natural Gas Association of America (INGAA) Safety Culture Survey in 2014. Designed to gain insight into the energy industry's safety culture, the survey measured employee attitudes and opinions at ONEOK Partners and 17 of our peer companies.

Our natural gas pipelines segment had a 94 percent participation rate and received an overall safety index score of 74 percent, which compares favorably with the INGAA industry average safety index score of 73 percent. The results reflect positively on our applied-knowledge philosophy of continually looking for ways to improve our safety performance.

An employee uses a natural gas detector at our natural gas storage facility near Edmond, Oklahoma.

NATURAL GAS PIPELINES



GROWTH PROJECTS: COMPLETED

From 2010 through 2014, we invested approximately $6 billion for natural gas and natural gas liquids (NGL) capital-growth projects and acquisitions to enhance our midstream capabilities and enable us to better serve customers.

NATURAL GAS GATHERING AND PROCESSING *(Approximately $2.2 billion)*

COMPLETED PROJECT	LOCATION	SIZE	APPROX. COST	COMPLETED
ROCKY MOUNTAIN REGION				
Garden Creek I plant and infrastructure	Williston Basin	100 MMcf/d	$360 million	Dec. 2011
Stateline I and II plants and infrastructure	Williston Basin	200 MMcf/d	$565 million	Sept. 2012/ April 2013
Divide County gathering system	Williston Basin	270 miles	$125 million	June 2013
Sage Creek plant and infrastructure*	Powder River Basin	50 MMcf/d	$152 million	Sept. 2013
Garden Creek II plant and infrastructure	Williston Basin	100 MMcf/d	$300-$310 million	Aug. 2014
Garden Creek III plant and infrastructure	Williston Basin	100 MMcf/d	$300-$310 million	Oct. 2014
MID-CONTINENT REGION				
30 percent interest in Maysville plant*	Cana-Woodford Shale	40 MMcf/d	$90 million	Dec. 2013
Canadian Valley plant and infrastructure	Cana-Woodford Shale	200 MMcf/d	$255 million	March 2014

NATURAL GAS LIQUIDS *(Approximately $3.8 billion)*

COMPLETED PROJECT	LOCATION	SIZE	APPROX. COST	COMPLETED
Sterling I Pipeline expansion	Mid-Continent	15,000 bpd	$36 million	Nov. 2011
Cana-Woodford/Granite Wash NGL plant connections	Mid-Continent	77,000 bpd	$220 million	April 2012
Bushton NGL fractionator expansion	Mid-Continent	60,000 bpd	$117 million	Sept. 2012
Bakken NGL Pipeline	Rocky Mountain Region	60,000 bpd	$455 million	April 2013
Overland Pass Pipeline expansion	Mid-Continent	60,000 bpd	$36 million	April 2013
Ethane Header pipeline	Texas Gulf Coast	400,000 bpd	$23 million	April 2013
Sage Creek plant NGL infrastructure*	Powder River Basin	Various	$153 million	Sept. 2013
MB-2 NGL fractionator	Texas Gulf Coast	75,000 bpd	$375 million	Dec. 2013
Ethane/Propane splitter	Texas Gulf Coast	40,000 bpd	$46 million	March 2014
Sterling III Pipeline and reconfigure Sterling I and II	Mid-Continent	193,000 bpd	$808 million	March 2014
Bakken NGL Pipeline expansion – Phase I	Rocky Mountain Region	75,000 bpd	$75-$90 million	Sept. 2014
Niobrara NGL Lateral	Powder River Basin	90 miles	$70-$75 million	Sept. 2014
West Texas LPG pipeline system*	Permian Basin	2,600 miles	$800 million	Nov. 2014
MB-3 NGL fractionator	Texas Gulf Coast	75,000 bpd	$520-$540 million	Dec. 2014

*Acquisition

GROWTH PROJECTS: ANNOUNCED

We have announced investments of approximately $3 billion for natural gas and NGL capital-growth projects that will enhance our midstream capabilities and enable us to better serve customers.

NATURAL GAS GATHERING AND PROCESSING *(Approximately $1.8 billion to $2.6 billion)*

PROJECT IN PROGRESS	LOCATION	SIZE	APPROX. COST	EXPECTED COMPLETION DATE
ROCKY MOUNTAIN REGION				
Sage Creek plant infrastructure	Powder River Basin	Various	$50 million	Fourth Quarter 2015
Natural gas compression	Williston Basin	100 MMcf/d	$80-$100 million	Fourth Quarter 2015
Lonesome Creek plant and infrastructure	Williston Basin	200 MMcf/d	$550-$680 million	Fourth Quarter 2015
Stateline De-ethanizers	Williston Basin	26,000 bpd	$60-$80 million	Fourth Quarter 2015
Bear Creek plant and infrastructure	Williston Basin	80 MMcf/d	$230-$330 million	Third Quarter 2016
Bronco plant and infrastructure	Powder River Basin	50 MMcf/d	$130-$200 million	Suspended
Demicks Lake plant and infrastructure	Williston Basin	200 MMcf/d	$475-$670 million	Suspended
MID-CONTINENT REGION				
Knox plant and infrastructure	SCOOP	200 MMcf/d	$240-$470 million	Suspended

NATURAL GAS LIQUIDS *(Approximately $300 million to $345 million)*

PROJECT IN PROGRESS	LOCATION	SIZE	APPROX. COST	EXPECTED COMPLETION DATE
NGL pipeline and Hutchinson fractionator infrastructure upgrades	Mid-Continent	95 miles	$110-$125 million	First Quarter 2015
Bakken NGL Pipeline expansion – Phase II	Rocky Mountain Region	25,000 bpd	$100 million	Second Quarter 2016
Bear Creek NGL infrastructure	Williston Basin	40 miles	$35-$45 million	Third Quarter 2016
Bronco NGL infrastructure	Powder River Basin	65 miles	$45-$60 million	Suspended
Demicks Lake NGL infrastructure	Williston Basin	12 miles	$10-$15 million	Suspended

FINANCIAL SUMMARY

Through 2014, we've increased our distributions declared to unitholders by 98 percent since April 2006, when a wholly owned subsidiary of ONEOK became the sole general partner.

Overall, 2014 distributions declared increased more than 6 percent, compared with 2013. Completed capital-growth projects allowed us to increase cash distributions to our unitholders by 1.5 cents per unit each quarter of 2014. Due to an uncertain and lower commodity price environment, we have revised our 2015 expected distribution growth rate to 3 to 5 percent compared with 2014, subject to board approval.

In 2014, we completed approximately $2.4 billion of capital-growth projects and an $800 million acquisition of the West Texas natural gas liquids pipeline system. To finance our capital-growth projects, we will use a combination of debt and equity.

We remain committed to managing our balance sheet and maintaining investment-grade credit ratings. At year-end 2014, our total debt-to-capitalization ratio was 54 percent. Our long-term target is a capital structure of 50 percent debt and 50 percent equity.

We completed the following equity issuances in 2014:

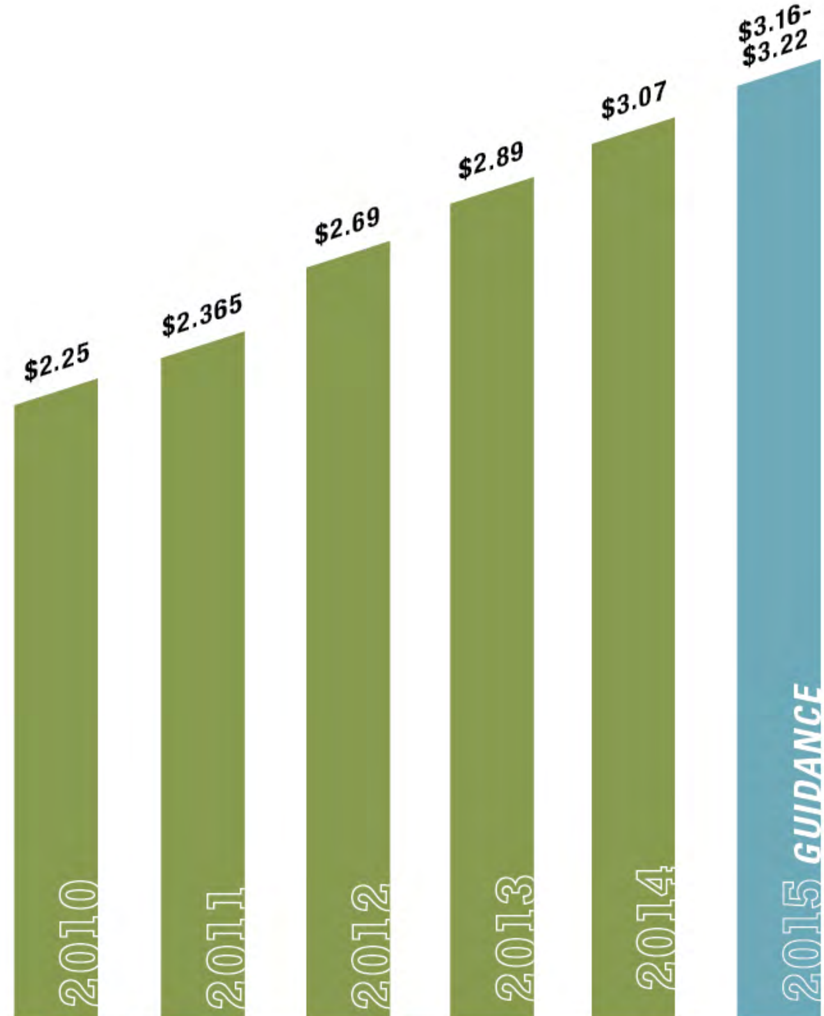
» A public equity offering in May, issuing approximately 13.9 million common units, generating net proceeds of approximately $730 million; and

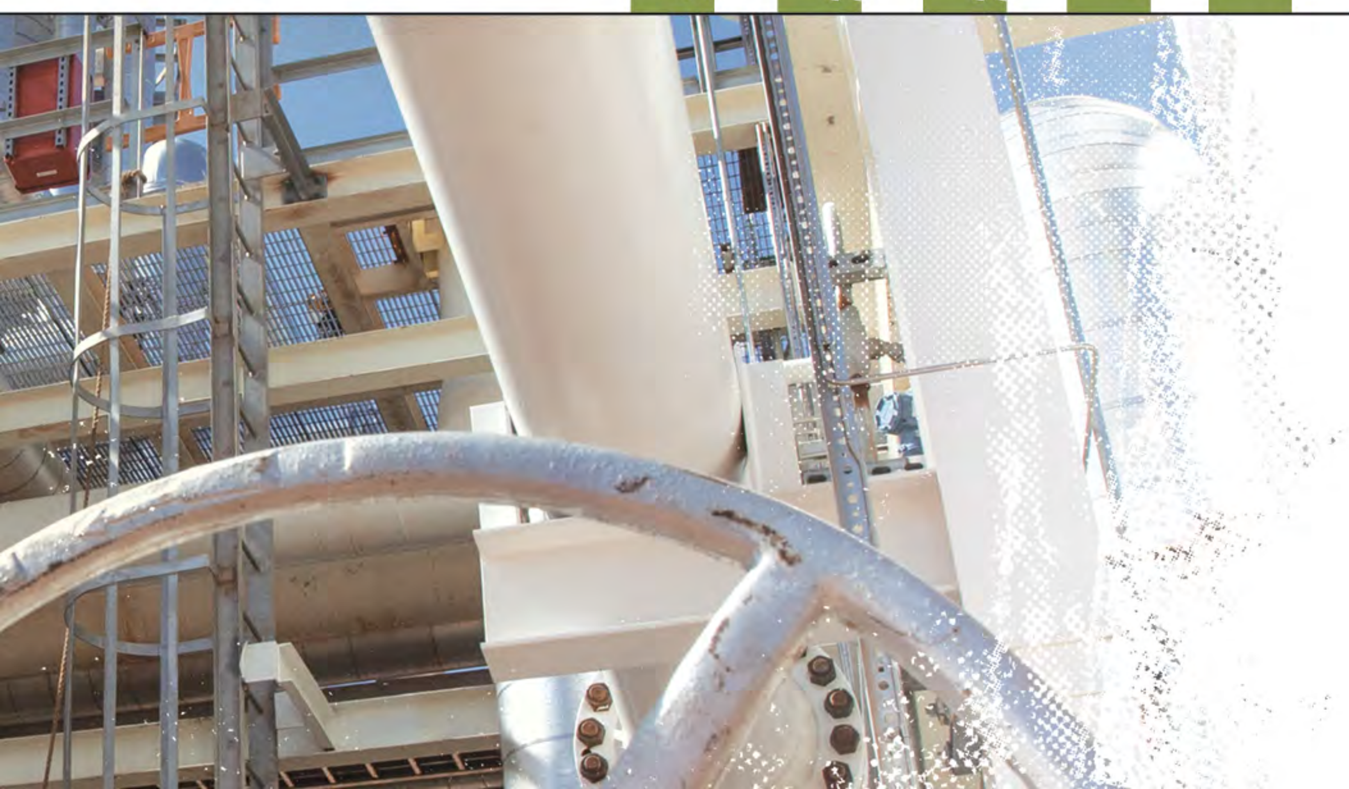
» Equity issuances throughout 2014 generating net proceeds of approximately $402 million through our at-the-market equity program.

As a result of these equity issuances, ONEOK's aggregate ownership interest in ONEOK Partners decreased to 37.8 percent as of December 31, 2014, from 41.2 percent as of December 31, 2013.

DISTRIBUTION GROWTH

ONEOK Partners annual distributions declared per unit (split adjusted)





CORPORATE RESPONSIBILITY

Our commitment to being a responsible corporate citizen continues to be a key focus in everything we do. We know that operating responsibly and improving the communities where our employees live and work will help ONEOK Partners remain a sustainable company for years to come.

STAYING FOCUSED ON ENVIRONMENT, SAFETY AND HEALTH

During the last several years, as we have grown our business and expanded our operational footprint, we also have strengthened our commitment to improve our companywide environmental, safety and health (ESH) performance.

We continue to keep our focus in the right place – on our stakeholders and on our mission to operate reliably, safely and environmentally responsibly.

In 2014, our Environment, Safety and Health Leadership Committee, composed of senior management representatives tasked with providing direction and support of ESH initiatives across the company, focused on these five initiatives:

» Culture enhancement;

» Peer feedback;

» Regulatory updates;

» Stakeholder outreach; and

» The development of tools needed to accomplish these initiatives.

While many of these initiatives are not new, we are committed to improving in all of these areas. An update on the progress of these initiatives will be included in the 2014 Corporate Responsibility Report, which will be published later this year.

INVESTING IN OUR COMMUNITIES

We are committed to being active members of the communities where we operate. Investing in the areas where we have operations and where our employees live and work is not only the right thing to do – it's smart business. By contributing financially and through volunteer work, we can help build stronger communities and create a better environment for our employees, customers and the general public.

We accomplish this in a number of ways, including grants from the ONEOK Foundation, corporate contributions to nonprofit organizations and employee volunteer efforts. Our community investments in 2014 included:

» $2.8 million in contributions from the ONEOK Foundation;

» $2.7 million from corporate contributions to support local nonprofit organizations; and

» 2,900 volunteer hours from employees, worth a value of more than $65,000 (based on the current volunteer-hour value of $22.55).

For more detailed information about our corporate responsibility efforts – including ESH and community investments – look for our 2014 Corporate Responsibility Report, which will be available on www.oneokpartners.com later this year.

An employee performs a safety inspection at our natural gas storage facility near Edmond, Oklahoma.

BOARD OF DIRECTORS

JULIE H. EDWARDS
Former Chief Financial Officer, Southern Union Company; Former Chief Financial Officer, Frontier Oil Corporation
Houston, Texas

JIM W. MOGG
Retired Chairman, DCP Midstream GP, L.L.C.
Hydro, Oklahoma

JOHN W. GIBSON
Chairman of the Board, and Retired Chief Executive Officer, ONEOK Partners, L.P. and ONEOK, Inc.
Tulsa, Oklahoma

GARY N. PETERSEN
Former President and Chief Operating Officer, Reliant Energy-Minnegasco; Retired President, Endres Processing LLC
Minneapolis, Minnesota

CRAIG F. STREHL
Retired Executive, Southern Union Company
Fort Worth, Texas

STEVEN J. MALCOLM
Retired Chairman, President and Chief Executive Officer, The Williams Companies, Inc.
Tulsa, Oklahoma

TERRY K. SPENCER
President and Chief Executive Officer, ONEOK Partners, L.P. and ONEOK, Inc.
Tulsa, Oklahoma

GIL J. VAN LUNSEN
Retired Managing Partner, KPMG LLP
Durango, Colorado

OFFICERS

POSITIONS AS OF MARCH 1, 2015 • AGES AS OF DECEMBER 31, 2014

ONEOK PARTNERS

TERRY K. SPENCER, 55
President and Chief Executive Officer

ROBERT F. MARTINOVICH, 57
Executive Vice President and Chief Administrative Officer

WALTER S. HULSE III, 50
Executive Vice President, Strategic Planning and Corporate Affairs

WESLEY J. CHRISTENSEN, 61
Senior Vice President, Operations

STEPHEN W. LAKE, 51
Senior Vice President, General Counsel and Assistant Secretary

DEREK S. REINERS, 43
Senior Vice President, Chief Financial Officer and Treasurer

ROBERT S. MAREBURGER, 53
Senior Vice President, Market Analysis

CHARLES M. KELLEY, 56
Senior Vice President, Corporate Planning and Development

SHERIDAN C. SWORDS, 45
Senior Vice President, Natural Gas Liquids

KEVIN L. BURDICK, 50
Vice President, Natural Gas Gathering and Processing

J. PHILLIP MAY, 52
Vice President, Natural Gas Pipelines

SHEPPARD F. MIERS III, 46
Vice President, Chief Accounting Officer

ERIC GRIMSHAW, 62
Vice President, Associate General Counsel and Corporate Secretary

ONEOK, INC.

TERRY K. SPENCER, 55
President and Chief Executive Officer

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Executive Vice President and Chief Administrative Officer

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Vice President, Chief Accounting Officer

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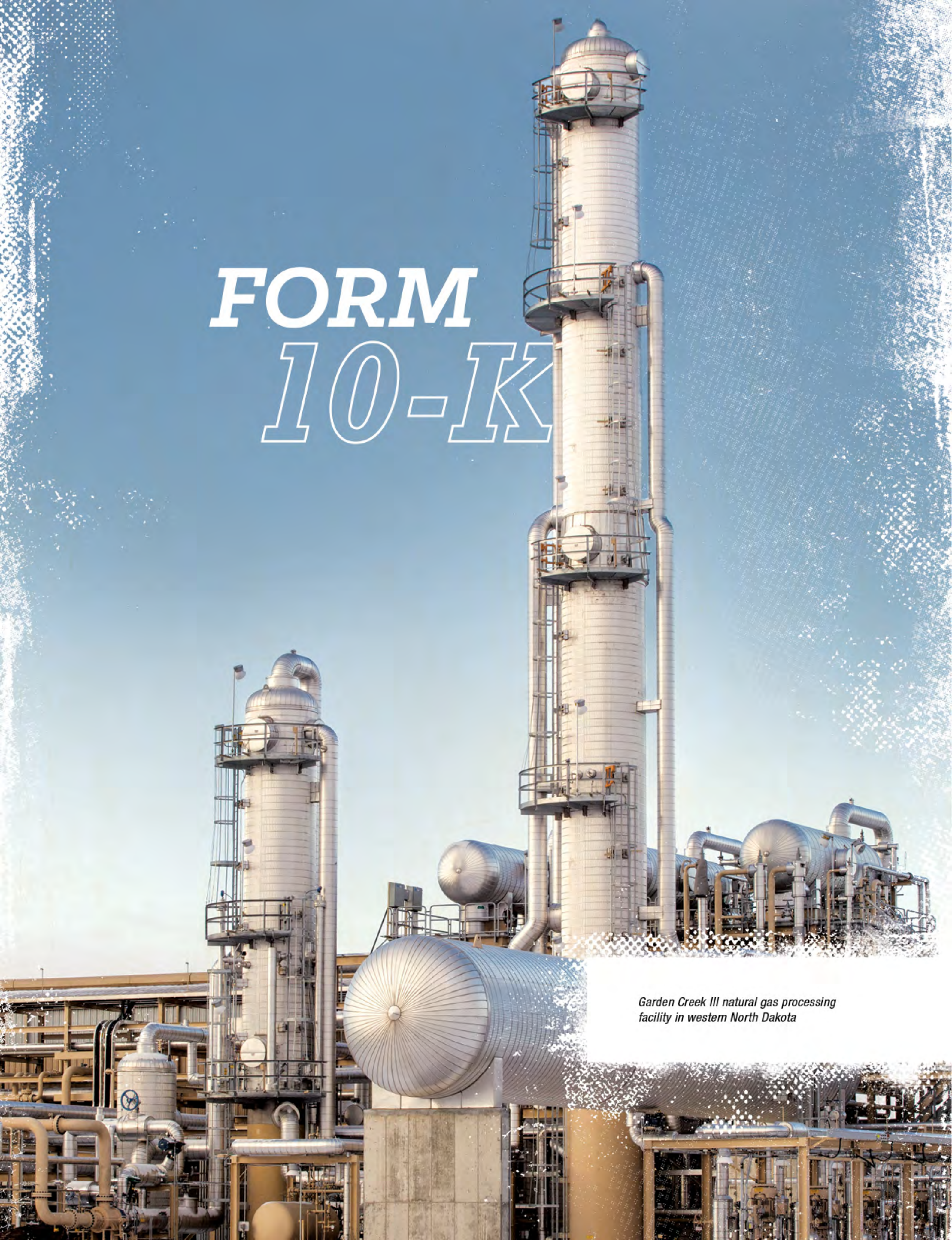
Vice President, Associate General Counsel and Corporate Secretary

FORM 10-K



Garden Creek III natural gas processing facility in western North Dakota

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, 2014.
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, 2014, was $9.1 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 17, 2015
Common units	180,826,973 units
Class B units	72,988,252 units

DOCUMENTS INCORPORATED BY REFERENCE: None.

ONEOK PARTNERS, L.P.
2014 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, 2014
ASU	Accounting Standards Update
Bbl	Barrels, 1 barrel is equivalent to 42 United States gallons
Bbl/d	Barrels per day
BBtu/d	Billion British thermal units per day
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
CFTC	Commodities 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
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
MMBtu/d	Million British thermal units per day
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 products	Marketable natural gas liquid purity products, such as ethane, ethane/propane mix, propane, iso-butane, normal butane and natural gasoline
NGL(s)	Natural gas liquid(s)
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 $1.7 billion Amended and Restated Revolving Credit Agreement effective as of January 31, 2014
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
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
TransCanada	TransCanada Corporation
WTI	West Texas Intermediate
West Texas LPG	The West Texas LPG Pipeline Limited Partnership and the Mesquite Pipeline
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 - The global demand for crude oil has continued to increase, but significantly higher supply has led to a dramatic fall in crude oil prices. Commodity prices declined sharply in the fourth quarter 2014 and continued to decline into early 2015. WTI crude oil prices declined to less than $50.00 per barrel in early 2015, compared with approximately $90.00 per barrel in September 2014. NYMEX natural gas prices also declined to approximately $3.00 per MMBtu in early 2015, compared with prices in excess of $4.00 per MMBtu in September 2014. The decline in crude oil prices has also contributed to lower NGL product prices and narrow NGL product price differentials.

We expect lower commodity prices to persist throughout 2015. In response, producer capital investment for crude oil and natural gas exploration and development is expected to decrease, and declines in crude oil and natural gas production and reduced drilling activity are expected to slow crude oil, natural gas and NGL supply growth. We expect crude oil and natural gas producers to focus capital spending and drilling activities on core locations that are most economical to develop.

We also expect narrow NGL price differentials with periods of volatility for certain NGL products between the Conway, Kansas, and Mont Belvieu, Texas, market centers to persist as new fractionators and pipelines from the various NGL-rich shale areas throughout the country, including our growth projects discussed below, continue to add supply to the market.

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

The lower commodity price environment is expected to have an adverse impact on our financial results in 2015. We are responding by aligning our operating costs and capital-growth projects with the needs of crude oil and natural gas producers, which includes suspending, reducing or eliminating certain capital-growth projects; limiting increases of distributions to our limited partners and negotiating various contract enhancements.

Supply - Because crude oil and natural gas producers received higher market prices on a heating-value basis for crude oil and NGLs compared with natural gas, many producers in North America focused their drilling activity in NGL-rich shale areas throughout the country that produce crude oil and NGL-rich natural gas rather than areas that produce dry natural gas. Domestic supplies of natural gas, natural gas liquids and crude oil continued to increase primarily as a result of increased production from horizontal drilling and hydraulic fracturing in these nonconventional shale resource areas. This resulted in crude oil, natural gas and NGL production increasing at a rate faster than demand.

The recent decline in crude oil, natural gas and NGL prices, along with announced reductions in producer drilling activities, are expected to slow supply growth in the United States in 2015. However, we continue to expect demand for midstream infrastructure development to be driven by producers who need to connect production with end-use markets where current infrastructure is insufficient or nonexistent.

The significant drilling activity 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 our natural gas gathered and processed volumes in the Williston Basin to continue to grow in 2015, despite expected reductions in producer drilling activity. We expect to capture a substantial amount of natural gas currently being flared by producers and production from wells that have been drilled but not yet completed or connected to our system. We expect additional volume from new wells focused in core areas, which typically produce at higher initial production rates compared with noncore areas. We also expect supply growth to continue in 2016 and 2017, although not as rapidly as growth experienced in 2014.

Due to success in extracting NGLs, ethane production has increased more rapidly than the petrochemical industry's current demand for ethane. We believe similar market conditions may generally persist until ethylene producers increase their capacity, with the largest number of additions expected to be completed over the next two to four years, to consume additional ethane feedstock volumes through plant modifications and expansions, and the completion of announced new world-scale ethylene production capacity. As a result, natural gas processors continue to limit the recovery of the ethane component of the natural gas stream, also known as ethane rejection. Instead, natural gas processors leave much of the ethane component in the natural gas stream sold at the tailgate of natural gas processing plants. Low or unprofitable price differentials between ethane and natural gas resulted in ethane rejection at most of our natural gas processing plants and most of our customers' natural gas processing plants connected to our natural gas liquids gathering system in the Mid-Continent and Rocky Mountain regions during 2013 and 2014, which reduced natural gas liquids volumes gathered, fractionated and transported in our Natural Gas Liquids segment and our results of operations.

We expect ethane rejection to persist until new world-scale ethylene production capacity, which is anticipated to begin coming on line in 2017, significantly increases ethane demand. Ethane rejection is expected to continue to have a significant impact on our financial results through 2017. However, our Natural Gas Liquids segment's integrated assets enable it to mitigate partially the impact of ethane rejection through minimum volume commitments and our ability to utilize the transportation capacity made available due to ethane rejection to capture additional NGL location price differentials in our optimization activities. See additional discussion in the "Financial Results and Operating Information" section.

Growth Projects - In response to increased production of crude oil, natural gas and NGLs, and higher demand for NGL products, we completed approximately $5.9 billion in growth projects and acquisitions from 2010 through 2014 and have approximately $2.1 billion to $3.0 billion of projects in various stages of construction, including approximately $2.2 billion in new projects and acquisitions announced in 2014, to meet the needs of natural gas producers and processors, as well as enhance our natural gas liquids fractionation, distribution and storage infrastructure in the Gulf Coast region. This infrastructure also will enhance the distribution of NGL products to meet the increasing petrochemical industry and NGL export demand. We are responding to changes in producer drilling activity by suspending capital expenditures for several projects. We expect to resume our suspended capital-growth projects as soon as market conditions improve. When completed, we expect these projects to increase volumes in our businesses and generate additional earnings and cash flows, particularly from fee-based revenues in our Natural Gas Liquids segment, while also increasing commodity price sensitivity in our Natural Gas Gathering and Processing segment. If the current commodity price environment persists for a prolonged period, it may further impact the timing or demand for existing and additional infrastructure projects or growth opportunities in the future.

Liquidity - Our structure as a master limited partnership requires us to pay out all of our available cash in distributions to our unitholders. During 2014, we paid cash distributions of $3.01 per unit, an increase of approximately 5 percent compared with the $2.87 per unit paid during 2013. In January 2015, our general partner declared a cash distribution of $0.79 per unit ($3.16 per unit on an annualized basis) for the fourth quarter 2014, an increase of approximately 8 percent compared with the $0.73 declared in January 2014.

In December 2013, we amended and restated our credit agreement, effective January 31, 2014, to increase the capacity of the facility to $1.7 billion from $1.2 billion and extended the maturity to January 2019. In February 2015, we notified our lenders of our intent to exercise our option to increase the capacity of the facility to $2.4 billion by increased commitments from existing lenders and/or commitments from one or more new lenders, which is pending lenders' approval. The facility is available to provide liquidity for working capital, capital expenditures and other general partnership purposes.

In 2014, we issued approximately 21.8 million common units through an underwritten public offering and our "at-the-market" equity program, generating net proceeds of approximately $1.1 billion, including ONEOK Partners GP's contribution to maintain its 2 percent general partner interest in us. We utilized proceeds from these equity issuances, cash from operations and short-term borrowings under our commercial paper program to meet our short-term liquidity needs, repay amounts outstanding under our commercial paper program, fund our capital projects and acquisitions and for general partnership purposes.

We rely heavily on capital markets to finance our capital-growth projects. 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. We expect to fund our future capital expenditures with short- and long-term debt, the issuance of equity and operating cash flows. The recent decline in commodity prices has contributed to a decrease in our unit price. While lower commodity prices and industry uncertainty may increase debt and equity financing costs, we expect to have sufficient liquidity to finance our announced capital-growth projects.

See Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation, for 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 continue to increase natural gas volumes gathered and processed in our Natural Gas Gathering and Processing segment, which generates earnings from primarily POP and contracts with a fee-based component; and NGL volumes gathered and fractionated in our Natural Gas Liquids segment, which generates earnings from primarily fee-based contracts, as producers continue to develop NGL-rich resource areas that we serve in the Mid-Continent and Rocky Mountain areas. We also generate stable earnings from our Natural Gas Pipelines segment, which provides primarily fee-based natural gas transportation and storage services primarily to natural gas and electric utilities. In 2014, we announced new capital projects and acquisitions of $2.2 billion, increasing our total growth program, which began in 2010, to approximately $8.0 billion to $8.9 billion. These projects are expected to meet the needs of NGL and natural gas producers in the Williston Basin and NGL-rich areas of the Powder River Basin in the Rocky Mountain region; the Cana-Woodford Shale, Woodford Shale, Springer Shale, Stack and SCOOP areas in Oklahoma; and the Permian Basin in Texas and New Mexico; and provide additional natural gas liquids infrastructure in the Mid-Continent and Gulf Coast areas, which will enhance the distribution of NGL products to meet the increasing petrochemical industry and NGL export demand. When completed, these capital projects are anticipated to provide additional earnings and cash flows. Also, in November 2014, we acquired the West Texas LPG system for approximately $800 million. This system 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 West Texas LPG system is expected to provide us additional fee-based earnings and provide our natural gas liquids infrastructure with access to a new natural gas liquids supply basin;
- <u>Manage our balance sheet and maintain investment-grade credit ratings</u> - even under challenging market conditions, our balance sheet remains strong. We ended 2014 with approximately $630.7 million of credit available under the Partnership Credit Agreement. We will 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.

<u>Natural Gas Gathering and Processing</u>

Overview - Our Natural Gas Gathering and Processing segment provides nondiscretionary services to producers that include gathering and processing of natural gas produced from crude oil and natural gas wells. Unprocessed natural gas is compressed and gathered through pipelines and transported to processing facilities where volumes are aggregated, treated and processed to remove water vapor, solids and other contaminants and to extract NGLs in order to provide marketable natural gas, commonly referred to as residue gas. The residue gas, which consists primarily of methane, is compressed and delivered to natural gas pipelines for transportation to end users. When the NGLs are separated from the unprocessed natural gas at the processing plants, the NGLs are in the form of a mixed, unfractionated NGL stream that is delivered to natural gas liquids gathering pipelines for transportation to natural gas liquids fractionators.

We gather and process natural gas in the Mid-Continent region, which includes the NGL-rich Cana-Woodford Shale, Woodford Shale, Stack, SCOOP, Springer Shale and 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. Coal-bed methane, or dry natural gas, in the Powder River Basin does not require processing or NGL extraction in order to be marketable; dry natural gas is gathered, compressed and delivered into a downstream pipeline or marketed for a fee.

The significant growth in the development of crude oil and NGL-rich natural gas 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. In July 2014, the North Dakota Industrial Commission approved a policy designed to limit 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 are constructing additional natural gas gathering pipelines, compression and 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 2015, 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 core areas, which typically produce at higher initial production rates compared with noncore areas.

Revenues for this segment are derived primarily from commodity and fee-based contracts. We generally gather and process natural gas under the following types of contracts:

- POP with fee - We retain a percentage of the proceeds from the sale of residue gas, condensate and/or NGLs, and charge fees for gathering, treating, compressing and/or processing the producer’s natural gas. POP with fee contracts expose us to commodity price risk. This type of contract represented approximately 87 percent and 85 percent of contracted volumes in this segment for 2014 and 2013, respectively. There are a variety of factors that directly affect our POP revenues, including:
  - the natural gas, crude oil and NGL prices received for our retained products;
  - the percentage of NGL, condensate and residue natural gas sales proceeds retained by us that we receive as payment for the services we provide;
  - the composition of the NGLs produced;
  - volume produced that affects our fee revenue; and
  - transportation and fractionation costs incurred on the NGLs, condensate and natural gas we retain.
- Fee - We are paid a fee for the services we provide, based on volumes gathered, processed, treated and/or compressed. Our fee-based contracts represented approximately 13 percent and 15 percent of contracted volumes in this segment for 2014 and 2013, respectively.

We expect our capital projects will continue to generate additional revenues, earnings and cash flows as they are completed. Our natural gas liquids and natural gas commodity price sensitivity within this segment may increase in the future as our capital projects are completed and volumes increase under POP contracts with a fee-based component with our customers. 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. We continue to seek opportunities to convert our POP contracts to fee-based contracts or increase the fee component in our POP contracts.

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

- 49 percent ownership interest in Bighorn Gas Gathering, which operates a major coal-bed methane gas gathering system serving a broad production area in northeast Wyoming;
- 37 percent ownership interest in Fort Union Gas Gathering, which gathers coal-bed methane gas produced in the Powder River Basin and delivers it into the interstate pipeline grid;
- 35 percent ownership interest in Lost Creek Gathering Company, which gathers natural gas produced from conventional wells in the Wind River Basin of central Wyoming and delivers natural gas into the interstate pipeline grid; and
- 10 percent ownership interest in Venice Energy Services Co., a natural gas processing complex 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 - Natural gas supply is affected by producer drilling activity, which is sensitive to commodity prices, drilling rig availability, exploration success, operating capability, access to capital and regulatory control. In recent years, higher crude oil prices and advances in horizontal drilling and completion technology have had a positive impact on drilling activity, which has provided an offset to the less favorable supply projections in some of the conventional resource areas. However, the recent decrease in crude oil prices has resulted in a decline in drilling activity in the shale formations, and further reductions are expected in 2015.

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. This is more prevalent in the Rocky Mountain region where temperatures tend to be colder than in the Mid-Continent region but can occur throughout our systems. All of our operations may be affected by other weather conditions that may cause a loss of electricity or prevent access to certain locations that affect a producer's ability to complete wells or our ability to connect these wells to our systems.

In the Rocky Mountain region, Williston Basin natural gas volumes continued to grow in 2014 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 2015, compared with 2014, due to lower commodity prices and reduced drilling activity. We do not expect the decrease in drilling activities to impact materially our volume growth in 2015 due to the significant amount of natural gas currently being flared by producers and new production requiring connection to our gathering and processing system. If current crude oil prices persist beyond 2015, volume growth in this region could slow further or possibly decline. We expect slower volume growth in the NGL-rich Niobrara Shale area of the Powder River Basin in the current commodity price environment. Additionally, we have seen declines in natural gas volumes gathered in portions of the Powder River Basin that produce dry gas from coal-bed methane areas. We expect the energy commodity price environment to remain depressed for at least the near term, which has caused producers to announce plans for reduced drilling for crude oil and natural gas, which we expect will slow volume growth or reduce volumes of natural gas and NGLs delivered to systems owned by our equity method investments. If the current energy commodity price environment persists for a prolonged period or further declines, it could result in additional impairments of our equity method investments.

In the Mid-Continent region, we have significant natural gas gathering and processing assets in Oklahoma and Kansas. During 2015, we expect drilling activity in the Cana-Woodford Shale, Woodford Shale, Stack and SCOOP areas in Oklahoma to offset partially the volumetric declines from existing wells that supply our natural gas gathering and processing facilities. If the current energy commodity price environment persists for a prolonged period or declines further, our natural gas gathered and processed volumes for this region may further decline.

Demand - Demand for natural gas gathering and processing services is aligned typically with the production of natural gas from natural gas resource areas or the associated natural gas from wells drilled in crude oil resource areas. Gathering and processing are nondiscretionary services that producers require to market their natural gas and NGL production. Due to the recent decline in crude oil prices, we expect producer capital investment to decrease, which combined with decline rates and lower drilling activity is expected to slow crude oil, natural gas and NGL supply growth. This may result in decreased demand for our gathering and processing services if there is not sufficient natural gas production from new drilling activity to offset the natural decline in production volumes.

Commodity Prices - Crude oil, natural gas and NGL prices historically have been volatile and may be subject to significant fluctuations in the future as market conditions change. For example, WTI crude oil prices declined to less than $50.00 per barrel in early 2015, compared with approximately $90.00 per barrel in September 2014. NYMEX natural gas prices also declined to approximately $3.00 per MMBtu in early 2015, compared with prices in excess of $4.00 per MMBtu in September 2014. The decline in crude oil prices has also contributed to lower NGL product prices and narrow NGL product price differentials.

We are exposed to commodity price risk and the cost of NGL transportation to various market locations as a result of receiving commodities through our POP contracts in exchange for our services. We use commodity derivative financial instruments and physical-forward contracts to reduce the near-term impact of price fluctuations related to natural gas, NGLs and condensate.

The price differential between the typically higher valued NGL products and the value of natural gas, particularly the price differential between ethane and natural gas, may influence the volume of NGLs recovered from natural gas processing plants. When economic conditions warrant, natural gas processors may elect to reduce the recovery of the ethane component of the natural gas stream, also known as ethane rejection, and instead leave much of the ethane component in the natural gas stream sold at the tailgate of natural gas processing plants. Our natural gas processing plant operations can be adjusted to respond to market conditions, such as demand for ethane. By changing operating parameters at certain plants, we can reduce the amount of ethane recovered if the price differential is unfavorable.

Seasonality - Certain products of this segment are subject to weather-related seasonal demand. Cold temperatures typically increase demand for natural gas and propane, which are used to heat homes and businesses. Warm temperatures typically drive demand for natural gas used for natural gas-fired electric generation needed to meet the demand required to cool residential and commercial properties. Demand for butanes and natural gasoline, which are used primarily by the refining industry as blending stocks for motor fuel, also may be subject to some variability as automotive travel increases and seasonal gasoline formulation standards are implemented. During periods of peak demand for a certain commodity, prices for that product typically increase.

Competition - The natural gas gathering and processing business remains relatively fragmented despite significant consolidation in the industry. We compete for natural gas supplies with major integrated oil companies, independent exploration and production companies that have gathering and processing assets, pipeline companies and their affiliated marketing companies, national and local natural gas gatherers and processors, and marketers in the Mid-Continent and Rocky Mountain regions. The factors that typically affect our ability to compete for natural gas supplies 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 natural gas liquids 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 are evaluating opportunities to increase earnings and cash flows, and reduce risk by:

- investing capital to construct and expand our assets;
- improving natural gas processing efficiency;
- reducing operating costs;
- consolidating assets;
- decreasing commodity price exposure; and
- renegotiating low-margin contracts.

Government Regulation - The FERC traditionally has maintained that a natural gas processing plant is not a facility for the transportation or sale for resale 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 various 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.

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. 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 that connect with our natural gas liquids fractionation and pipeline assets. In April 2013, we began transporting unfractionated NGLs from natural gas processing plants in the Williston Basin on our Bakken NGL Pipeline. These unfractionated NGLs previously were transported by rail to our Mid-Continent natural gas liquids fractionation facilities. We continue to use our rail-terminal facilities in our NGL marketing activities. 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 the 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 and propane distributors. We also purchase NGLs and condensate from third parties, as well as from our Natural Gas Gathering and Processing segment.

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; and 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 revenue are categorized as exchange services, optimization and marketing, pipeline transportation, and isomerization and storage, which are defined as follows:

- Our exchange-services activities utilize our assets to gather, fractionate and/or treat unfractionated NGLs for a fee, 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 optimization and marketing activities utilize our assets, contract portfolio and market knowledge to capture location, product and seasonal price differentials. We 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 are also utilized to capture seasonal price variances. A growing portion of our marketing activities serves truck and rail markets.
- Our pipeline transportation 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 isomerization activities capture the price differential when normal butane is converted into the more valuable iso-butane at our isomerization unit in Conway, Kansas. Iso-butane is used in the refining industry to increase the octane of motor gasoline.
- Our storage activities consist primarily of fee-based NGL storage services at our Mid-Continent and Gulf Coast storage facilities.

Since late 2012, NGL location price differentials have generally remained narrow between the Mid-Continent and Gulf Coast market centers. We expect these narrow NGL price differentials, with periods of volatility for certain NGL products, to continue as new fractionators and pipelines, including our growth projects discussed below, have alleviated constraints between the Conway, Kansas, and Mont Belvieu, Texas, natural gas liquids market centers. 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 regions to the Mont Belvieu, Texas, 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. Our Natural Gas Liquids segment's capital-growth projects are supported by fee-based contractual commitments that we expect will fill much of our optimization capacity used historically to capture NGL location price differentials between the two market centers.

Market Conditions and Seasonality - Supply - Supply for our Natural Gas Liquids segment depends on the pace of crude oil and natural gas drilling activity by producers, the decline rate of existing production and the NGL content of the natural gas that is produced and processed. Throughout 2014, domestic supplies of natural gas, natural gas liquids and crude oil continued to increase from drilling activities focused in crude oil and NGL-rich resource areas. North American crude oil, natural gas and NGL production continued to increase at a faster rate than demand, primarily as a result of increased production from nonconventional resource areas such as shale areas. However, the recent decline in crude oil, natural gas and NGL prices along with announced reductions in producer drilling activities are expected to slow supply growth in the United States in 2015. We expect the overall supply of NGLs, as well as demand for our fee-based services, to continue to increase in early 2015 as existing drilling activities are completed. Many new natural gas processing plants are being constructed in North Dakota, Wyoming, Oklahoma, West Texas and New Mexico to process NGL-rich natural gas being produced in the Williston Basin, Bakken Shale, Niobrara Shale, Powder River Basin, Cana-Woodford Shale, Woodford Shale, SCOOP, Granite Wash, Permian Basin, Barnett Shale and Mississippian Lime areas. The unfractionated NGLs that we transport are gathered primarily from natural gas processing plants 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.

Our Natural Gas Liquids segment also is affected by operational or market-driven changes that affect the output of natural gas processing plants to which we are connected. The price differential between the typically higher valued NGL products and the value of natural gas, particularly the price differential between ethane and natural gas, has influenced the volume of ethane natural gas processing plants make available to be gathered in our Natural Gas Liquids segment. The recent economic conditions caused certain natural gas processors to reduce the recovery of the ethane component of the natural gas stream, also known as ethane rejection, and instead leave much of the ethane component in the natural gas stream sold at the tailgate of natural gas processing plants. Price differentials between ethane and natural gas resulted in ethane rejection at most of our natural gas processing plants and our customers' natural gas processing plants connected to our natural gas liquids gathering system in the Mid-Continent and Rocky Mountain regions during 2013 and 2014, which reduced natural gas liquids volumes gathered, fractionated and transported in our Natural Gas Liquids segment and our results of operations.

We expect ethane rejection to persist until new world-scale ethylene production capacity , which is anticipated to begin coming on line in 2017, significantly increases ethane demand. Ethane rejection is expected to continue to have a significant impact on our financial results through 2017. However, our Natural Gas Liquids segment's integrated assets enable it to mitigate partially the impact of ethane rejection through minimum volume commitments and our ability to utilize the transportation capacity made available due to ethane rejection to capture additional NGL location price differentials in our optimization activities. See additional discussion in the "Financial Results and Operating Information" section in our Natural Gas Liquids segment.

Natural gas, natural gas liquids and crude oil transportation constraints may also impact the output of natural gas processing plants in total or for specific NGL products. These constraints are currently being alleviated by the addition of new infrastructure and the projected slower growth in crude oil and natural gas production resulting from the recent decrease in prices.

Demand - 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 announced 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 in two to four years when the new petrochemical plants are expected to be completed. We do not expect the recent decline in crude oil, natural gas and natural gas liquids prices to impact the construction of new plants, plant expansions, additions or enhancements at petrochemical facilities in the Gulf Coast region. In addition, international demand for ethane, propane and butane is expected to continue affecting the NGL market in the future. We expect this increase in demand for NGLs will provide opportunities to increase fee-based earnings in our exchange services, storage and marketing activities.

Commodity Prices - In recent years, market conditions have occasionally produced periods of volatility, higher prices and wider NGL location and product price differentials. The abundance of NGLs produced from the development of shale and other resource areas has made NGL feedstocks to the petrochemical industry less costly. Ethane production has increased more rapidly than the petrochemical industry's current capability to consume the increase in supplies. This oversupply has contributed to low ethane prices since 2013. While petrochemical demand has remained strong since 2013, we expect the oversupply of ethane to persist until ethylene producers increase their capacity to consume additional ethane feedstock volumes through plant modifications and expansions, and the completion of announced new world-scale ethylene capacity is completed and ethane exports increase. In the near term, this ethane oversupply situation may result in low ethane prices and continued ethane rejection to balance supply and demand.

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 and optimization margins. When natural gas prices are higher relative to NGL prices, NGL production declines due to ethane rejection, which affects negatively our exchange services and transportation revenues. When the NGL location price differential between the Mid-Continent and Gulf Coast market centers is narrow, optimization opportunities and NGL shipments may decline, resulting in a decline in earnings from our NGL optimization and marketing activities. Since 2013, strong production and supply growth from the development of NGL-rich areas, increased demand in the Mid-Continent region 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.

We are also exposed to volumetric risk associated with producer drilling activity that is influenced by commodity prices. However, we are able to mitigate partially the impact of volume decreases through minimum volume commitments with customers.

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 is also affected by weather. In periods of cold weather, the processors ability to gather the raw gas is affected by freeze-offs or treating, limiting the amount of natural gas processed and thus NGL recovery. 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 are responding 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 Conway, Kansas, and Mont Belvieu, Texas, natural gas liquids market centers, we expect the narrow location price differentials between the Mid-Continent and Gulf Coast market centers to continue. In addition, new natural gas liquids pipeline projects are expected to bring incremental NGL supply from the Rocky Mountain, Marcellus and Utica basins to the Mont Belvieu, Texas, 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.

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 Kansas and Texas, certain aspects of our intrastate natural gas liquids pipelines that provide common carrier service are subject to the jurisdiction of the 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 owns and operates regulated natural gas transmission pipelines and natural gas storage facilities. We also provide interstate natural gas transportation and storage service in accordance with Section 311(a) of the Natural Gas Policy Act.

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 interstate pipeline companies include:

- Midwestern Gas Transmission, which is a bi-directional 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 bi-directional system, interconnects with a TransCanada 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 interconnects in Oklahoma, Texas and New Mexico.

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. 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; and transport natural gas throughout the western portion of Texas, including the Waha Hub where other pipelines may be accessed for transportation to western markets, the Houston Ship Channel market to the east and the Mid-Continent market to the north. We also have access to the major natural gas producing formations, including the Mississippian Lime formation in south central Kansas.

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.

Our transportation contracts for our regulated natural gas activities are based upon rates stated in our tariffs. Tariffs specify the maximum rates that customers may be charged, which may be discounted to meet competition if necessary, and the general terms and conditions for pipeline transportation service, which are established at FERC or appropriate state jurisdictional agency proceedings known as rate cases. In Texas and Kansas, natural gas storage service is a fee business that 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 also a fee business but are not subject to rate regulation by the state and have market-based rate authority from the FERC for certain types of services.

Our Natural Gas Pipelines segment's revenues are derived primarily from fee-based services. Revenues are generated from the following types of fee-based contracts:

- Firm service - Customers can reserve a fixed quantity of pipeline or storage capacity for the term of their contract. Under this type contract, the customer pays a fixed fee for a specified quantity regardless of their actual usage. The customer then typically pays incremental fees, known as commodity charges, that are based upon the actual volume of natural gas they transport or store, and/or we may retain a specified volume of natural gas in-kind for fuel. Under the firm-service contract, the customer generally is guaranteed access to the capacity they reserve; and
- Interruptible service - Customers with interruptible service transportation and storage agreements may utilize available capacity after firm-service requests are satisfied or on an as-available basis. Interruptible service customers typically

are assessed fees, such as a commodity charge, based on their actual usage, and/or we may retain a specified volume of natural gas in-kind for fuel. Under the interruptible service contract, the customer is not guaranteed use of our pipelines and storage facilities unless excess capacity is available.

Unconsolidated Affiliates - Our Natural Gas Pipelines segment includes our 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.

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

Market Conditions and Seasonality - Supply - 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. As new supply is developed, our customers may want access to this new shale supply, requiring new or additional services, to transport their production to the market. Our intrastate pipelines and storage assets could be impacted by the pace of natural gas drilling activity by producers and the decline rate of existing production in the major natural gas production areas in the Mid-Continent region.

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, which contains the Bakken Shale and Three Forks formations, 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 Northeast, may compete with and displace volumes from the Mid-Continent, Rocky Mountain and Canadian supply sources in our markets. Significant factors that can impact the supply of Canadian natural gas transported by our pipelines are the availability of United States supply, Canadian natural gas available for export, Canadian storage capacity and demand for Canadian natural gas in Canada and United States consumer markets.

Demand - Demand for natural gas pipeline transportation service and natural gas storage is related directly to our access to supply and the demand for natural gas in the markets that our natural gas pipelines and storage facilities serve. Demand is also affected by weather, the economy and natural gas price volatility. Our pipelines primarily serve end users, such as local natural gas distribution companies, electric-generation facilities, large industrial companies, municipalities and irrigation customers that 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." 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. Recent 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. The effect of weather on our natural gas pipelines operations is discussed below under "Seasonality." The strength of the economy directly impacts manufacturing and industrial companies that consume natural gas. Commodity price volatility can influence producers' decisions related to the production of natural gas and the level of NGLs processed from natural gas.

Commodity Prices - The high level of natural gas supply from the development of shale resource areas throughout the country has caused natural gas prices to remain low, and natural gas location and seasonal price differentials to generally narrow across the regions where we operate. 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 and analyze the market price differential between receipt and delivery points along the pipeline, also known as location differential, to determine their expected gross margin. The anticipated margin and its variability are important determinants of the transportation rate customers are willing to pay. 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. 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 natural 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 demand 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, contracted capacity declined in 2014 as a result of a contract which expired in the first quarter 2014. Due to the current storage capacity market, we have elected to use that capacity to provide park-and-loan services to our customers rather than recontracting it under long-term firm-service agreements. We also retain a small portion of our storage capacity for operational purposes.

Competition - Our natural gas pipelines and storage facilities compete directly with other intrastate and interstate pipeline companies and other storage facilities providing natural gas transportation and storage services. Our natural gas assets primarily serve local natural gas distribution companies, electric-generation facilities, large industrial companies, municipalities, irrigation customers and marketing companies. Competition among pipelines and natural gas storage facilities is based primarily on fees for services, quality of services provided, current and forward natural gas prices, and proximity to natural gas supply areas and markets. 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.

Government Regulation - 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 segment, 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.

Likewise, 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, but certain types of services may be regulated by the FERC.

Recent 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 the use of natural gas 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.

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 "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, and we do not expect the settlement to materially impact us.

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

Additional information about our environmental matters is included in Note O of the Notes to Consolidated Financial Statements in this Annual Report.

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, emission 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. On March 28, 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 business. 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.

The potential capital and operating expenditures related to this legislation, the associated regulations or other new pipeline safety regulations are unknown.

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 greenhouse gas (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 2013 total reported emissions were approximately 46.7 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 public comment period on the proposed rule-making remains pending and, as a result, the impact of any such proposed regulatory actions on our projects, facilities and operations is unknown.

The EPA's "Tailoring Rule" regulates GHG emissions at new or modified facilities that meet certain criteria. Affected facilities are required to review best available control technology (BACT), conduct air-quality, 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, on June 23, 2014, the Supreme Court of the United States, 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. However, the 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. We are in the process of evaluating the effects the decision and related pending judicial proceedings at the lower court level may have on our existing operations and the opportunities it creates for design decisions for new project applications.

In July 2011, the EPA issued a proposed rule that would change the air emission 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 EPA's final rule reflects significant changes from the proposal issued in 2011 and allows for more manageable compliance options. 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.

The rule was most recently amended in December 2014. The EPA has indicated that further amendments may be issued in 2015. Based on the amendments, our understanding of pending stakeholder responses to the NSPS rule and the proposed rule-making, we do not anticipate a material impact to our anticipated capital, operations and maintenance costs resulting from compliance with the regulation. However, the EPA may issue additional responses, amendments and/or policy guidance on the final rule, which could alter our present expectations. Generally, the NSPS rule will require expenditures for updated emissions controls, monitoring and record-keeping requirements at affected facilities in the crude oil and natural gas industry. 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 an interim rule in April 2007 that requires companies to provide reports on sites where certain chemicals, including many hydrocarbon products, are stored. We completed the Homeland Security assessments, 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 operates Guardian Pipeline, Viking Gas Transmission and Midwestern Gas Transmission according to each pipeline's operating agreement. ONEOK Partners GP may purchase services from ONEOK and its affiliates pursuant to the terms of the Services Agreement. As of January 31, 2015, we utilized some or all of the services of 2,269 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 Operation.

RISKS INHERENT IN OUR BUSINESS

Market volatility and capital availability could affect adversely our business.

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. Our ability to grow could be constrained if we do not have regular access to the capital and global credit markets. 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.

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 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 affect 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. NGL volumes could decline if it becomes uneconomical for natural gas processors to recover the ethane component of the natural gas stream as a separate product. In addition, crude oil, natural gas and NGL production could also decline due to lower prices.

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. Our ability to pay quarterly distributions depends primarily on cash flow, including cash flow from financial reserves and working capital borrowings, and not solely on profitability, which is affected by noncash items. As a result, we may pay cash distributions during periods when we record net losses and may be unable to pay cash distributions during periods when we record net income.

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 in exchange 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 NGL prices 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 fluctuations in natural gas, NGL and crude oil prices, we use derivative instruments such as swaps, futures and forwards. 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 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.

Our use of financial instruments to hedge interest-rate risk may result in reduced income.

We utilize financial instruments and physical-forward transactions to mitigate our exposure to interest-rate 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.

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.

Our inability to develop and execute growth projects and acquire new assets 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 and supply risks should adequate natural gas or NGL supply be unavailable upon completion of the facilities.

One of the ways we intend to grow our business 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 require significant capital expenditures, which may exceed our estimates, and involves numerous regulatory, environmental, political, legal and weather-related uncertainties. Construction projects in our industry may increase demand for labor, materials and rights of way, which may, in turn, affect our costs and schedule. If we undertake these projects, we may not be able to complete them on schedule or at the budgeted cost. Additionally, 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. Additionally, we may construct facilities to capture anticipated future growth in production in a region in which anticipated production growth does not materialize. We may also 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. 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 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 are subject to risks that could limit our access to capital, thereby increasing our costs and affecting adversely our results of operations.

Much of our business is capital intensive, and achievement of our long-term growth targets is dependent, at least in part, upon our ability to access capital at rates and on terms we determine to be attractive. We have grown rapidly in the past due in part to capital-growth projects and acquisitions. Future capital-growth projects and acquisitions may require additional capital. 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, will 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 our financial condition and future results of operations could be harmed significantly.

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.

Since the terrorist attacks on September 11, 2001, 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-integrity programs and repairs may impose significant costs and liabilities.

Pursuant to a DOT rule, pipeline operators are required to develop integrity-management programs for intrastate and interstate natural gas and natural gas liquids pipelines that could affect high-consequence areas in the event of a release of product. As defined by applicable regulations, high-consequence areas include areas near the route of a pipeline with high population densities, facilities occupied by persons of limited mobility and outdoor or indoor areas where at least 20 people periodically gather. The rule requires operators to identify pipeline segments that could impact a high-consequence area; improve data collection, integration and characterization of threats applicable to each segment and implement preventive and mitigating actions; perform ongoing assessments of pipeline integrity; and repair and remediate the pipeline as necessary. These testing programs could cause us to incur significant capital and operating expenditures to make repairs or remediate, as well as initiate preventive or mitigating actions that are determined to be necessary.

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 "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, tornadoes 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 nontraditional 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. 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, 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 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 the level of drilling and production in the Mid-Continent, Rocky Mountain, Texas and Gulf Coast regions declines substantially near our assets, our volumes and revenues could decline.

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, Texas and Gulf Coast regions. Drilling and production are impacted by factors beyond our control, including:

- demand and prices for natural gas, NGLs and crude oil;
- 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.

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.

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 $1.0 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 storage and 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 ratemaking 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 effect our business, financial position, results of operations and cash flows.

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.

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.

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 as we deem appropriate. If we fail to assess adequately the creditworthiness of existing or future customers or counterparties, unanticipated deterioration in their creditworthiness and any resulting nonpayment and/or nonperformance could adversely impact our results of operations. In addition, if any of our customers or counterparties file for bankruptcy protection, this could have a material negative impact on our business, financial condition, results of operations and cash flows.

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

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, 19.8 million common units and the entire 2 percent general partner interest in us, which together constituted a 37.8 percent ownership interest in us as of December 31, 2014. 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 37.8 percent aggregate equity interest in us at December 31, 2014. 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 Committee. 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" (Stable) and Prime-2, respectively, by Moody's and "BBB" (Stable) and A2, 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, 2014, we had total indebtedness of approximately $7.1 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 of the acquisition 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, which represent a return on investment, 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, it is possible, in certain circumstances, for a partnership such as ours to be treated as a corporation for federal income tax purposes. A change in our business or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity. If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35 percent, and would likely pay additional state income taxes at varying rates. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow through to our unitholders. Because a 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 are 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, members of the United States Congress may propose and consider substantive changes to the existing federal income tax laws that could affect the tax treatment of certain publicly traded partnerships. 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 be enacted ultimately. 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.

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.

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 purpose 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. The use of this proration method may not be permitted under existing Treasury regulations, and although the United States Department of the Treasury issued proposed Treasury regulations allowing a similar monthly simplifying convention, such regulations are not final and do not authorize specifically the use of the proration method we have adopted. If the IRS were to challenge our proration method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

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 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.

When we issue additional units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Moreover, under our current valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between the general partner and certain of our unitholders.

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 there is no tax concept of loaning a partnership interest, 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. In that case, 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 7,400 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 10 natural gas processing plants with approximately 665 MMcf/d of processing capacity in the Rocky Mountain region; and
- approximately 30 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 or plan to construct the following:

- four additional natural gas processing plants in the Rocky Mountain region, which will provide approximately 530 MMcf/d of combined processing capacity;
- projects to increase natural gas compression at existing facilities in the Rocky Mountain region, which will provide approximately 100 MMcf/d of processing capacity; and
- one natural gas processing plant in the Mid-Continent region, with approximately 200 MMcf/d of processing capacity.

Utilization - The utilization rates for our natural gas processing plants were approximately 84 percent and 71 percent for 2014 and 2013, 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 4,270 miles of FERC-regulated natural gas liquids gathering pipelines with peak capacity of approximately 633 MBbl/d;
- approximately 4,100 miles of FERC-regulated natural gas liquids and refined petroleum products distribution pipelines with peak capacity of 900 MBbl/d;

- one natural gas liquids fractionator, located in Oklahoma, with operating capacity of approximately 210 MBbl/d; two natural gas liquids fractionators, located in Kansas, with combined operating capacity of 280 MBbl/d; and two natural gas liquids fractionators, located 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 expect to place in service in the first quarter 2015 approximately 95 miles of FERC-regulated distribution pipelines from Hutchinson, Kansas, to Medford, Oklahoma.

We also have a 25 MBbl/d expansion of our Bakken NGL Pipeline and additional NGL infrastructure for our new natural gas processing plants in the Rocky Mountain region in various stages of construction.

Utilization - The utilization rates for our various assets, including leased assets, for 2014 and 2013, respectively, were as follows:

- our non-FERC-regulated natural gas liquids gathering pipelines were approximately 62 percent and 69 percent;
- our FERC-regulated natural gas liquids gathering pipelines were approximately 79 percent and 71 percent;
- our FERC-regulated natural gas liquids distribution pipelines were approximately 47 percent and 58 percent;
- our natural gas liquids fractionators were approximately 70 percent and 78 percent; and
- our average contracted natural gas liquids storage volumes were approximately 69 percent and 72 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 51.7 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.

Utilization - Our natural gas pipelines were approximately 91 percent subscribed in 2014 and 90 percent subscribed in 2013, and our natural gas storage facilities were 76 percent subscribed in 2014 and 92 percent subscribed in 2013.

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, 2014		Year Ended December 31, 2013	
	High	**Low**	**High**	**Low**
First Quarter	**$ 57.09**	**$ 50.10**	$ 60.59	$ 52.17
Second Quarter	**$ 58.60**	**$ 53.78**	$ 57.06	$ 47.10
Third Quarter	**$ 59.43**	**$ 54.20**	$ 53.84	$ 48.50
Fourth Quarter	**$ 56.11**	**$ 38.23**	$ 55.02	$ 49.39

At February 17, 2015, there were 545 holders of record of our 180,826,973 outstanding common units. ONEOK and its affiliates own all of the Class B units, 19,800,000 common units and the entire 2 percent general partner interest in us, which together constituted a 37.8 percent ownership interest in us at December 31, 2014.

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, 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

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.

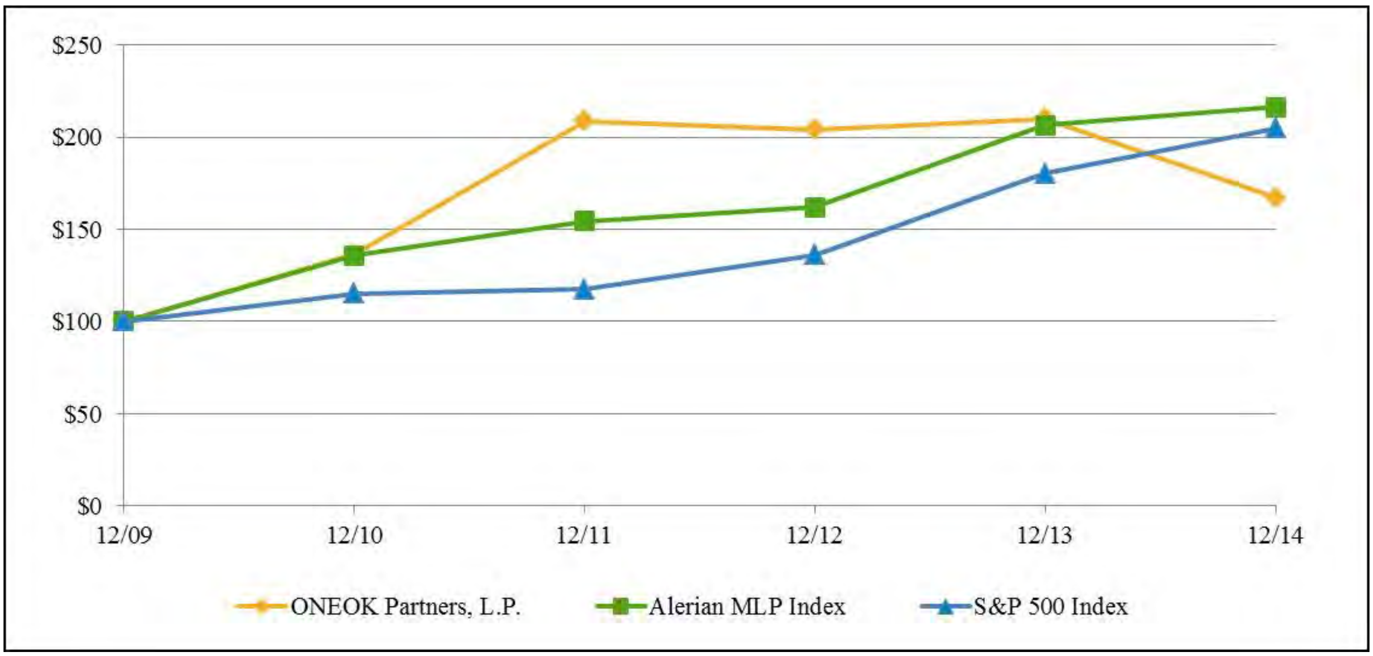
If our common unitholders vote at any time to remove ONEOK or its affiliates as our general partner, quarterly distributions payable on the Class B limited partner units would increase to 123.5 percent of the distributions payable with respect to the common units, and distributions payable upon liquidation 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 $1.1 billion, $909.7 million and $760.9 million for 2014, 2013 and 2012, respectively, which included an incentive distribution to our general partner of $305.0 million, $251.7 million and $186.1 million for 2014, 2013 and 2012, 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, 2009, and ending on December 31, 2014. 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, 2009, and at the End of Every Year Through December 31, 2014, Among ONEOK Partners, L.P., the S&P 500 Index and the Alerian MLP Index



	Cumulative Total Return									
	Years Ended December 31,									
	2010		2011		2012		2013		2014	
ONEOK Partners, L.P.	$	136.30	$	208.70	$	204.20	$	209.93	**$**	**167.03**
Alerian MLP Index (a)	$	135.63	$	154.39	$	161.84	$	206.50	**$**	**216.35**
S&P 500 Index	$	115.08	$	117.47	$	136.24	$	180.33	**$**	**204.94**

(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,				
	2014	**2013**	**2012**	**2011**	**2010**
	(Millions of dollars, except per unit data)				
Revenues	**$ 12,191.7**	$ 11,869.3	$ 10,182.2	$ 11,322.6	$ 8,675.9
Net income	**$ 911.3**	$ 804.0	$ 888.4	$ 830.9	$ 473.3
Net income attributable to ONEOK Partners, L.P.	**$ 910.3**	$ 803.6	$ 888.0	$ 830.3	$ 472.7
Limited partners' net income per unit	**$ 2.33**	$ 2.35	$ 3.04	$ 3.35	$ 1.75
Distributions paid per common unit (a)	**$ 3.010**	$ 2.870	$ 2.590	$ 2.325	$ 2.230
Total assets	**$ 14,634.5**	$ 12,862.6	$ 10,959.2	$ 8,946.7	$ 7,920.1
Long-term debt, including current maturities	**$ 6,046.0**	$ 6,052.5	$ 4,811.3	$ 3,876.6	$ 2,818.5

(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 our "Description of the Business" in Item 1, Business, and our audited Consolidated Financial Statements and the Notes to Consolidated Financial Statements in this Annual Report.

RECENT DEVELOPMENTS

The following discussion highlights some of our planned activities, recent achievements and significant issues affecting us. 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 Operation, our Consolidated Financial Statements and Notes to Consolidated Financial Statements for additional information.

Commodity Prices - Due in part to the rapid growth in crude oil production in the United States, the global supply of crude oil has exceeded demand and led to a dramatic fall in crude oil prices. Commodity prices declined sharply in the fourth quarter 2014 and continued to decline into early 2015. WTI crude oil prices declined to less than $50.00 per barrel in early 2015, compared with approximately $90.00 per barrel in September 2014. NYMEX natural gas prices also declined to approximately $3.00 per MMBtu in early 2015, compared with prices in excess of $4.00 per MMBtu in September 2014. The decline in crude oil prices has also contributed to lower NGL product prices, as well as narrow NGL product price differentials.

We expect lower commodity prices and narrow location and product price differentials to persist throughout 2015. Producer capital investment is expected to decrease, which combined with production declines and reduced drilling activity, is expected to slow natural gas and NGL supply growth. The lower commodity prices and slower supply growth are expected to adversely impact our results of operations and cash flows in 2015, particularly in our Natural Gas Gathering and Processing segment where revenues are derived primarily from commodity-based contracts with fee components.

We continue to expect that natural gas liquids volumes will be affected negatively in our Natural Gas Liquids segment as a result of ethane rejection. We expect ethane rejection will persist until new world-scale ethylene production capacity, which is anticipated to begin coming on line in 2017, significantly increases ethane demand. Market conditions may result in periods where it is economical to recover the ethane component in the natural gas liquids stream. Ethane rejection is expected to have a significant impact on our financial results through 2017. However, our Natural Gas Liquids segment's integrated assets enable it to mitigate partially the impact of ethane rejection through minimum volume commitments and our ability to utilize the transportation capacity made available due to ethane rejection to capture additional NGL location price differentials in our optimization activities.

Growth Projects - Through 2014, crude oil and natural gas producers continued to drill aggressively for crude oil and NGL-rich natural gas in many regions where we have operations, including the Bakken Shale and Three Forks formations in the Williston Basin; the Niobrara Shale and other formations in the Powder River Basin; and in the Cana-Woodford Shale, Woodford Shale, Mississippian Lime, Springer Shale, Stack and SCOOP areas in the Mid-Continent region. In response to this increased 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 totaling approximately $5.9 billion from 2010 through 2014 and we have approximately $2.1 billion to $3.0 billion of projects in various stages of construction, including approximately $2.2 billion in new projects and acquisitions announced in 2014, to meet the needs of natural gas producers and processors in these regions, as well as enhance our natural gas liquids fractionation, distribution and storage infrastructure in the Gulf Coast region. The execution of these capital investments aligns with our strategy to generate consistent growth and sustainable earnings. Our acreage dedications and contractual commitments from producers and natural gas processors in regions associated with our growth projects are expected to provide incremental cash flows and long-term fee-based earnings.

While reduced producer drilling activity is expected to slow supply growth, we expect to complete our previously announced projects to meet producers' demand for our gathering, processing fractionation and transportation services. However, we have suspended capital expenditures for certain natural gas processing plants and related infrastructure to align with the needs of our customers. We expect to resume our suspended capital-growth projects as soon as market conditions improve. 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.

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

West Texas LPG - In November 2014, we acquired the West Texas LPG system for approximately $800 million. See additional discussion in the "Financial Results and Operating Information" section in our Natural Gas Liquids segment and Note B of the Notes to Consolidated Financial Statements.

Bighorn Gas Gathering Impairment Charge - As a result of the continued decline in dry natural gas volumes gathered in the coal-bed methane area of the Powder River Basin and the operator recording an impairment of the underlying assets of Bighorn Gas Gathering in September 2014, we reviewed our equity method investment in Bighorn Gas Gathering as of September 30, 2014, and recorded noncash impairment charges totaling $76.4 million. See additional discussion in the "Financial Results and Operating Information" section in our Natural Gas Gathering and Processing segment.

Cash Distributions - During 2014, we paid cash distributions totaling $3.01 per unit, an increase of approximately 5 percent over the $2.87 per unit paid during 2013. In January 2015, our general partner declared a cash distribution of $0.79 per unit ($3.16 per unit on an annualized basis) for the fourth quarter 2014, an increase of approximately 8 percent over the $0.73 declared in January 2014.

Equity Issuances - In May 2014, we completed an underwritten public offering of approximately 13.9 million common units at a public offering price of $52.94 per common unit, generating net proceeds of approximately $729.5 million, including ONEOK Partners GP's contribution 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 2014, we sold approximately 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.

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

Transactions with Affiliates - For the three months ended March 31, 2014, we had transactions with our affiliate ONEOK Energy Services Company, a subsidiary of ONEOK. Our Natural Gas Gathering and Processing segment sold natural gas to ONEOK Energy Services Company, and our Natural Gas Pipelines segment provided transportation and storage services to ONEOK Energy Services Company. Additionally, our Natural Gas Gathering and Processing and Natural Gas Liquids segments purchased a portion of the natural gas used in their operations from ONEOK Energy Services Company. Prior to March 31, 2014, all of our Natural Gas Gathering and Processing segment's commodity derivative financial contracts were with ONEOK Energy Services Company, and it entered into similar commodity derivative financial contracts with third parties at our direction and on our behalf. On March 31, 2014, ONEOK completed the accelerated wind down of ONEOK Energy Services Company. In the first quarter 2014, outstanding commodity derivative positions with third parties entered into by ONEOK Energy Services Company on our behalf were transferred to us. Beginning in the second quarter 2014, we enter into all commodity derivative financial contracts directly with unaffiliated third parties.

On January 31, 2014, ONEOK completed the separation of its former natural gas distribution business into ONE Gas. We continue to enter into commodity sales and transportation and storage services transactions with ONE Gas after the separation, and these transactions are reflected as unaffiliated, third-party transactions beginning in February 2014.

ONEOK and its subsidiaries continue to be our sole general partner and own limited partners units, which together at December 31, 2014, represented a 37.8 percent interest in us.

FINANCIAL RESULTS AND OPERATING INFORMATION

Consolidated Operations

The following table sets forth certain selected consolidated financial results for the periods indicated:

Financial Results	Years Ended December 31, 2014	2013	2012	Variances 2014 vs. 2013 Increase (Decrease)		Variances 2013 vs. 2012 Increase (Decrease)	
			(Millions of dollars)				
Revenues							
Commodity sales	**$ 10,725.0**	$ 10,549.2	$ 9,010.2	**$ 175.8**	**2 %**	$ 1,539.0	17 %
Services	**1,466.7**	1,320.1	1,172.0	**146.6**	**11 %**	148.1	13 %
Total revenues	**12,191.7**	11,869.3	10,182.2	**322.4**	**3 %**	1,687.1	17 %
Cost of sales and fuel	**10,088.6**	10,222.2	8,540.4	**(133.6)**	**(1)%**	1,681.8	20 %
Net margin	**2,103.1**	1,647.1	1,641.8	**456.0**	**28 %**	5.3	— %
Operating costs	**669.7**	521.6	482.5	**148.1**	**28 %**	39.1	8 %
Depreciation and amortization	**291.2**	236.7	203.1	**54.5**	**23 %**	33.6	17 %
Gain (loss) on sale of assets	**6.6**	11.9	6.7	**(5.3)**	**(45)%**	5.2	78 %
Operating income	**$ 1,148.8**	$ 900.7	$ 962.9	**$ 248.1**	**28 %**	$ (62.2)	(6)%
Equity earnings from investments	**$ 41.0**	$ 110.5	$ 123.0	**$ (69.5)**	**(63)%**	$ (12.5)	(10)%
Interest expense	**$ (281.9)**	$ (236.7)	$ (206.0)	**$ 45.2**	**19 %**	$ 30.7	15 %
Capital expenditures	**$ 1,746.0**	$ 1,939.3	$ 1,560.5	**$ (193.3)**	**(10)%**	$ 378.8	24 %
Cash paid for acquisitions, net of cash received	**$ 814.9**	$ 394.9	$ —	**$ 420.0**	*****	$ 394.9	*

* Percentage change is greater than 100 percent.

2014 vs. 2013 - Revenues and net margin 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. We experienced increased optimization, marketing and isomerization margins 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 differential 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 margin 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.

Equity earnings decreased for 2014, compared with 2013, due primarily to noncash impairment charges totaling $76.4 million related to our equity method investment in Bighorn Gas Gathering in our Natural Gas Gathering and Processing 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.

2013 vs. 2012 - Revenues and net margin for 2013, compared with 2012, increased due primarily to higher natural gas and NGL volumes gathered, processed and sold from our completed capital projects, offset partially by lower net realized natural gas and NGL product prices and ethane rejection. The increase in natural gas supply resulting from the development of nonconventional resource areas in North America contributed to lower NGL prices, narrower NGL location price differentials and narrower natural gas location and seasonal price differentials in the markets we serve, compared with 2012. However, in December 2013, the price of propane increased significantly, and the differential between the Conway, Kansas, and Mont Belvieu, Texas, markets for propane also widened in favor of Conway, Kansas, due to colder than normal weather and lower propane inventory levels. The price of propane in the Mid-Continent market and the wider location price differentials between the Mid-Continent and Gulf Coast centers peaked in late January 2014 and moderated by the end of February 2014 as supply and demand rebalanced.

NGL location price differentials were significantly narrower between the Mid-Continent market center at Conway, Kansas, and the Gulf Coast market center at Mont Belvieu, Texas, for 2013, compared with 2012, due primarily to strong NGL production growth from the development of NGL-rich areas, exceeding the petrochemical industry's capacity to consume the increased supply resulting in higher ethane inventory levels at Mont Belvieu. Additionally, an unusually long maintenance outage season in the petrochemical industry during 2013 reduced ethane demand, which also contributed to the higher ethane inventory levels.

The differential between the composite price of NGL products and the price of natural gas, particularly the differential between ethane and natural gas, influenced the volume of NGLs recovered from natural gas processing plants. The low ethane prices resulted in ethane rejection at most of our natural gas processing plants and our customers' natural gas processing plants connected to our natural gas liquids system in the Mid-Continent and Rocky Mountain regions during 2013.

Operating costs and depreciation and amortization expense increased for 2013, compared with 2012, 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.

Interest expense increased for 2013, compared with 2012, primarily as a result of higher interest costs incurred associated with a full year of interest costs on our issuance of $1.3 billion of senior notes in September 2012 and interest costs on our issuance of $1.25 billion of senior notes in September 2013. This was offset partially by higher capitalized interest associated with our investments in the growth projects in our Natural Gas Gathering and Processing and Natural Gas Liquids segments.

Capital expenditures increased for 2013, compared with 2012, due primarily to the growth projects in our Natural Gas Gathering and Processing and Natural Gas Liquids segments. In 2013, we also acquired a business in the Niobrara Shale formation of the Power River Basin and purchased the remaining 30 percent interest in the Maysville, Oklahoma, natural gas processing facility.

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 - Beginning in 2010, our Natural Gas Gathering and Processing segment has invested approximately $4.0 billion to $4.7 billion in growth projects in NGL-rich areas in the Williston Basin, the Powder River Basin, the Cana-Woodford Shale, the Springer Shale, the Stack and the SCOOP areas that we expect will enable us to meet the rapidly growing needs of crude oil and natural gas producers in those areas. Nearly all of the new natural gas production is from horizontally drilled and completed 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.

We have completed approximately $2.2 billion of the growth projects and acquisitions in this segment from 2010 through 2014, which include the following:

Completed Projects	Location	Capacity	Approximate Costs (a)	Completion Date
			(*In millions*)	
Rocky Mountain Region				
Garden Creek I processing plant and infrastructure	Williston Basin	100 MMcf/d	$360	December 2011
Stateline I & II processing plants and infrastructure	Williston Basin	200 MMcf/d	$565	September 2012/ April 2013
Divide County gathering system	Williston Basin	270 miles	$125	June 2013
Sage Creek processing plant and infrastructure (b)	Powder River Basin	50 MMcf/d	$152	September 2013
Garden Creek II processing plant and infrastructure	Williston Basin	100 MMcf/d	$300 - $310	August 2014
Garden Creek III processing plant and infrastructure	Williston Basin	100 MMcf/d	$300 - $310	October 2014
Mid-Continent Region				
30 percent interest in Maysville processing plant (b)	Cana-Woodford Shale	40 MMcf/d	$90	December 2013
Canadian Valley processing plant and infrastructure	Cana-Woodford Shale	200 MMcf/d	$255	March 2014
Total			$2,147 - $2,167	

(a) Excludes AFUDC.
(b) Acquisition.

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				
Sage Creek infrastructure	Powder River Basin	Various	$50	Fourth quarter 2015
Natural gas compression	Williston Basin	100 MMcf/d	$80-$100	Fourth quarter 2015
Lonesome Creek processing plant and infrastructure	Williston Basin	200 MMcf/d	$550-$680	Fourth quarter 2015
Stateline De-ethanizers	Williston Basin	26 MBbl/d	$60 - $80	Fourth quarter 2015
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			$1,815-$2,580	

(a) Excludes AFUDC.

As a result of announced reductions in crude oil and natural gas drilling activities by producers and our expectation of slower supply growth due to the recent decline in crude oil, natural gas and NGL prices, we have suspended capital expenditures for certain natural gas processing plants and field infrastructure. We expect to resume our suspended capital-growth projects as soon as market conditions improve. 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.

Rocky Mountain Region:

Williston Basin Processing Plants and related projects - We are constructing natural gas gathering and processing assets in the Williston Basin to meet the growing needs of crude oil and natural gas producers. When our announced projects are completed, we will have natural gas processing capacity of approximately 1.2 Bcf/d in the basin. We have acreage dedications of approximately 3 million net acres supporting these projects.

Garden Creek II Plant - The Garden Creek II natural gas processing plant was completed in August 2014.

Garden Creek III Plant - The Garden Creek III natural gas processing plant, originally scheduled for completion in the first quarter 2015, was completed in October 2014.

Natural Gas Compression - In July 2014, we announced we will construct additional natural gas compression across our Williston Basin system to take advantage of additional natural gas processing capacity at our Garden Creek and Stateline facilities by a total of 100 MMcf/d.

Lonesome Creek Plant - In November 2013, we announced we will construct the Lonesome Creek natural gas processing plant and related infrastructure, which will be located in McKenzie County, North Dakota. The plant and infrastructure will help address natural gas gathering and processing constraints in the region.

Stateline De-ethanizers - We plan to construct de-ethanizer towers at our Stateline natural gas processing plants, which are located in Williams County, North Dakota. Once completed, the de-ethanizer towers will remove ethane from the natural gas stream, which we expect to then be sold under a long-term, fee-based contract to a customer who plans to transport the ethane on a third-party pipeline.

Bear Creek Plant - In September 2014, we announced we will construct the Bear Creek natural gas processing plant and related infrastructure, which will be located in Dunn County, North Dakota. The plant and infrastructure will help alleviate pipeline inefficiencies in an area challenged by geographical constraints and severe terrain.

Demicks Lake Plant - In July 2014, we announced we will construct the Demicks Lake natural gas processing plant and related infrastructure, which will be located in northeast McKenzie County, North Dakota, to help further address natural gas gathering and processing constraints in the region.

Powder River Basin - We are constructing natural gas gathering and processing assets in the NGL-rich areas of the Powder River Basin, a region poised for significant growth in natural gas and NGL production volumes. We have acreage dedications of approximately 130,000 net acres supporting these projects.

Sage Creek Plant - In September 2013, we completed the acquisition of a 50 MMcf/d natural gas processing facility, the Sage Creek plant, and related natural gas gathering and natural gas liquids infrastructure. We plan to upgrade existing natural gas processing infrastructure and construct new natural gas gathering infrastructure to meet the growing production of NGL-rich natural gas in this area. We have supply contracts providing for long-term acreage dedications from producers in the area supporting this project.

Bronco Plant - In September 2014, we announced we will construct the Bronco natural gas processing plant and related natural gas gathering and natural gas liquids infrastructure in Campbell and Converse counties, Wyoming.

***Mid-Continent Region*:**

Cana-Woodford Shale, Woodford Shale, Springer Shale, Stack and SCOOP areas - We are constructing natural gas gathering and processing assets to meet the growing production of NGL-rich natural gas in the Cana-Woodford Shale, Woodford Shale, Springer Shale, Stack and SCOOP areas. When our announced projects are completed, our Oklahoma natural gas processing capacity will be approximately 900 MMcf/d. We have substantial acreage dedications from crude oil and natural gas producers supporting these plants.

Canadian Valley Plant - In March 2014, we completed the Canadian Valley natural gas processing plant, which is located in the Cana-Woodford Shale.

Knox Plant - In July 2014, we announced we will construct the Knox natural gas processing plant and related infrastructure, which will be located in Grady and Stephens Counties, Oklahoma. The plant and related infrastructure will gather and process liquids-rich natural gas from the Cana-Woodford Shale and the emerging SCOOP area and will be located in close proximity to our existing natural gas gathering and processing assets and natural gas and natural gas liquids pipelines.

For a discussion of our capital expenditure financing, see “Capital Expenditures” in “Liquidity and Capital Resources.”

Selected Financial Results - Our Natural Gas Gathering and Processing segment’s 2014 operating results reflect benefits from the following projects:

- the Garden Creek III natural gas processing plant, which was completed in October 2014;
- the Garden Creek II natural gas processing plant, which was completed in August 2014;
- the Canadian Valley natural gas processing plant, which was completed in March 2014;

- the acquisition of the remaining 30 percent undivided interest in the Maysville, Oklahoma, natural gas processing facility, which was acquired in December 2013;
- the acquisition of the Sage Creek natural gas processing plant in Wyoming in September 2013; and
- the Stateline II natural gas processing plant, which was completed in April 2013.

The completion of the Stateline II, Garden Creek II and Garden Creek III natural gas processing plants resulted in increased natural gas volumes gathered and processed in the Williston Basin, and completion of the Canadian Valley natural gas processing plant resulted in increased natural gas volumes gathered and processed in Oklahoma.

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 2014 vs. 2013		Variances 2013 vs. 2012	
Financial Results	**2014**	**2013**	**2012**	**Increase (Decrease)**		**Increase (Decrease)**	
				(*Millions of dollars*)			
NGL sales	**$ 1,434.4**	$ 1,095.5	$ 834.0	**$ 338.9**	**31 %**	$ 261.5	31 %
Condensate sales	**110.8**	113.2	100.2	**(2.4)**	**(2)%**	13.0	13 %
Residue natural gas sales	**1,140.5**	620.5	403.8	**520.0**	**84 %**	216.7	54 %
Gathering, compression, dehydration and processing fees and other revenue	**281.9**	222.3	177.7	**59.6**	**27 %**	44.6	25 %
Cost of sales and fuel	**2,305.7**	1,550.9	1,060.5	**754.8**	**49 %**	490.4	46 %
Net margin	**661.9**	500.6	455.2	**161.3**	**32 %**	45.4	10 %
Operating costs	**257.7**	193.3	164.0	**64.4**	**33 %**	29.3	18 %
Depreciation and amortization	**123.8**	103.9	83.0	**19.9**	**19 %**	20.9	25 %
Gain (loss) on sale of assets	**0.2**	0.4	2.2	**(0.2)**	**(50)%**	(1.8)	(82)%
Operating income	**$ 280.6**	$ 203.8	$ 210.4	**$ 76.8**	**38 %**	$ (6.6)	(3)%
Equity earnings (loss) from investments	**$ (56.1)**	$ 23.5	$ 29.1	**$ (79.6)**	*****	$ (5.6)	(19)%
Capital expenditures	**$ 898.9**	$ 774.4	$ 566.1	**$ 124.5**	**16 %**	$ 208.3	37 %
Cash paid for acquisitions	**$ —**	$ 241.9	$ —	**$ (241.9)**	**(100)%**	$ 241.9	*

* Percentage change is greater than 100 percent.

Commodity prices declined sharply in the fourth quarter 2014 and continued to decline into early 2015. WTI crude oil prices declined to less than $50.00 per barrel in early 2015, compared with approximately $90.00 per barrel in September 2014. NYMEX natural gas prices also declined to approximately $3.00 per MMBtu in early 2015, compared with prices in excess of $4.00 per MMBtu in September 2014. We expect lower commodity prices to persist throughout 2015. In response, crude oil and natural gas exploration and production capital investment is expected to decrease, which combined with production declines and reduced drilling activity is expected to slow crude oil, natural gas and NGL supply growth. We expect crude oil and natural gas producers to focus capital spending and drilling activities on core locations that are most economical to develop. The lower commodity price environment is expected to have an adverse impact on our Natural Gas Gathering and Processing segment's financial results in 2015.

2014 vs. 2013 - Net margin 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 changes in contract mix; 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.

Equity earnings (loss) from investments decreased due to $76.4 million in impairment charges in the third quarter 2014 on our investment in Bighorn Gas Gathering. See additional discussion in "Equity Investments" below.

Capital expenditures increased 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.

2013 vs. 2012 - Net margin increased primarily as a result of the following:

- an increase of $100.1 million due primarily to volume growth in the Williston Basin from our Stateline I and Stateline II natural gas processing plants, and increased well connections resulting in higher natural gas volumes gathered, compressed, processed, transported and sold, higher NGL volumes sold and higher fees; and
- an increase of $6.4 million due to a contract settlement in 2013; offset partially by
- a decrease of $41.7 million due primarily to lower net realized NGL prices;
- a decrease of $13.4 million due primarily to changes in contract mix and terms associated with our volume growth; and
- a decrease of $3.5 million due to lower dry natural gas volumes gathered as a result of continued declines in coal-bed methane production in the Powder River Basin.

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

- an increase of $16.8 million in higher materials and supplies, and outside service expenses;
- an increase of $10.3 million in employee-related costs due to higher labor and employee benefit costs, offset partially by lower incentive compensation costs; and
- an increase of $2.2 million due to higher ad valorem taxes.

Depreciation and amortization expense increased due to the completion of the Stateline I and Stateline II natural gas processing plants in the Williston Basin, the completion of well connections and infrastructure projects supporting our volume growth in the Williston Basin and the acquisition of the Sage Creek plant in Wyoming.

Equity earnings from investments decreased due primarily to lower NGL prices and declines in dry natural gas volumes gathered by certain of our equity investments in the Powder River Basin.

Capital expenditures increased due to our growth projects discussed above. In 2013, we also completed the Sage Creek acquisition in the NGL-rich Niobrara Shale area of the Powder River Basin and acquired the remaining 30 percent interest in the Maysville, Oklahoma, natural gas processing facility.

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)	**2014**	**2013**	**2012**
Natural gas gathered (*BBtu/d*)	**1,733**	1,347	1,119
Natural gas processed (*BBtu/d*) (b)	**1,534**	1,094	866
NGL sales (*MBbl/d*)	**104**	79	61
Residue natural gas sales (*BBtu/d*)	**714**	497	397
Realized composite NGL net sales price (*$/gallon*) (c)	**$ 0.93**	$ 0.87	$ 1.06
Realized condensate net sales price (*$/Bbl*) (c)	**$ 76.43**	$ 86.00	$ 88.22
Realized residue gas net sales price (*$/MMBtu*) (c)	**$ 3.92**	$ 3.53	$ 3.87
Average fee rate (*$MMBtu*)	**$ 0.36**	$ 0.34	$ 0.35

(a) - Includes volumes for consolidated entities only.
(b) - Includes volumes at company-owned and third-party facilities.
(c) - Presented net of the impact of hedging activities on our equity volumes.

Natural gas gathered and processed, NGL sales and residue natural gas sales increased due to the completion of growth projects and/or acquisitions in the Williston Basin, Powder River Basin and Mid-Continent areas, offset partially by declines in volumes in the coal-bed methane area of the Powder River Basin. The quantity and composition of NGLs and natural gas continue to change as our new natural gas processing plants in the Williston Basin and Mid-Continent are placed in service. In March 2014, our Canadian Valley plant in Oklahoma was completed, which has better ethane rejection capabilities than our other processing plants in the Mid-Continent region. As a result, our realized composite NGL net sales price increased while most individual NGL product prices were lower. Our Garden Creek I, Garden Creek II, Garden Creek III, Stateline I and Stateline II plants in the Williston Basin have the capability to recover ethane when economic conditions warrant but did not do so in 2014. Our equity NGL volumes are expected to be weighted more toward propane due to expected ethane rejection.

	Years Ended December 31,		
Equity Volume Information (a)	**2014**	**2013**	**2012**
NGL sales (*MBbl/d*)	**16.5**	14.4	11.6
Condensate sales (*MBbl/d*)	**3.1**	2.4	2.3
Residue natural gas sales (*BBtu/d*)	**118.2**	71.7	48.8

(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 in exchange for our services. See discussion regarding our commodity price risk under "Commodity Price Risk" in Item 7A, Quantitative and Qualitative Disclosures about Market Risk.

Equity Investments - 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 coal-bed methane development activities and production declines in the dry natural gas formations of the Powder River Basin have resulted in lower natural gas volumes available to be gathered. While the reserve potential in the dry natural gas formations of the Powder River Basin still exists, future drilling and development in this area will be affected by commodity prices and producers' alternative prospects.

During 2014, the coal-bed methane volumes gathered on the Bighorn Gas Gathering system, in which we own a 49 percent equity interest and which operates in the coal-bed methane area of the Powder River Basin, declined at a rate greater than in prior periods and greater than expected. Due to these additional declines in volumes, Bighorn Gas Gathering recorded an impairment of its underlying assets in September 2014, when the operator determined that the volume decline would be sustained for the foreseeable future. As a result of these developments, we reviewed our equity method investment in Bighorn Gas Gathering for impairment and recorded noncash impairment charges of $76.4 million related to Bighorn Gas Gathering. The noncash impairment charges are included in equity earnings from investments in our accompanying Consolidated Statements of Income. The net book value of our equity method investment in Bighorn Gas Gathering is $7.9 million at December 31, 2014, and no equity method goodwill remains. We determined there were no impairments to investments in unconsolidated affiliates in 2013 or 2012.

A continued decline in volumes gathered in the coal-bed methane area of the Powder River Basin may reduce our ability to recover the carrying value of our equity investments in this area and could result in additional noncash charges to earnings. The net book value of our remaining equity method investments in this dry natural gas area is $206.0 million, which includes $130.5 million of equity method goodwill. We expect the energy commodity price environment to remain depressed for at least the near term, which has caused producers to announce plans for reduced drilling for crude oil and natural gas, which we expect will slow volume growth or reduce volumes of natural gas delivered to systems owned by our equity method investments.

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. Increasing crude oil, natural gas and NGL production resulting from this activity and higher petrochemical industry demand for NGL products 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 in the next two to four years, and international demand for NGLs, particularly propane, also is increasing and is expected to continue to do so in the future.

Beginning in 2010, our Natural Gas Liquids segment has invested approximately $4.0 billion in NGL-related projects. These investments will accommodate the transportation and fractionation of growing NGL supply from shale and other resource development areas across our asset base and alleviate infrastructure constraints between the Mid-Continent and Gulf Coast market centers to meet increasing petrochemical industry and NGL export demand in the Gulf Coast. Over time, these growing fee-based NGL volumes are expected to fill much of our natural gas liquids pipeline capacity used historically to capture the NGL location price differentials between the two market centers.

We have completed approximately $3.8 billion in growth projects and acquisitions in this segment from 2010 through 2014, which include the following:

Completed Projects	Capacity	Approximate Costs (a)	Completion Date
		(*In millions*)	
Sterling I expansion	15 MBbl/d	$36	November 2011
Cana-Woodford/Granite Wash NGL plant connections	77 MBbl/d	$220	April 2012
Bushton fractionator expansion	60 MBbl/d	$117	September 2012
Bakken NGL Pipeline	60 MBbl/d	$455	April 2013
Overland Pass Pipeline expansion	60 MBbl/d	$36	April 2013
Ethane Header pipeline	400 MBbl/d	$23	April 2013
Sage Creek NGL infrastructure (b)	Various	$153	September 2013
MB-2 Fractionator	75 MBbl/d	$375	December 2013
Ethane/Propane Splitter	40 MBbl/d	$46	March 2014
Sterling III Pipeline and reconfigure Sterling I and II	193 MBbl/d	$808	March 2014
Bakken NGL Pipeline expansion - Phase I	75 MBbl/d	$75-$90	September 2014
Niobrara NGL Lateral	90 miles	$70-$75	September 2014
West Texas LPG (b)	2,600 miles	$800	November 2014
MB-3 Fractionator	75 MBbl/d	$520-$540	December 2014
Total		$3,734-$3,774	

(a) Excludes AFUDC.
(b) Acquisition.

We have the following projects in various stages of construction:

Projects in Progress	Capacity	Approximate Costs (a)	Expected Completion Date
		(*In millions*)	
NGL Pipeline and Hutchinson Fractionator infrastructure	95 miles	$110-$125	First quarter 2015
Bakken NGL Pipeline expansion - Phase II	25 MBbl/d	$100	Second quarter 2016
Bear Creek NGL infrastructure	40 miles	$35-$45	Third quarter 2016
Bronco NGL infrastructure	65 miles	$45-$60	Suspended
Demicks Lake NGL infrastructure	12 miles	$10-$15	Suspended
Total		$300-$345	

(a) Excludes AFUDC.

As a result of announced reductions in crude oil and natural gas drilling activities and our expectation of slower supply growth due to the recent declines in 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 expect to resume our suspended capital-growth projects as soon as market conditions improve. 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.

Ethane/Propane Splitter - In March 2014, we placed in service an ethane/propane splitter at our Mont Belvieu storage facility to split ethane/propane mix into purity ethane to meet the needs of petrochemical customers, which is expected to grow over the long-term. The facility is capable of producing 32 MBbl/d of purity ethane and 8 MBbl/d of propane.

Sterling III Pipeline - In March 2014, we completed a 550-mile natural gas liquids pipeline, which has the flexibility to transport either unfractionated NGLs or NGL products from the Mid-Continent to the Gulf Coast. The pipeline is designed to transport up to 193 MBbl/d of NGL production from Medford, Oklahoma, to our storage and fractionation facilities in Mont

Belvieu, Texas. We have multiyear supply commitments from producers and natural gas processors for approximately 75 percent of the pipeline's capacity. Installation of additional pump stations could expand the capacity of the pipeline to 260 MBbl/d. This project also included the reconfiguration of our existing Sterling I and Sterling II pipelines to transport either unfractionated NGLs or NGL products. The reconfiguration was completed in July 2014.

Bakken NGL Pipeline expansion, Phase I - The first expansion, completed in September 2014, increased the pipeline's capacity to 135 MBbl/d from the original capacity of 60 MBbl/d, with the second expansion expected to bring the pipeline's capacity to 160 MBbl/d. These expansions will accommodate the growing NGL supply from the Williston and Powder River Basins.

Niobrara NGL Lateral - We constructed new natural gas liquids pipeline infrastructure to connect the Sage Creek natural gas processing plant and a third-party natural gas processing plant to our Bakken NGL Pipeline, which was completed in September 2014.

West Texas LPG Acquisition - In November 2014, we completed our acquisition of an 80 percent interest in the West Texas LPG Pipeline Limited Partnership 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. 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 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 are expected to provide us additional fee-based earnings and our natural gas liquids infrastructure with access to a new natural gas liquids supply basin.

MB-3 Fractionator - In December 2014, we completed the MB-3 fractionator. The MB-3 fractionator is located near our storage facility in Mont Belvieu, Texas. In addition, we expanded and upgraded our existing natural gas liquids gathering and pipeline infrastructure, which includes new connections to natural gas processing facilities and increasing the capacity of our Arbuckle and Sterling II natural gas liquids pipelines. We have multiyear supply commitments from producers and natural gas processors for approximately 80 percent of the fractionator's capacity.

Natural gas liquids pipeline and modification of Hutchinson fractionation infrastructure - We are constructing a new 95-mile natural gas liquids pipeline that will connect our existing natural gas liquids fractionation and storage facilities in Hutchinson, Kansas, to similar facilities in Medford, Oklahoma. The project also included modifications that were completed in December 2014 to existing natural gas liquids fractionation infrastructure at Hutchinson, Kansas, increasing fractionation capacity by 20 MBbl/d, to accommodate additional unfractionated NGLs produced in the Williston Basin.

Bakken NGL Pipeline expansion, Phase II - The second expansion will increase the pipeline's capacity to 160 MBbl/d from the current capacity of 135 MBbl/d.

Bear Creek natural gas liquids infrastructure - We announced in September 2014 our plan to build new natural gas liquids pipeline infrastructure to connect the Bear Creek natural gas processing plant to our Bakken NGL Pipeline.

Bronco natural gas liquids infrastructure - We announced in September 2014 our plan to build new natural gas liquids pipeline infrastructure to connect the Bronco natural gas processing plant to our Bakken NGL Pipeline.

Demicks Lake natural gas liquids infrastructure - We announced in July 2014 our plan to build new natural gas liquids pipeline infrastructure to connect the Demicks Lake natural gas processing plant to our Bakken NGL Pipeline.

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

Selected Financial Results - Our Natural Gas Liquids segment's 2014 operating results reflect the benefits from the following completed growth projects:

- the West Texas LPG acquisition, which was completed in November 2014;
- the Niobrara NGL Lateral, which was completed in September 2014;
- the Bakken NGL Pipeline expansion, Phase I, which was completed in September 2014;
- the Sterling III Pipeline and reconfigurations to Sterling I and II, which were completed in March 2014;
- the Ethane/Propane Splitter, which was completed in March 2014;
- the MB-2 Fractionator, which was completed in December 2013;
- the Sage Creek NGL infrastructure, which was completed in September 2013;
- the Bakken NGL Pipeline, which was completed in April 2013;

- the expansion of the Overland Pass Pipeline, which was completed in the second quarter 2013; and
- the Ethane Header Pipeline, which was completed in April 2013.

These projects have resulted in additional natural gas liquids volumes gathered, fractionated and transported across our natural gas liquids systems; however, the volumes fractionated and transported decreased in 2014 due to ethane rejection. We expect these investments along with our other announced growth projects will accommodate the growing NGL supply from shale and other resource development areas across our asset base and will continue to alleviate infrastructure constraints between the Mid-Continent and Texas Gulf coast regions to meet the increasing petrochemical industry and NGL export demand.

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 2014 vs. 2013		Variances 2013 vs. 2012	
Financial Results	**2014**	**2013**	**2012**	**Increase (Decrease)**		**Increase (Decrease)**	
			(*Millions of dollars*)				
NGL and condensate sales	**$ 9,462.4**	$ 9,857.7	$ 8,479.7	**$ (395.3)**	**(4)%**	$ 1,378.0	16 %
Exchange service and storage revenues	**988.8**	839.3	707.6	**149.5**	**18 %**	131.7	19 %
Transportation revenues	**94.2**	81.0	69.3	**13.2**	**16 %**	11.7	17 %
Cost of sales and fuel	**9,435.3**	9,908.1	8,349.3	**(472.8)**	**(5)%**	1,558.8	19 %
Net margin	**1,110.1**	869.9	907.3	**240.2**	**28 %**	(37.4)	(4)%
Operating costs	**296.4**	236.6	223.8	**59.8**	**25 %**	12.8	6 %
Depreciation and amortization	**124.1**	89.2	74.3	**34.9**	**39 %**	14.9	20 %
Gain (loss) on sale of assets	**(0.6)**	0.8	(1.0)	**(1.4)**	*	1.8	*
Operating income	**$ 689.0**	$ 544.9	$ 608.2	**$ 144.1**	**26 %**	$ (63.3)	(10)%
Equity earnings from investments	**$ 27.3**	$ 22.0	$ 20.7	**$ 5.3**	**24 %**	$ 1.3	6 %
Allowance for equity funds used during construction	**$ 14.7**	$ 30.4	$ 13.5	**$ (15.7)**	**(52)%**	$ 16.9	*
Capital expenditures	**$ 798.0**	$ 1,128.3	$ 968.5	**$ (330.3)**	**(29)%**	$ 159.8	16 %
Cash paid for acquisitions, net of cash received	**$ 800.0**	$ 153.0	$ —	**$ 647.0**	*	$ 153.0	*

* Percentage change is greater than 100 percent.

Several factors contributed to increased propane demand and price in the first quarter 2014, which impacted our results of operations in 2014. In the fourth quarter 2013, we experienced high propane demand for crop drying and increased heating demand due to colder than normal weather that continued into the first quarter 2014. In response to increased demand, propane prices at the Mid-Continent market center at Conway, Kansas, increased significantly, compared with propane prices at the Gulf Coast market center at Mont Belvieu, Texas. To help meet the demand and capture the wider location price differentials between these two markets, we utilized our assets to deliver more propane into the Mid-Continent region from the Gulf Coast region. 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.

The recent volatility in crude oil prices has also impacted NGL prices, as NGL prices are generally linked to crude oil prices. These price decreases affected our NGL sales revenues and cost of sales.

Ethane rejection in the Rocky Mountain and Mid-Continent regions continued in 2014 as expected, resulting in available capacity on our pipelines that connect the Mid-Continent and Gulf Coast market centers, a portion of which we were able to utilize for optimization activities, including the delivery of propane into the Mid-Continent region during the first quarter 2014. Severely cold weather in the first quarter 2014 caused wellhead freeze-offs, which also reduced volumes.

<u>2014 vs. 2013</u> - Net margin increased primarily as a result of the following:

- an increase of $157.4 million in exchange-services and transportation margins, 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 optimization and marketing margins, which resulted from a $31.4 million increase due primarily to wider realized NGL product price differentials; a $25.2 million increase in marketing margins 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 the depreciation associated with our completed capital projects.

Equity earnings 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. Allowance for equity funds used during construction decreased due to the completion of all of our regulated projects.

2013 vs. 2012 - Net margin decreased primarily as a result of the following:

- a decrease of $162.7 million in optimization and marketing margins, which resulted from a $202.5 million decrease due primarily to significantly narrower NGL location price differentials. This decrease was offset partially by an increase of $35.7 million due primarily to more favorable NGL product price differentials;
- a decrease of $48.8 million resulting from the impact of ethane rejection, which resulted in lower NGL volumes; and
- a decrease of $22.4 million related to lower isomerization volumes, resulting from the narrower price differential between normal butane and iso-butane; offset partially by
- an increase of $166.5 million in exchange-services margins, which resulted from higher NGL volumes gathered, contract renegotiations for higher fees for our NGL exchange-services activities and higher revenues from customers with minimum volume obligations;
- an increase of $19.5 million due to the impact of operational measurement gains of approximately $9.7 million in 2013, compared with losses of approximately $9.8 million in 2012; and
- an increase of $10.5 million in storage margins due primarily to contract renegotiations.

Operating costs increased primarily as a result of the growth of our operations and reflect the following:

- an increase of $5.4 million due to higher ad valorem taxes related to our completed capital projects; and
- an increase of $5.0 million in employee-related costs due to higher labor and employee benefit costs due to the growth of our operations related to our completed capital projects, offset partially by lower incentive compensation costs.

Depreciation and amortization expense increased due primarily to the depreciation associated with our completed capital projects.

Equity earnings increased compared with 2012 due primarily to higher volumes delivered to Overland Pass Pipeline from our Bakken NGL Pipeline that was placed in service in April 2013, offset partially by reduced volumes as a result of ethane rejection. The impact of ethane rejection reduced equity earnings by $13.3 million compared with 2012.

Capital expenditures and the allowance for equity funds used during construction increased due primarily to our growth projects discussed above. In 2013, we also completed the Sage Creek acquisition in the NGL-rich Niobrara Shale area of the Powder River Basin that included natural gas liquids gathering pipelines.

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

	Years Ended December 31,		
Operating Information	**2014**	**2013**	**2012**
NGL sales (*MBbl/d*)	**615**	657	572
NGLs transported - gathering lines (*MBbl/d*) (a)	**533**	547	520
NGLs fractionated (*MBbl/d*) (b)	**522**	535	574
NGLs transported - distribution lines (*MBbl/d*) (a)	**408**	435	491
Average Conway-to-Mont Belvieu OPIS price differential - ethane in ethane/propane mix (*$/gallon*)	**$ 0.05**	$ 0.04	$ 0.17

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

<u>2014 vs. 2013</u> - NGLs transported on gathering lines and NGLs fractionated decreased due primarily to the termination of a low margin 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.

<u>2013 vs. 2012</u> - NGLs transported on gathering lines increased due primarily to increased volumes from the Williston Basin made available by our completed Bakken NGL Pipeline and increased volumes in the Mid-Continent region and Texas made available through our Cana-Woodford Shale and Granite Wash projects, offset partially by decreases in NGL volumes gathered as a result of ethane rejection.

NGLs fractionated decreased due primarily to decreased volumes as a result of ethane rejection during 2013, offset partially by higher volumes supplied from the Williston Basin made available by our completed Bakken NGL Pipeline.

NGLs transported on distribution lines decreased due primarily to decreased volumes as a result of ethane rejection.

Natural Gas Pipelines

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:

Financial Results	Years Ended December 31, 2014	2013	2012	Variances 2014 vs. 2013 Increase (Decrease)		Variances 2013 vs. 2012 Increase (Decrease)	
	(Millions of dollars)						
Transportation revenues	**$ 270.5**	$ 233.0	$ 220.9	**$ 37.5**	**16 %**	$ 12.1	5 %
Storage revenues	**64.0**	70.4	68.7	**(6.4)**	**(9)%**	1.7	2 %
Natural gas sales and other revenues	**15.9**	22.1	30.8	**(6.2)**	**(28)%**	(8.7)	(28)%
Cost of sales	**21.9**	39.8	34.3	**(17.9)**	**(45)%**	5.5	16 %
Net margin	**328.5**	285.7	286.1	**42.8**	**15 %**	(0.4)	— %
Operating costs	**111.0**	101.2	101.9	**9.8**	**10 %**	(0.7)	(1)%
Depreciation and amortization	**43.3**	43.5	45.7	**(0.2)**	**— %**	(2.2)	(5)%
Gain (loss) on sale of assets	**6.8**	10.6	5.3	**(3.8)**	**(36)%**	5.3	100 %
Operating income	**$ 181.0**	$ 151.6	$ 143.8	**$ 29.4**	**19 %**	$ 7.8	5 %
Equity earnings from investments	**$ 69.8**	$ 65.0	$ 73.2	**$ 4.8**	**7 %**	$ (8.2)	(11)%
Capital expenditures	**$ 43.0**	$ 34.7	$ 25.4	**$ 8.3**	**24 %**	$ 9.3	37 %
Cash paid for acquisitions	**$ 14.0**	$ —	$ —	**$ 14.0**	*****	$ —	— %

* Percentage change is greater than 100 percent.

2014 vs. 2013 - Net margin 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 compared with $10.5 million in the prior year.

Equity earnings from our 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. Substantially all of Northern Border Pipeline's long-haul transportation capacity has been contracted through March 2016.

2013 vs. 2012 - Operating income increased in 2013, compared with 2012, reflecting an increase in transportation margins of $9.6 million due primarily to higher rates on Guardian Pipeline and higher contracted capacity with natural gas producers on our intrastate pipelines, offset partially by a decrease of $3.9 million from lower net retained fuel. Operating costs included an increase of $2.4 million due to higher employee-benefit costs. Gain on sale of assets increased in 2013 from 2012 due primarily to a $10.5 million gain on excess pad gas sales in 2013 as a result of storage optimization review that resulted in additional working natural gas capacity of 2.0 Bcf; 2012 results reflected a gain on sale of a natural gas pipeline lateral of $5.7 million.

Equity earnings from our investments decreased in 2013, compared with 2012, due to reduced transportation rates resulting from a Northern Border Pipeline rate settlement, effective January 1, 2013. The new long-term transportation rates are approximately 11 percent lower than previous rates, which reduced our equity earnings and cash distributions compared with 2012.

Operating Information (a)	Years Ended December 31, 2014	2013	2012
Natural gas transportation capacity contracted (*MDth/d*)	**5,781**	5,524	5,366
Transportation capacity subscribed	**91%**	90%	89%
Average natural gas price			
Mid-Continent region (*$/MMBtu*)	**$ 4.33**	$ 3.61	$ 2.64

(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 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 to remain relatively stable with growth in certain market areas as the development of shale and other resource areas continues.

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, and we do not expect the settlement to materially impact us.

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. 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, 2014, 2013 and 2012, to net income, which is the nearest comparable GAAP financial measure, is as follows:

(*Unaudited*)	2014	Years Ended December 31, 2013	2012
Reconciliation of Net Income to Adjusted EBITDA		(*Thousands of dollars*)	
Net income	**$ 911,335**	$ 803,983	$ 888,428
Interest expense	**281,908**	236,714	206,018
Depreciation and amortization	**291,236**	236,743	203,101
Impairment charges (a)	**76,412**	—	—
Income taxes	**12,668**	10,858	10,105
Allowance for equity funds used during construction	**(14,937)**	(30,522)	(13,648)
Adjusted EBITDA	**$ 1,558,622**	$ 1,257,776	$ 1,294,004

(a) - Amount includes $23.0 million for our proportionate share of the long-lived asset impairment charge of our equity method investment in Bighorn Gas Gathering and $53.4 million impairment charge for our investment in Bighorn Gas Gathering.

Adjusted EBITDA increased for the year ended December 31, 2014, compared with 2013, due primarily to increases in operating income, which are discussed 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 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.

LIQUIDITY AND CAPITAL RESOURCES

Part of our strategy is to grow through internally generated growth projects and acquisitions that strengthen and complement our existing assets. 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. We fund our operating expenses, debt service and cash distributions to our limited partners and general partner primarily with operating cash flows. Capital expenditures are funded by operating cash flows, short- and long-term debt and issuances of equity. We expect to continue to use these sources for liquidity and capital resource needs on both a short- and long-term basis. We have no guarantees of debt or other similar commitments to unaffiliated parties.

While our net margin is primarily derived from fee-based contracts, a portion of our net margin is dependent upon the prevailing and future prices for NGLs, crude oil and natural gas. Commodity prices are dependent on numerous factors beyond our control, such as overall crude oil and natural gas supply and demand and inventories in relevant markets, economic conditions, the global political environment, regulatory developments and competition from other energy sources. These commodity prices historically have been volatile and may be subject to significant fluctuations in the future. For example, WTI crude oil prices declined to less than $50.00 per barrel in early 2015, compared with approximately $90.00 per barrel in September 2014. NYMEX natural gas prices also declined to approximately $3.00 per MMBtu in early 2015, compared with prices in excess of $4.00 per MMBtu in September 2014.

We use hedges to partially mitigate our near-term sensitivity to fluctuations in the natural gas, crude oil and NGL prices received for our equity volumes. As of February 2015, we had hedged 80 percent, 33 percent and 44 percent of our expected 2015 equity natural gas, NGL and condensate volumes, respectively. Currently, we do not have hedges in place for any of our expected equity volumes beyond 2015.

We expect the energy commodity price environment to remain depressed for at least the near term, which has caused crude oil and natural gas producers to announce plans for reduced drilling for crude oil and natural gas, which we expect will slow volume growth, or reduce the volumes of natural gas and NGLs delivered on to our systems. These conditions are expected to adversely impact our results of operations and cash flows. If the current energy commodity price environment persists for a prolonged period or declines further, it could have a material adverse effect on our financial position, results of operations and cash flows.

We continue to have access to our Partnership Credit Agreement, which we expect to be adequate to fund short-term liquidity needs. In February 2015, we notified our lenders of our intent to exercise our option to increase the capacity of the facility to an aggregate of $2.4 billion by increased commitments from existing lenders and/or commitments from one or more new lenders, which is pending lenders' approval. While our lenders are not obligated to increase the capacity of the facility, we expect to receive sufficient commitments to increase the facility to $2.4 billion.

If the low commodity prices persist throughout 2015, we expect it to have an adverse impact on our volumes and margins. We are responding by aligning our operating costs and capital-growth projects with the needs of crude oil and natural gas producers, which includes suspending, reducing or eliminating certain capital-growth projects; limiting increases of distributions to our limited partners and negotiating various contract enhancements. We continue to seek opportunities to convert our POP contracts to fee-based contracts or increase the fee component in our POP contracts.

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 recent decline in commodity prices has resulted in a decrease in our common unit price, which is expected to increase our debt and equity financing costs. While lower commodity prices and industry uncertainty may result in increased financing costs, we believe we have sufficient access to the financial resources and liquidity necessary to meet our requirements for working capital, debt service payments and capital expenditures.

During 2014, we utilized cash from operations, our commercial paper program and proceeds from our equity issuances, including our May 2014 equity offering and our "at-the-market" equity program, to fund our short-term liquidity needs and capital projects. See discussion under "Short-term Liquidity" and "Long-term Financing" for more information.

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

	December 31,	
	2014	**2013**
Long-term debt	**50%**	55%
Equity	**50%**	45%
Debt (including notes payable)	**54%**	55%
Equity	**46%**	45%

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 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. To the extent commercial paper is unavailable, the Partnership Credit Agreement may be used.

The total amount of short-term borrowings authorized by our general partner's Board of Directors is $2.5 billion. At December 31, 2014, we had $1.1 billion of commercial paper outstanding, $14 million of letters of credit issued and no borrowings outstanding under our Partnership Credit Agreement. At December 31, 2014, we had approximately $42.5 million of cash and cash equivalents and approximately $630.7 million of credit available under the Partnership Credit Agreement. As of December 31, 2014, we could have issued $3.3 billion of short- and long-term debt to meet our liquidity needs under the most restrictive provisions contained in our various borrowing agreements.

The weighted-average interest rate at December 31, 2014, on our short-term borrowings was 0.54 percent. Based on the forward LIBOR curve, we expect the interest rates on our short-term borrowings to increase in 2015, compared with interest rates on amounts outstanding at December 31, 2014.

Our Partnership Credit Agreement, which was amended and restated effective on January 31, 2014, and expires in January 2019, is a $1.7 billion revolving credit facility and includes a $100 million sublimit for the issuance of standby letters of credit, a $150 million swingline sublimit and an option to request an increase in the size of the facility to an aggregate of $2.4 billion by either commitments from new lenders or increased commitments from existing lenders. Our Partnership Credit Agreement is available for general partnership purposes. During the second quarter 2014, we increased the size of our commercial paper program to $1.7 billion from $1.2 billion. In addition, in February 2015, we notified our lenders of our intent to exercise our option to increase the capacity of the facility to an aggregate of $2.4 billion by increased commitments from existing lenders and/or commitments from one or more new lenders, which is pending lenders' approval. 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 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, 2014, our ratio of indebtedness to adjusted EBITDA was 3.7 to 1, and we were in compliance with all covenants under our Partnership Credit Agreement.

Financing for the West Texas LPG acquisition came from available cash on hand and borrowings under our existing $1.7 billion commercial paper program. See additional discussion of this acquisition in the "Financial Results and Operating Information" section in our Natural Gas Liquids segment.

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.

Long-term Financing - In addition to our principal sources of short-term liquidity discussed above, we expect to fund our longer-term cash 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 and 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, or pursuing other debt or equity financing alternatives. Some of these alternatives could involve higher costs or negatively affect our credit ratings, among other factors. Based on our investment-grade credit ratings, general financial condition and market expectations regarding our future earnings and projected cash flows, we believe that we will be able to meet our cash requirements and maintain our investment-grade credit ratings.

<u>Debt Issuances</u> - 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.

In September 2012, we completed an underwritten public offering of $1.3 billion of senior notes, consisting of $400 million, 2.0 percent senior notes due 2017 and $900 million, 3.375 percent senior notes due 2022. A portion of the net proceeds from the offering of approximately $1.29 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.

<u>Equity Issuances</u> - In May 2014, we completed an underwritten public offering of approximately 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 outstanding, fund our capital expenditures and for general partnership purposes.

We have an "at-the-market" equity program for the offer and sale from time to time of our common units. In November 2014, we entered into an equity distribution agreement in the 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. During 2014, we utilized the remainder of our previous equity distribution agreement in the aggregate amount of $300 million. At December 31, 2014, we had approximately $514 million of registered common units available for issuance under our "at-the-market" equity program.

During the three months ended December 31, 2014, we sold approximately 3.5 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 $158.7 million. Net cash proceeds, after deducting agent commissions and other related costs, were approximately $156.7 million, which were used for general partnership purposes.

During the year ended December 31, 2014, we sold approximately 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.

As a result of these transactions, ONEOK's aggregate ownership interest in us decreased to 37.8 percent at December 31, 2014, from 41.2 percent at December 31, 2013.

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 three months ended December 31, 2013, we sold approximately 471 thousand 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 $19.9 million. Net cash proceeds, after deducting agent commissions and other related costs, were approximately $19.9 million, which were used for general partnership purposes.

During the year ended December 31, 2013, we sold approximately 681 thousand 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.

In March 2012, we completed an underwritten public offering of 8.0 million common units at a public offering price of $59.27 per common unit, generating net proceeds of approximately $460 million. We also sold 8.0 million common units to ONEOK in a private placement, generating net proceeds of approximately $460 million. In conjunction with the issuances, ONEOK Partners GP contributed approximately $19 million in order to maintain its 2 percent general partner interest in us. We used the net proceeds from the issuances to repay $295 million of borrowings under our commercial paper program, to repay amounts on the maturity of our $350 million, 5.9 percent senior notes due in April 2012 and for other general partnership purposes, including capital expenditures.

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. At December 31, 2014, we had forward-starting interest-rate swaps with notional amounts totaling $900 million that were designated as cash flow hedges of which $400 million have settlement dates of more than 12 months and $500 million have settlement dates of less than 12 months.

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 $1.7 billion, $1.9 billion and $1.6 billion for 2014, 2013 and 2012, respectively. Capital expenditures in 2014 were less than 2013 capital expenditures due primarily to the timing of expenditures on growth projects in our Natural Gas Gathering and Processing and Natural Gas Liquids segments. Capital expenditures increased for 2013, compared with 2012, due primarily to 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	2014	2013	2012
		(*Millions of dollars*)	
Natural Gas Gathering and Processing	**$ 858.0**	$ 747.6	$ 544.7
Natural Gas Liquids	**751.4**	1,087.8	912.4
Natural Gas Pipelines	**9.7**	11.4	1.2
Total growth capital expenditures	**$ 1,619.1**	$ 1,846.8	$ 1,458.3

Maintenance Capital Expenditures	2014	2013	2012
		(*Millions of dollars*)	
Natural Gas Gathering and Processing	**$ 40.9**	$ 26.8	$ 21.4
Natural Gas Liquids	**46.6**	40.5	56.1
Natural Gas Pipelines	**33.3**	23.3	24.2
Other	**6.1**	1.9	0.5
Total maintenance capital expenditures	**$ 126.9**	$ 92.5	$ 102.2

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 for $305 million 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. 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 2015 projected growth and maintenance capital expenditures, excluding AFUDC:

2015 Projected Capital Expenditures	Growth	Maintenance	Total
		(*Millions of dollars*)	
Natural Gas Gathering and Processing	$ 721	$ 40	$ 761
Natural Gas Liquids	253	58	311
Natural Gas Pipelines	111	28	139
Other	—	16	16
Total projected capital expenditures	$ 1,085	$ 142	$ 1,227

Projected 2015 capital expenditures are lower than 2014 capital expenditures due to suspending certain growth capital expenditures as discussed in “Growth Projects” in the Natural Gas Gathering and Processing and Natural Gas Liquids segments in Financial Results and Operating Information. We have approximately $2.1 billion to $3.0 billion of projects in various stages of construction, including approximately $2.2 billion in new projects and acquisitions announced in 2014. We expect to continue to finance future capital expenditures with a combination of operating cash flows, short- and long-term debt and the issuance of common units.

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.

West Texas LPG Pipeline - The limited partnership agreement of West Texas LPG Pipeline Limited Partnership (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 for a calendar quarter are currently declared and paid by WTLPG in the next succeeding 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 January 16, 2015, are shown in the table below:

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

Our commercial paper program is rated Prime-2 by Moody's and A-2 by S&P. Our credit ratings, which are currently 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.

In February 2014, S&P affirmed our current rating and revised its outlook to stable. However, recent declines in the energy commodity price environment and potential adverse impacts 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 2019. An adverse 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. There were no financial derivative instruments with contingent features related to credit risk that were in a net liability position at December 31, 2014.

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.

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

	Years Ended December 31,		
	2014	**2013**	**2012**
		(Millions of dollars)	
Common unitholders	**$ 506.5**	$ 430.4	$ 370.5
Class B unitholders	**219.7**	209.5	189.0
General partner	**326.0**	269.8	201.4
Noncontrolling interests	**0.5**	0.6	0.8
Total cash distributions paid	**$ 1,052.7**	$ 910.3	$ 761.7

For the years ended December 31, 2014, 2013 and 2012, cash distributions paid to our general partner included incentive distributions of $305.0 million, $251.7 million and $186.1 million, respectively.

In January 2015, our general partner declared a cash distribution of $0.79 per unit ($3.16 per unit on an annualized basis) for the fourth quarter 2014, which was paid on February 13, 2015, to unitholders of record as of January 31, 2015.

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.

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 recent decline in commodity prices has contributed to a decrease in our unit price. While lower commodity prices and industry uncertainty may increase debt and equity financing costs, we expect to have sufficient liquidity to finance our announced capital growth projects. 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 impact 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 earnings from investments, distributions received from unconsolidated affiliates 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,		
	2014	**2013**	**2012**
		(Millions of dollars)	
Total cash provided by (used in):			
Operating activities	**$ 1,309.8**	$ 1,007.7	$ 946.1
Investing activities	**(2,533.0)**	(2,326.1)	(1,545.2)
Financing activities	**1,131.2**	915.8	1,101.1
Change in cash and cash equivalents	**(92.0)**	(402.6)	502.0
Cash and cash equivalents at beginning of period	**134.5**	537.1	35.1
Cash and cash equivalents at end of period	**$ 42.5**	$ 134.5	$ 537.1

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 competition from other service providers, could affect our earnings and operating cash flows.

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 net margin 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.

2013 vs. 2012 - Cash flows from operating activities, before changes in operating assets and liabilities, were $1.0 billion for 2013, compared with $1.1 billion for 2012. The decrease was due primarily to an increase in operating costs and interest expense as discussed in "Financial Results and Operating Information." Distributions received from unconsolidated affiliates also decreased due to lower equity earnings.

The changes in operating assets and liabilities increased operating cash flows $8.1 million for 2013, compared with a decrease of $129.3 million for 2012. This change is due primarily to the settlement of our interest-rate swaps associated with our $1.3 billion debt issuance in September 2012, 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 NGL volumes in storage and commodity imbalances.

Investing Cash Flows - 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.

Cash used in investing activities increased for 2013, compared with 2012, due primarily to increased capital expenditures on our growth projects in our Natural Gas Gathering and Processing, and Natural Gas Liquids segments, as well as expenditures for the Sage Creek acquisition and the remaining 30 percent interest in the Maysville, Oklahoma, natural gas processing facility.

Financing Cash Flows - Cash provided by financing activities increased for 2014, compared with 2013, due primarily to proceeds from the borrowing of notes payable 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.

Cash provided by financing activities decreased for 2013, compared with 2012, due primarily to higher distributions paid. During 2013, we issued long-term debt generating net proceeds totaling approximately $1.24 billion and common units generating net proceeds totaling approximately $596.2 million, including our general partner's contribution to maintain its 2 percent general partner interest. During 2012, cash flows provided by financing activities reflects the issuance of long-term debt generating net proceeds totaling approximately $1.29 billion, the issuance of common units generating net proceeds totaling approximately $938.5 million, including our general partner's contribution to maintain its 2 percent general partner interest, and the repayment of long-term debt totaling approximately $361.1 million.

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 - 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 as of July 1. Our goodwill impairment analysis performed as of July 1, 2014, did not result in an impairment charge nor did our analysis reflect any reporting units at risk, and subsequent to that date, no event has occurred indicating that the implied fair value of each of our reporting units (including its implied goodwill) is less than the carrying value of its net assets. There were also no impairment charges resulting from our 2013 or 2012 impairment tests.

As part of our goodwill impairment test, we 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, 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, 2014	December 31, 2013
	(*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. We determined that there were no asset impairments in 2014, 2013 or 2012.

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. We determined that there were no impairments to our investments in unconsolidated affiliates in 2013 or 2012.

Historically, low natural gas prices and the relatively higher crude oil and NGL prices compared with natural gas on a heating-value basis have caused producers primarily to focus development efforts on crude oil and NGL-rich supply basins rather than areas with dry natural gas production, such as coal-bed methane areas in the Powder River Basin. The reduced coal-bed methane development activities and natural production declines in the dry natural gas formations of the Powder River Basin have resulted in lower natural gas volumes available to be gathered. While the reserve potential in the dry natural gas formations of the Powder River Basin still exists, future drilling and development in this area will be affected by commodity prices and producers' alternative prospects.

During 2014, the volumes gathered on the Bighorn Gas Gathering system, in which we own a 49 percent equity interest and which operates in the coal-bed methane area of the Powder River Basin, declined at a rate greater than in prior periods and greater than expected. Due to these additional declines in volumes, Bighorn Gas Gathering recorded an impairment of its underlying assets in September 2014, when the operator determined that the volume decline would be sustained for the foreseeable future. As a result of these developments, we reviewed our equity method investment in Bighorn Gas Gathering for impairment and recorded noncash impairment charges totaling $76.4 million related to Bighorn Gas Gathering. The noncash impairment charges are included in equity earnings from investments in our accompanying Consolidated Statements of Income. The net book value of our equity method investment in Bighorn Gas Gathering is $7.9 million at December 31, 2014, and no equity method goodwill remains. We determined there were no impairments to investments in unconsolidated affiliates in 2013 or 2012.

A continued decline in volumes gathered in the coal-bed methane area of the Powder River Basin may reduce our ability to recover the carrying value of our equity investments in this area and could result in additional noncash charges to earnings. The net book value of our remaining equity method investments in this dry natural gas area is $206.0 million, which includes $130.5 million of equity method goodwill. We expect the energy commodity price environment to remain depressed for at least the near term, which has caused producers to announce plans for reduced drilling for crude oil and natural gas, which we expect will slow volume growth or reduce volumes of natural gas delivered to systems owned by our equity method investments.

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 2014, 2013 or 2012. 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, 2014. 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**	**2015**	**2016**	**2017**	**2018**	**2019**	**Thereafter**
	(*Millions of dollars*)						
ONEOK Partners senior notes	$ 6,000.0	$ —	$ 1,100.0	$ 400.0	$ 425.0	$ 500.0	$ 3,575.0
Guardian Pipeline senior notes	59.6	7.7	7.7	7.7	7.7	7.7	21.1
Interest payments on debt	4,306.9	315.2	278.4	263.2	252.6	206.5	2,991.0
Notes payable	1,055.3	1,055.3	—	—	—	—	—
Operating leases	2.8	0.6	0.4	0.3	0.3	0.2	1.0
Firm transportation and storage contracts	222.8	33.6	32.1	30.4	29.4	28.8	68.5
Financial and physical derivatives	23.5	23.5	—	—	—	—	—
Purchase commitments, rights of way and other	441.6	78.2	78.3	78.0	78.0	37.0	92.1
Total	$ 12,112.5	$ 1,514.1	$ 1,496.9	$ 779.6	$ 793.0	$ 780.2	$ 6,748.7

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

<u>Interest payments on debt</u> - Interest expense is calculated by multiplying long-term debt principle amount by the respective coupon rates.

<u>Operating leases</u> - Our operating leases include leases for office space, pipeline equipment and vehicles.

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

<u>Financial and physical derivatives</u> - 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, 2014. 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.

<u>Purchase commitments, rights of way and other</u> - 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 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 the 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 control 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 and 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

In our Natural Gas Gathering and Processing segment, we are exposed to commodity price risk as a result of receiving commodities in exchange for services associated with our POP 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 minimize the impact of near-term price fluctuations related to natural gas, NGLs and condensate.

As of December 31, 2014, we had $53.2 million of commodity-related derivative assets and $1.2 million of commodity-related derivative liabilities, excluding the impact of netting.

The following table sets forth our Natural Gas Gathering and Processing segment's hedging information for the period indicated:

	Year Ending December 31, 2015		
	Volumes Hedged	**Average Price**	**Percentage Hedged**
NGLs (*MBbl/d*)	6.4	$ 0.59 / gallon	33%
Condensate (*MBbl/d*)	1.9	$ 1.31 / gallon	44%
Total (*MBbl/d*)	8.3	$ 0.76 / gallon	35%
Natural gas (*BBtu/d*)	112.8	$ 4.03 / MMBtu	80%

We expect our natural gas liquids and natural gas commodity price sensitivity within this segment to increase in the future as our capital projects are completed and volumes increase under POP contracts with our customers. 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, 2014, 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:

- a $0.01 per-gallon change in the composite price of NGLs would change 12-month forward net margin by approximately $3.0 million;
- a $1.00 per-barrel change in the price of crude oil would change 12-month forward net margin by approximately $1.6 million; and
- a $0.10 per-MMBtu change in the price of residue natural gas would change 12-month forward net margin by approximately $5.2 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 margins for certain contracts.

In our Natural Gas Liquids segment, we are exposed to basis 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 to reduce the impact of price fluctuations related to NGLs. At December 31, 2014 and 2013, there were no financial derivative instruments with respect to our natural gas liquids operations.

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, 2014 and 2013, 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 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, 2014 and 2013, we had forward-starting interest-rate swaps with notional amounts totaling $900 million and $400 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, 2014, we had derivative assets of $2.3 million and derivative liabilities of $44.8 million related to these interest-rate swaps. At December 31, 2013, we had derivative assets of $54.5 million related to these interest-rate swaps.

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. We are not exposed to material credit risk with exploration and production customers under POP contracts in our Natural Gas Gathering and Processing segment due to the nature of the POP contracts whereby we receive proceeds from the sale of commodities and remit a portion of those proceeds back to the producers. 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 storage activities may be impacted by the depressed commodity price environment and could experience financial problems. The majority of our Natural Gas Liquids segment's and Natural Gas Pipeline segment's pipeline tariffs provide us the ability to require security from shippers. Our remaining customers are primarily large local distribution, power generation and petrochemical companies.

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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, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, 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, 2014, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. 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 24, 2015

ONEOK Partners, L.P. and Subsidiaries
CONSOLIDATED STATEMENTS OF INCOME

	Years Ended December 31,		
	2014	**2013**	**2012**
	(*Thousands of dollars, except per unit amounts*)		
Revenues			
Commodity sales	**$ 10,724,981**	$ 10,549,157	$ 9,010,151
Services	**1,466,684**	1,320,116	1,172,000
Total revenues	**12,191,665**	11,869,273	10,182,151
Cost of sales and fuel	**10,088,548**	10,222,213	8,540,319
Net margin	**2,103,117**	1,647,060	1,641,832
Operating expenses			
Operations and maintenance	**599,076**	464,633	433,063
Depreciation and amortization	**291,236**	236,743	203,101
General taxes	**70,581**	56,880	49,477
Total operating expenses	**960,893**	758,256	685,641
Gain (loss) on sale of assets	**6,599**	11,881	6,736
Operating income	**1,148,823**	900,685	962,927
Equity earnings from investments (Note M)	**41,003**	110,517	123,024
Allowance for equity funds used during construction	**14,937**	30,522	13,648
Other income	**5,447**	12,870	7,577
Other expense	**(4,299)**	(3,039)	(2,625)
Interest expense (net of capitalized interest of $54,813, $56,506 and $40,482, respectively)	**(281,908)**	(236,714)	(206,018)
Income before income taxes	**924,003**	814,841	898,533
Income taxes (Note L)	**(12,668)**	(10,858)	(10,105)
Net income	**911,335**	803,983	888,428
Less: Net income attributable to noncontrolling interests	**1,037**	357	438
Net income attributable to ONEOK Partners, L.P.	**$ 910,298**	$ 803,626	$ 887,990
Limited partners' interest in net income:			
Net income attributable to ONEOK Partners, L.P.	**$ 910,298**	$ 803,626	$ 887,990
General partner's interest in net income	**(344,241)**	(275,539)	(227,855)
Limited partners' interest in net income	**$ 566,057**	$ 528,087	$ 660,135
Limited partners' net income per unit, basic and diluted (Note K)	**$ 2.33**	$ 2.35	$ 3.04
Number of units used in computation (*thousands*)	**243,306**	224,658	217,134

See accompanying Notes to Consolidated Financial Statements.

ONEOK Partners, L.P. and Subsidiaries
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31,		
	2014	**2013**	**2012**
	(*Thousands of dollars*)		
Net income	**$ 911,335**	$ 803,983	$ 888,428
Other comprehensive income (loss)			
Unrealized gains (losses) on derivatives	**(64,639)**	32,141	10,295
Realized (gains) losses on derivatives recognized in net income	**31,653**	8,344	(58,529)
Total other comprehensive income (loss)	**(32,986)**	40,485	(48,234)
Comprehensive income	**878,349**	844,468	840,194
Less: Comprehensive income attributable to noncontrolling interests	**1,037**	357	438
Comprehensive income attributable to ONEOK Partners, L.P.	**$ 877,312**	$ 844,111	$ 839,756

See accompanying Notes to Consolidated Financial Statements.

ONEOK Partners, L.P. and Subsidiaries
CONSOLIDATED BALANCE SHEETS

	December 31, 2014	December 31, 2013
Assets	(*Thousands of dollars*)	
Current assets		
Cash and cash equivalents	**$ 42,530**	$ 134,530
Accounts receivable, net	**735,830**	1,103,130
Affiliate receivables	**8,553**	9,185
Natural gas and natural gas liquids in storage	**134,134**	188,286
Commodity imbalances	**64,788**	80,481
Materials and supplies	**55,833**	54,112
Other current assets	**44,385**	13,379
Total current assets	**1,086,053**	1,583,103
Property, plant and equipment		
Property, plant and equipment	**13,377,617**	10,755,048
Accumulated depreciation and amortization	**1,842,084**	1,652,648
Net property, plant and equipment (Note E)	**11,535,533**	9,102,400
Investments and other assets		
Investments in unconsolidated affiliates (Note M)	**1,132,653**	1,229,838
Goodwill and intangible assets (Note F)	**822,358**	832,180
Other assets	**57,950**	115,087
Total investments and other assets	**2,012,961**	2,177,105
Total assets	**$ 14,634,547**	$ 12,862,608
Liabilities and equity		
Current liabilities		
Current maturities of long-term debt (Note H)	**$ 7,650**	$ 7,650
Notes payable (Note G)	**1,055,296**	—
Accounts payable	**874,692**	1,255,411
Affiliate payables	**36,106**	47,458
Commodity imbalances	**104,650**	213,577
Accrued interest	**91,990**	92,711
Other current liabilities	**165,672**	89,211
Total current liabilities	**2,336,056**	1,706,018
Long-term debt, excluding current maturities (Note H)	**6,038,379**	6,044,867
Deferred credits and other liabilities	**141,337**	113,027
Commitments and contingencies (Note O)		
Equity		
ONEOK Partners, L.P. partners' equity (Note I):		
General partner	**211,914**	170,561
Common units: 180,826,973 and 159,007,854 units issued and outstanding at December 31, 2014 and December 31, 2013, respectively	**4,456,372**	3,459,920
Class B units: 72,988,252 units issued and outstanding at December 31, 2014 and December 31, 2013	**1,374,375**	1,422,516
Accumulated other comprehensive loss (Note J)	**(91,823)**	(58,837)
Total ONEOK Partners, L.P. partners' equity	**5,950,838**	4,994,160
Noncontrolling interests in consolidated subsidiaries	**167,937**	4,536
Total equity	**6,118,775**	4,998,696
Total liabilities and equity	**$ 14,634,547**	$ 12,862,608

See accompanying Notes to Consolidated Financial Statements.

ONEOK Partners, L.P. and Subsidiaries
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2014	2013	2012
	(Thousands of dollars)		
Operating activities			
Net income	**$ 911,335**	$ 803,983	$ 888,428
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	**291,236**	236,743	203,101
Allowance for equity funds used during construction	**(14,937)**	(30,522)	(13,648)
Loss (gain) on sale of assets	**(6,599)**	(11,881)	(6,736)
Deferred income taxes	**10,832**	5,444	6,815
Equity earnings from investments	**(41,003)**	(110,517)	(123,024)
Distributions received from unconsolidated affiliates	**117,912**	106,364	120,442
Changes in assets and liabilities, net of acquisitions:			
Accounts receivable	**373,459**	(184,271)	8,201
Affiliate receivables	**632**	6,907	(11,960)
Natural gas and natural gas liquids in storage	**54,152**	47,550	(33,650)
Accounts payable	**(351,470)**	187,253	(45,014)
Affiliate payables	**(11,352)**	(28,252)	34,614
Commodity imbalances, net	**(93,234)**	(50,373)	43,811
Accrued interest	**(721)**	15,977	6,350
Other assets and liabilities, net	**69,578**	13,326	(131,677)
Cash provided by operating activities	**1,309,820**	1,007,731	946,053
Investing activities			
Capital expenditures (less allowance for equity funds used during construction)	**(1,745,990)**	(1,939,326)	(1,560,513)
Cash paid for acquisitions, net of cash received	**(814,934)**	(394,889)	—
Contributions to unconsolidated affiliates	**(1,063)**	(35,308)	(30,768)
Distributions received from unconsolidated affiliates	**21,107**	31,134	35,299
Proceeds from sale of assets	**7,817**	12,290	10,778
Cash used in investing activities	**(2,533,063)**	(2,326,099)	(1,545,204)
Financing activities			
Cash distributions:			
General and limited partners	**(1,052,245)**	(909,713)	(760,912)
Noncontrolling interests	**(549)**	(588)	(783)
Borrowing (repayment) of notes payable, net	**1,055,296**	—	—
Issuance of long-term debt, net of discounts	**—**	1,247,822	1,295,036
Long-term debt financing costs	**—**	(10,246)	(9,641)
Repayment of long-term debt	**(7,650)**	(7,650)	(361,062)
Issuance of common units, net of issuance costs	**1,113,139**	583,929	919,427
Contribution from general partner	**23,252**	12,270	19,069
Cash provided by financing activities	**1,131,243**	915,824	1,101,134
Change in cash and cash equivalents	**(92,000)**	(402,544)	501,983
Cash and cash equivalents at beginning of period	**134,530**	537,074	35,091
Cash and cash equivalents at end of period	**$ 42,530**	$ 134,530	$ 537,074
Supplemental cash flow information:			
Cash paid for interest, net of amounts capitalized	**$ 271,314**	$ 203,072	$ 317,044
Cash paid for income taxes	**$ 1,336**	$ 3,435	$ 7,542

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, 2012	130,827,354	72,988,252	$ 106,936	$ 1,959,437
Net income	—	—	227,855	436,710
Other comprehensive income (loss)	—	—	—	—
Issuance of common units (Note I)	16,000,000	—	—	919,427
Contribution from general partner (Note I)	—	—	19,069	—
Distributions paid (Note I)	—	—	(201,347)	(370,523)
December 31, 2012	146,827,354	72,988,252	152,513	2,945,051
Net income	—	—	275,539	356,593
Other comprehensive income (loss) (Note J)	—	—	—	—
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**

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, 2012	$ 1,426,115	$ (51,088)	$ 5,112	$ 3,446,512
Net income	223,425	—	438	888,428
Other comprehensive income (loss)	—	(48,234)	—	(48,234)
Issuance of common units (Note I)	—	—	—	919,427
Contribution from general partner (Note I)	—	—	—	19,069
Distributions paid (Note I)	(189,042)	—	(783)	(761,695)
December 31, 2012	1,460,498	(99,322)	4,767	4,463,507
Net income	171,494	—	357	803,983
Other comprehensive income (loss) (Note J)	—	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**

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 37.8 percent aggregate equity interest in us at December 31, 2014.

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, Stack, SCOOP, Springer Shale and 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. Some of the natural gas we gather from the Powder River Basin of Wyoming is coal-bed methane, or dry natural gas, that does not require processing or NGL extraction in order to be marketable; dry natural gas is gathered, compressed and delivered into a downstream pipeline or marketed for a fee.

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 FERC-regulated interstate natural gas pipeline assets transport natural gas through gas pipelines in North Dakota, Minnesota, Wisconsin, Illinois, Indiana, Kentucky, Tennessee, Oklahoma, Texas and New Mexico. Our interstate pipeline companies include Midwestern Gas Transmission, Viking Gas Transmission, Guardian Pipeline, OkTex Pipeline and Northern Border Pipeline of which we have a 50 percent interest.

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 areas. We also have access to the major natural gas producing areas, including the Mississippian Lime formation, in south central Kansas. In Texas, our intrastate natural gas pipelines are connected to the major natural gas producing areas in the Texas panhandle, including the Granite Wash formation and Delaware and Cline producing formations in the Permian Basin, and transport natural gas throughout the western portion of Texas, including the Waha Hub where other pipelines may be accessed for transportation to western markets, the Houston Ship Channel market to the east and the Mid-Continent market to the north.

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 groups 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 and LIBOR and other liquid money-market instrument rates. We also utilize internally developed basis curves that incorporate observable and unobservable market data. 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.

Fair Value Hierarchy - 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 basis curves that incorporate observable and unobservable market data, NGL price curves from broker quotes, 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 is not 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 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 Liquids segment and Natural Gas Pipelines segment are recognized based upon contracted capacity and contracted volumes transported and stored under service agreements in the period services are provided.

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, 2014 and 2013, 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 sales 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 cash flow. We formally document all relationships between hedging instruments and hedged items, as well as risk-management objectives, 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 as of July 1. Our goodwill impairment analysis performed as of July 1, 2014, did not result in an impairment charge nor did our analysis reflect any reporting units at risk, and subsequent to that date, no event has occurred indicating that the implied fair value of each of our reporting units (including its inherent goodwill) is less than the carrying value of its net assets. There were also no impairment charges resulting from our 2013 or 2012 impairment tests.

As part of our impairment test, we 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, 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. We determined that there were no asset impairments in 2014, 2013 or 2012.

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 unconsolidated affiliates disclosures.

Regulation - Our intrastate natural gas transmission 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, 2014 and 2013, we recorded regulatory assets of approximately $6.1 million and $6.8 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. Except for the regulated companies, 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 2014, 2013 and 2012, 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 and Canada 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 2014, 2013 and 2012. 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 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 will adopt this guidance in the first quarter 2016, and we are evaluating the impact on us.

In November 2014, the FASB issued ASU 2014-17, "Business Combination (Topic 805): Pushdown Accounting," which provides an acquired entity with an option to apply pushdown accounting in its separate financial statements when a change-in-control event occurs. An acquired entity may elect the option to apply pushdown accounting in the reporting period in which the change-in-control event occurs. The standard applies to all entities and was effective on November 18, 2014. We adopted this guidance beginning in the fourth quarter 2014, and we do not expect it to materially impact us.

In August 2014, the FASB issued ASU 2014-15, "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 will adopt this guidance beginning in the first 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," 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. This update will be effective for interim and annual periods that begin on or after December 15, 2016, with either retrospective application for all periods presented or retrospective application with a cumulative effect adjustment. We will adopt this guidance beginning in the first quarter 2017, and we are evaluating the impact on us.

In April 2014, the FASB issued ASU 2014-08, "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. This guidance will be effective for interim and annual periods for all assets that are disposed of or classified as being held for sale in fiscal years that begin on or after December 15, 2014. We will adopt this guidance beginning in the first quarter 2015, and it could impact us in the future if we dispose of any individually significant components.

B. ACQUISITIONS

West Texas LPG Acquisition - In November 2014, we completed the acquisition of an 80 percent interest in the West Texas LPG Pipeline Limited Partnership (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 $1.7 billion 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 are expected to provide us 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, 2014, reflects the preliminary purchase price allocation based on available information and is subject to customary working capital adjustments. We are reviewing the valuation to determine the final purchase price allocation. The preliminary purchase price allocation and assessment of the fair value of the assets acquired as of the acquisition date were as follows (in thousands):

Cash	$	13,839
Accounts receivable		9,132
Other current assets		3,369
Property, plant and equipment		
Regulated		807,601
Nonregulated		153,919
Total property, plant and equipment		961,520
Total fair value of assets acquired		987,860
Accounts payable		(8,621)
Other current liabilities		(1,553)
Total fair value of liabilities acquired		(10,174)
Less: fair value of noncontrolling interest		(162,913)
Net assets acquired		814,773
Less: cash received		(13,839)
Net cash paid for acquisition	$	800,934

We consolidate West Texas LPG as we control the system. Beginning November 29, 2014, the results of operations for West Texas LPG are included in our Natural Gas Liquids segment. We have recorded noncontrolling interests in consolidated subsidiaries on our Consolidated Statements of Income and Consolidated Balance Sheets to recognize the portion of West Texas LPG that we do not own. The portion of the assets and liabilities of West Texas LPG acquired attributable to noncontrolling interests was accounted for as noncash activity. The fair value of the noncontrolling interest of West Texas LPG was estimated by applying a market approach.

Revenues and earnings related to West Texas LPG have been included within the Consolidated Statement 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 for a calendar quarter are currently declared and paid by WTLPG in the next succeeding 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 a region where producers are actively drilling for crude oil and NGL-rich natural gas.

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, 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 posted no cash collateral.
(b) - Included in other current assets, other assets or other current liabilities in our Consolidated Balance Sheets.

	December 31, 2013					
	Level 1	Level 2	Level 3	Total - Gross	Netting (a)	Total - Net (b)
	(*Thousands of dollars*)					
Derivative assets						
Commodity contracts						
Financial contracts	$ —	$ 3,657	$ 2,812	$ 6,469	$ (1,746)	$ 4,723
Physical contracts	—	—	2,023	2,023	(946)	1,077
Interest-rate contracts	—	54,503	—	54,503	—	54,503
Total derivative assets	$ —	$ 58,160	$ 4,835	$ 62,995	$ (2,692)	$ 60,303
Derivative liabilities						
Commodity contracts						
Financial contracts	$ —	$ (2,953)	$ (2,154)	$ (5,107)	$ 1,746	$ (3,361)
Physical contracts	—	—	(3,463)	(3,463)	946	(2,517)
Total derivative liabilities	$ —	$ (2,953)	$ (5,617)	$ (8,570)	$ 2,692	$ (5,878)

(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, 2013, we had no cash collateral held or 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:

Derivative Assets (Liabilities)	Years Ended December 31, 2014	2013
	(*Thousands of dollars*)	
Net assets (liabilities) at beginning of period	**$ (782)**	$ (2,423)
Total realized/unrealized gains (losses):		
Included in earnings (a)	**(927)**	959
Included in other comprehensive income (loss)	**7,260**	682
Purchases, issuances and settlements	**3,734**	—
Net assets (liabilities) at end of period	**$ 9,285**	$ (782)
Total gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to assets and liabilities still held as of the end of the period (a)	**$ 31**	$ 959

(a) - Included in commodity sales revenues in our Consolidated Statements of Income.

During the years ended December 31, 2014 and 2013, there were no transfers between levels.

Other Financial Instruments - The approximate fair value of cash and cash equivalents, accounts receivable, accounts payable and notes payable 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 notes payable are classified as Level 2 since the estimated fair value of the notes payable can be determined using information available in the commercial paper market.

The estimated fair value of the aggregate of our long-term debt outstanding, including current maturities, was $6.4 billion and $6.5 billion at December 31, 2014 and 2013, respectively. The book value of the aggregate of our long-term debt outstanding, including current maturities, was $6.0 billion and $6.1 billion at December 31, 2014 and 2013, respectively. The estimated fair value of the aggregate of our long-term debt 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 2014, we recorded a noncash impairment to our equity investment in Bighorn Gas Gathering. The valuation of this investment required use of significant unobservable inputs. We used an income approach to estimate the fair value of our investment. 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 this investment is classified as Level 3. See Note M for additional information about our investment in Bighorn Gas Gathering and the impairment charge.

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 sales and financial derivatives to secure a certain price for a portion of our natural gas, condensate and NGL products. 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 in exchange for services associated with our POP contracts. We are also 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 basis 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 to reduce the impact of price fluctuations related to NGLs. At December 31, 2014 and 2013, there were no financial derivative instruments with respect to our natural gas liquids operations.

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, 2014 and 2013, 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, 2014 and 2013, we had forward-starting interest-rate swaps with notional amounts totaling $900 million and $400 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. At December 31, 2014, notional amounts totaling $400 million have settlement dates greater than 12 months.

Fair Values of Derivative Instruments - See Note A for a discussion of the inputs associated with our fair value measurements. The following table sets forth the fair values of our derivative instruments for the periods indicated:

	December 31, 2014		December 31, 2013	
	Assets (a)	**(Liabilities) (a)**	**Assets (a)**	**(Liabilities) (a)**
		(Thousands of dollars)		
Derivatives designated as hedging instruments				
Commodity contracts				
Financial contracts	**$ 43,234**	**$ (1,137)**	$ 6,469	$ (5,107)
Physical contracts	**9,922**	**—**	1,064	(3,463)
Interest-rate contracts	**2,288**	**(44,843)**	54,503	—
Total derivatives designated as hedging instruments	**55,444**	**(45,980)**	62,036	(8,570)
Derivatives not designated as hedging instruments				
Commodity contracts				
Physical contracts	**—**	**(23)**	959	—
Total derivatives not designated as hedging instruments	**—**	**(23)**	959	—
Total derivatives	**$ 55,444**	**$ (46,003)**	$ 62,995	$ (8,570)

(a) - Included on a net basis in other current assets, other assets or other current liabilities on 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:

	Contract Type	December 31, 2014 Purchased/ Payor	December 31, 2014 Sold/ Receiver	December 31, 2013 Purchased/ Payor	December 31, 2013 Sold/ Receiver
Derivatives designated as hedging instruments:					
Cash flow hedges					
Fixed price					
-Natural gas (*Bcf*)	Futures and swaps	—	**(41.2)**	—	(48.1)
-Crude oil and NGLs (*MMBbl*)	Futures, forwards and swaps	—	**(0.5)**	—	(4.0)
Basis					
-Natural gas (*Bcf*)	Futures and swaps	—	**(41.2)**	—	(48.1)
Interest-rate contracts (*Millions of dollars*)	Forward-starting swaps	**$ 900.0**	**$ —**	$ 400.0	$ —

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, 2014, our Consolidated Balance Sheet reflected a net unrealized loss of $91.8 million in accumulated other comprehensive loss. The portion of accumulated other comprehensive loss attributable to our commodity derivative financial instruments is a gain of $53.5 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 $99.4 million, which will be recognized over the life of the long-term, fixed-rate debt. We expect that losses of $10.8 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, 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 loss for the periods indicated:

Derivatives in Cash Flow Hedging Relationships	Years Ended December 31, 2014	2013	2012
	(*Thousands of dollars*)		
Commodity contracts	**$ 32,354**	$ (14,475)	$ 46,804
Interest-rate contracts	**(96,993)**	46,616	(36,509)
Total unrealized gain (loss) recognized in other comprehensive loss on derivatives (effective portion)	**$ (64,639)**	$ 32,141	$ 10,295

The following table sets forth the effect of cash flow hedges on our Consolidated Statements of Income for the periods indicated:

Derivatives in Cash Flow Hedging Relationships	Location of Gain (Loss) Reclassified from Accumulated Other Comprehensive Loss into Net Income (Effective Portion)	Years Ended December 31, 2014	2013	2012
		(*Thousands of dollars*)		
Commodity contracts	Commodity sales revenues	**$ (21,052)**	$ 1,689	$ 61,526
Interest-rate contracts	Interest expense	**(10,601)**	(10,033)	(2,997)
Total gain (loss) reclassified from accumulated other comprehensive loss into net income on derivatives (effective portion)		**$ (31,653)**	$ (8,344)	$ 58,529

Ineffectiveness related to our cash flow hedges was not material for the years ended December 31, 2014, 2013 and 2012. 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 2014, 2013 and 2012.

Credit Risk - Prior to March 31, 2014, all of our commodity derivative financial contracts were with our affiliate ONEOK Energy Services Company, a subsidiary of ONEOK. ONEOK Energy Services Company entered into similar commodity derivative financial contracts with third parties at our direction and on our behalf. On March 31, 2014, ONEOK completed the accelerated wind down of ONEOK Energy Services Company. In the first quarter 2014, outstanding commodity derivative positions with third parties entered into by ONEOK Energy Services Company on our behalf were transferred to us. Beginning in the second quarter 2014, we enter into all commodity derivative financial contracts directly with unaffiliated third parties.

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.

Some of our financial derivative instruments 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 that were in a net liability position as of December 31, 2014.

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, 2014, 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, 2014	December 31, 2013
		(*Thousands of dollars*)	
Nonregulated			
Gathering pipelines and related equipment	5 to 40	**$ 2,449,343**	$ 2,173,271
Processing and fractionation and related equipment	3 to 40	**2,880,572**	2,295,983
Storage and related equipment	5 to 54	**478,276**	362,704
Transmission pipelines and related equipment	5 to 54	**518,585**	302,718
General plant and other	2 to 60	**142,276**	116,468
Construction work in process	—	**1,233,808**	1,068,428
Regulated			
Storage and related equipment	5 to 54	**115,799**	135,922
Natural gas transmission pipelines and related equipment	5 to 77	**1,478,035**	1,420,517
Natural gas liquids transmission pipelines and related equipment	5 to 80	**3,822,799**	2,049,461
General plant and other	2 to 53	**63,424**	53,315
Construction work in process	—	**194,700**	776,261
Property, plant and equipment		**13,377,617**	10,755,048
Accumulated depreciation and amortization - nonregulated		**(1,123,261)**	(1,004,614)
Accumulated depreciation and amortization - regulated		**(718,823)**	(648,034)
Net property, plant and equipment		**$ 11,535,533**	$ 9,102,400

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,		
	2014	**2013**	**2012**
Natural Gas Liquids	**2.0%**	2.0%	1.9%
Natural Gas Pipelines	**2.1%**	2.2%	2.2%

We incurred liabilities for construction work in process that had not been paid at December 31, 2014, 2013 and 2012, of $187.2 million, $226.7 million and $216.5 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.

F. GOODWILL AND INTANGIBLE ASSETS

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

	December 31, 2014	December 31, 2013
	(*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

In September 2013 we completed the Sage Creek acquisition which included goodwill of $20 million and $72 million for our Natural Gas Gathering and Processing segment and Natural Gas Liquids segment, respectively. For additional information related to the acquisition, see Note B.

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 2014, 2013 and 2012 was $11.8 million, $8.7 million and $7.7 million, respectively, and the aggregate amortization expense for each of the next five years is estimated to be approximately $11.8 million. The following table reflects the gross carrying amount and accumulated amortization of intangible assets for the periods presented:

	December 31, 2014	December 31, 2013
	(*Thousands of dollars*)	
Gross intangible assets	**$ 411,650**	$ 409,650
Accumulated amortization	**(78,010)**	(66,188)
Net intangible assets	**$ 333,640**	$ 343,462

G. CREDIT FACILITIES AND SHORT-TERM NOTES PAYABLE

Partnership Credit Agreement - The amount of short-term borrowings authorized by our general partner's Board of Directors is $2.5 billion. At December 31, 2014, we had $1.1 billion of commercial paper outstanding, $14.0 million letters of credit issued and no borrowings outstanding under our Partnership Credit Agreement.

Our Partnership Credit Agreement, which was amended and restated effective on January 31, 2014, and expires in January 2019, is a $1.7 billion revolving credit facility and includes a $100 million sublimit for the issuance of standby letters of credit, a $150 million swingline sublimit and an option to request an increase in the size of the facility to an aggregate of $2.4 billion from $1.7 billion by either commitments from new lenders or increased commitments from existing lenders. Our Partnership Credit Agreement is available for general partnership purposes. During the second quarter 2014, we increased the size of our commercial paper program to $1.7 billion from $1.2 billion. In addition, in February 2015, we notified our lenders of our intent to exercise our option to increase the capacity of the facility to an aggregate of $2.4 billion by increased commitments from existing lenders and/or commitments from one or more new lenders, which is pending lenders' approval. 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. Borrowings under our Partnership Credit Agreement are nonrecourse to ONEOK, and ONEOK does not guarantee our debt, commercial paper or other similar commitments.

Our Partnership Credit Agreement contains financial, operational and legal covenants that remained substantially the same with the amendment. 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 of the acquisition 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, 2014, our ratio of indebtedness to adjusted EBITDA was 3.7 to 1, and we were in compliance with all covenants under our Partnership Credit Agreement.

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, 2014	December 31, 2013
	(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
$900,000 at 3.375 % due 2022	**900,000**	900,000
$425,000 at 5.0 % due 2023	**425,000**	425,000
$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
$400,000 at 6.2% due 2043	**400,000**	400,000
Guardian Pipeline		
Average 7.88% due 2022	**59,557**	67,208
Total long-term notes payable	**6,059,557**	6,067,208
Unamortized debt discount and other	**(13,528)**	(14,691)
Current maturities	**(7,650)**	(7,650)
Long-term debt	**$ 6,038,379**	$ 6,044,867

The aggregate maturities of long-term debt outstanding for years 2015 through 2019 are shown below:

	ONEOK Partners	Guardian Pipeline	Total
		(Millions of dollars)	
2015	$ —	$ 7.7	$ 7.7
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

Debt issuance and maturity - 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.

In September 2012, we completed an underwritten public offering of $1.3 billion of senior notes, consisting of $400 million, 2.0 percent senior notes due 2017 and $900 million, 3.375 percent senior notes due 2022. A portion of the net proceeds from the offering of approximately $1.29 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.

We used a portion of the proceeds from our March 2012 equity issuance to repay our $350 million, 5.9 percent senior notes due April 2012.

Debt covenants - 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 senior notes due 2016 (6.15 percent), 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 2016 (3.25 percent) and 2041 at a redemption price equal to the principal amount, plus accrued and unpaid interest, starting one month 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. We may redeem our senior notes due 2018, 2023 and 2043 at par, plus accrued and unpaid interest to the redemption date, starting one month, 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, 2014, 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, 19.8 million common units and the entire 2 percent general partner interest in us, which together constituted a 37.8 percent ownership interest in us at December 31, 2014.

Equity Issuances - In May 2014, we completed an underwritten public offering of approximately 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.

We have an “at-the-market” equity program for the offer and sale from time to time of our common units. In November 2014, we entered into an equity distribution agreement in the 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. During 2014, we utilized the remainder of our previous equity distribution agreement in the aggregate amount of $300 million. At December 31, 2014, we had approximately $514 million of registered common units available for issuance under our “at-the-market” equity program.

During the year ended December 31, 2014, we sold approximately 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.

As a result of these transactions, ONEOK’s aggregate ownership interest in us decreased to 37.8 percent at December 31, 2014, from 41.2 percent at December 31, 2013.

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 approximately 681 thousand 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.

In March 2012, we completed an underwritten public offering of 8.0 million common units at a public offering price of $59.27 per common unit, generating net proceeds of approximately $460 million. We also sold 8.0 million common units to ONEOK in a private placement, generating net proceeds of approximately $460 million. In conjunction with the issuances, ONEOK Partners GP contributed approximately $19 million in order to maintain its 2 percent general partner interest in us.

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, 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
September 30, 2012	$	0.685	October 24, 2012	November 14, 2012
June 30, 2012	$	0.660	July 26, 2012	August 15, 2012
March 31, 2012	$	0.635	April 19, 2012	May 15, 2012
December 31, 2011	$	0.610	January 19, 2012	February 14, 2012

The following table shows our distributions paid during the periods indicated:

	Years Ended December 31,					
	2014		2013		2012	
	(Thousands, except per unit amounts)					
Distribution per unit	**$**	**3.01**	$	2.87	$	2.59
General partner distributions	**$**	**21,044**	$	18,193	$	15,217
Incentive distributions		**304,999**		251,664		186,130
Distributions to general partner		**326,043**		269,857		201,347
Limited partner distributions to ONEOK		**279,292**		266,302		235,442
Limited partner distributions to other unitholders		**446,910**		373,554		324,123
Total distributions paid	**$**	**1,052,245**	$	909,713	$	760,912

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,					
	2014		2013		2012	
	(Thousands, except per unit amounts)					
Distribution per unit	**$**	**3.07**	$	2.89	$	2.69
General partner distributions	**$**	**22,109**	$	18,625	$	16,355
Incentive distributions		**326,022**		259,466		210,095
Distributions to general partner		**348,131**		278,091		226,450
Limited partner distributions to ONEOK		**284,860**		268,157		249,600
Limited partner distributions to other unitholders		**472,466**		384,988		341,704
Total distributions declared	**$**	**1,105,457**	$	931,236	$	817,754

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.

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, 2013	$	(99,322)
Other comprehensive income (loss) before reclassifications		32,141
Amounts reclassified from accumulated other comprehensive income (loss)		8,344
Net current-period other comprehensive income (loss) attributable to ONEOK Partners		40,485
December 31, 2013		(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)**

(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, 2014		2013		Affected Line Item in the Consolidated Statements of Income
	(*Thousands of dollars*)				
Unrealized (gains) losses on risk-management assets/ liabilities					
Commodity contracts	**$**	**21,052**	$	(1,689)	Commodity sales revenues
Interest-rate contracts		**10,601**		10,033	Interest expense
Total reclassifications for the period attributable to ONEOK Partners	**$**	**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 unit 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 $326.0 million, $259.5 million and $210.1 million for 2014, 2013 and 2012, 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, 2014	2013	2012
	(*Thousands of dollars*)		
Current income tax provision			
Federal	**$ 59**	$ 56	$ (156)
State	**1,777**	5,358	3,446
Total current income tax provision	**1,836**	5,414	3,290
Deferred income tax provision			
Federal	**5,033**	4,303	6,330
State	**5,799**	1,141	485
Total deferred income tax provision	**10,832**	5,444	6,815
Total provision for income taxes	**$ 12,668**	$ 10,858	$ 10,105

The following table is a reconciliation of our income tax provision for the periods indicated:

	Years Ended December 31, 2014	2013	2012
	(*Thousands of dollars*)		
Income before income taxes	**$ 924,003**	$ 814,841	$ 898,533
Less: Net income attributable to noncontrolling interests	**1,037**	357	438
Income attributable to ONEOK Partners, L.P. before income taxes	**922,966**	814,484	898,095
Federal statutory income tax rate	**35.0%**	35.0%	35.0%
Provision for federal income taxes	**323,038**	285,069	314,333
Partnership earnings not subject to tax	**(318,021)**	(280,992)	(307,839)
State income taxes, net of federal benefit	**7,576**	6,095	4,530
Other, net	**75**	686	(919)
Income tax provision	**$ 12,668**	$ 10,858	$ 10,105

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. The prior period has been recast to conform to the current year presentation.

	Years Ended December 31, 2014	2013
	(*Thousands of dollars*)	
Deferred tax assets		
Federal and state net operating loss	**$ 3,179**	$ 1,410
Other	**1,626**	1,521
Total deferred tax assets	**4,805**	2,931
Deferred tax liabilities		
Excess of tax over book depreciation	**61,120**	48,433
Regulatory assets	**1,962**	1,978
Total deferred tax liabilities	**63,082**	50,411
Net deferred tax liabilities	**$ 58,277**	$ 47,480

Income taxes payable at December 31, 2014 and 2013, were not material.

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, 2014	December 31, 2013
		(Thousands of dollars)	
Northern Border Pipeline	50%	**$ 387,253**	$ 404,803
Overland Pass Pipeline Company	50%	**466,977**	466,671
Fort Union Gas Gathering	37%	**127,876**	125,220
Bighorn Gas Gathering	49%	**7,924**	87,837
Other	Various	**142,623**	145,307
Investments in unconsolidated affiliates (a)		**$ 1,132,653**	$ 1,229,838

(a) - Equity method goodwill (Note A) was $170.9 million and $224.3 million at December 31, 2014 and 2013, respectively.

Equity Earnings from Investments - The following table sets forth our equity earnings from investments for the periods indicated:

	Years Ended December 31,		
	2014	2013	2012
		(Thousands of dollars)	
Share of investee earnings (loss)			
Northern Border Pipeline	**$ 69,819**	$ 65,046	$ 72,705
Overland Pass Pipeline Company	**25,906**	20,461	20,043
Fort Union Gas Gathering	**16,619**	15,826	17,218
Bighorn Gas Gathering (a)	**(25,621)**	1,952	3,820
Other	**7,701**	7,232	9,238
Total share of investee earnings	**$ 94,424**	$ 110,517	$ 123,024
Impairment of investment in Bighorn Gas Gathering	**(53,421)**	—	—
Equity earnings from investments	**$ 41,003**	$ 110,517	$ 123,024

(a) Includes proportionate share of investee impairment of long-lived assets charge of $23.0 million in 2014.

Unconsolidated Affiliates Financial Information - The following tables set forth summarized combined financial information of our unconsolidated affiliates for the periods indicated:

	December 31, 2014	December 31, 2013
	(Thousands of dollars)	
Balance Sheet		
Current assets	**$ 153,293**	$ 155,310
Property, plant and equipment, net	**$ 2,440,714**	$ 2,557,571
Other noncurrent assets	**$ 35,668**	$ 34,478
Current liabilities	**$ 95,026**	$ 98,967
Long-term debt	**$ 428,385**	$ 442,103
Other noncurrent liabilities	**$ 73,767**	$ 58,221
Accumulated other comprehensive loss	**$ (2,063)**	$ (2,291)
Owners' equity	**$ 2,034,560**	$ 2,150,359

	Years Ended December 31,		
	2014	**2013**	**2012**
	(*Thousands of dollars*)		
Income Statement			
Operating revenues	**$ 548,491**	$ 528,665	$ 573,197
Operating expenses (a)	**$ 309,990**	$ 256,292	$ 269,858
Net income (a)	**$ 214,410**	$ 248,998	$ 279,766
Distributions paid to us	**$ 139,019**	$ 137,498	$ 155,741

(a) Includes long-lived asset impairment charge on Bighorn Gas Gathering in 2014.

We incurred expenses in transactions with unconsolidated affiliates of $62.0 million, $53.8 million and $36.1 million for 2014, 2013 and 2012, respectively, primarily related to Overland Pass Pipeline Company and Northern Border Pipeline. Accounts payable to our equity method investees at December 31, 2014 and 2013, were $20.5 million and $6.9 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 approximately $30.8 million.

In September 2012, Northern Border Pipeline filed with the FERC a settlement with its customers to modify its transportation rates. In January 2013, the settlement was approved and the new rates became effective January 1, 2013. The new long-term transportation rates are approximately 11 percent lower compared with previous rates.

Bighorn Gas Gathering - Producers have primarily focused their development efforts on crude oil and NGL-rich supply basins rather than areas with dry natural gas production, such as the coal-bed methane areas in the Powder River Basin. The reduced coal-bed methane development activities and natural production declines in the dry natural gas formations of the Powder River Basin have resulted in lower natural gas volumes available to be gathered. While the reserve potential in the dry natural gas formations of the Powder River Basin still exists, future drilling and development in this area will be affected by commodity prices and producers' alternative prospects.

During 2014, the volumes gathered on the Bighorn Gas Gathering system, in which we own a 49 percent equity interest and which operates in the coal-bed methane area of the Powder River Basin, declined at a rate greater than in prior periods and greater than expected. Due to these additional declines in volumes, Bighorn Gas Gathering recorded an impairment of its underlying assets in September 2014, when the operator determined that the volume decline would be sustained for the foreseeable future. As a result of these developments, we reviewed our equity method investment in Bighorn Gas Gathering for impairment as of September 30, 2014. We recorded noncash impairment charges of $76.4 million related to Bighorn Gas Gathering. The noncash impairment charges are included in equity earnings from investments in our accompanying Consolidated Statements of Income. The net book value of our equity method investment in Bighorn Gas Gathering is $7.9 million at December 31, 2014, and no equity method goodwill remains. We determined that there were no impairments to investments in unconsolidated affiliates in 2013 or 2012.

A continued decline in volumes gathered in the coal-bed methane area of the Powder River Basin may reduce our ability to recover the carrying value of our equity investments in this area and could result in additional noncash charges to earnings. The net book value of our remaining equity method investments in this dry natural gas area is $206.0 million, which includes

$130.5 million of equity method goodwill. We expect the commodity price environment to remain depressed for at least the near term, which has caused producers to announce plans for reduced drilling for crude oil and natural gas, which we expect will slow volume growth or reduce volumes of natural gas delivered to systems owned by our equity method investments.

N. RELATED-PARTY TRANSACTIONS

Intersegment and affiliate sales are recorded on the same basis as sales to unaffiliated customers. 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 years ended December 31, 2013 and 2012, 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 years ended December 31, 2013 and 2012, 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 operates Guardian Pipeline, Viking Gas Transmission and Midwestern Gas Transmission according to each pipeline's operating 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 years ended December 31, 2013 and 2012, 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,		
	2014	**2013**	**2012**
		(*Thousands of dollars*)	
Revenues	**$ 53,526**	$ 340,743	$ 352,099
Expenses			
Cost of sales and fuel	**$ 10,835**	$ 37,963	$ 33,094
Administrative and general expenses	**330,541**	265,448	246,050
Total expenses	**$ 341,376**	$ 303,411	$ 279,144

ONEOK Partners GP made additional general partner contributions to us of approximately $23 million and $12 million in 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, pipeline equipment and vehicles. Rental expense in 2014, 2013 and 2012 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 the periods presented:

	Firm Transportation and Storage Contracts
	(*Millions of dollars*)
2015	$ 33.6
2016	32.1
2017	30.4
2018	29.4
2019	28.8
Thereafter	68.5
Total	$ 222.8

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, wetland 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. On March 28, 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.

Our expenditures for environmental assessment, mitigation, remediation and compliance to date have not been significant in relation to our financial position, results of operations or cash flows, and our expenditures related to environmental matters have had no material effects on earnings or cash flows during the years ended December 31, 2014, 2013 and 2012.

The EPA's "Tailoring Rule" regulates GHG emissions at new or modified facilities that meet certain criteria. Affected facilities are required to review best available control technology (BACT), 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, on June 23, 2014, the Supreme Court of the United States, 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. However, the 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. We are in the process of evaluating the effects the decision and related pending judicial proceedings at the lower court level may have on our existing operations and the opportunities it creates for 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 EPA's final rule reflects significant changes from the proposal issued in 2011 and allows for more manageable compliance options. 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.

The rule was most recently amended in December 2014. The EPA has indicated that further amendments may be issued in 2015. Based on the amendments, our understanding of pending stakeholder responses to the NSPS rule and the proposed rule-making, we do not anticipate a material impact to our anticipated capital, operations and maintenance costs resulting from compliance with the regulation. However, the EPA may issue additional responses, amendments and/or policy guidance on the final rule, which could alter our present expectations. Generally, the NSPS rule will require expenditures for updated emissions controls, monitoring and record-keeping requirements at affected facilities in the crude oil and natural gas industry. We do not expect these expenditures will have a material impact on our results of operations, financial position or 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.

The potential capital and operating expenditures related to this legislation, the associated regulations or other new pipeline safety regulations are unknown.

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 of 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 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 earnings. The accounting policies of the segments are described in Note A. Intersegment and affiliate sales are recorded on the same basis as sales to unaffiliated customers. Net margin is comprised of total revenues less cost of sales and fuel. Cost of sales and fuel includes commodity purchases, fuel, storage and transportation costs.

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. Natural Gas Pipelines segment 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, 2014, 2013 and 2012, 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, 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
Net margin	$ 661,885	$ 1,110,085	$ 328,521	$ 2,626	$ 2,103,117
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 earnings (loss) from investments	$ (56,141)	$ 27,326	$ 69,818	$ —	$ 41,003
Investments in unconsolidated affiliates	$ 254,818	$ 490,582	$ 387,253	$ —	$ 1,132,653
Total assets	$ 4,727,201	$ 8,082,692	$ 1,823,917	$ 737	$ 14,634,547
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, net margin of $386.5 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, net margin of $242.3 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
Net margin	$ 500,627	$ 869,938	$ 285,719	$ (9,224)	$ 1,647,060
Operating costs	193,293	236,638	101,182	(9,600)	521,513
Depreciation and amortization	103,962	89,240	43,541	—	236,743
Gain (loss) on sale of assets	436	843	10,602	—	11,881
Operating income	$ 203,808	$ 544,903	$ 151,598	$ 376	$ 900,685
Equity 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	$ 1,817,675	$ 156,487	$ 12,862,608
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, net margin of $327.4 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, net margin of $217.6 million and operating income of $90.5 million.

Year Ended December 31, 2012	Natural Gas Gathering and Processing	Natural Gas Liquids (a)	Natural Gas Pipelines (b)	Other and Eliminations	Total
			(*Thousands of dollars*)		
Sales to unaffiliated customers	$ 436,629	$ 9,176,389	$ 217,034	$ —	$ 9,830,052
Sales to affiliated customers	253,136	—	98,963	—	352,099
Intersegment revenues	825,948	80,274	4,388	(910,610)	—
Total revenues	$ 1,515,713	$ 9,256,663	$ 320,385	$ (910,610)	$ 10,182,151
Net margin	$ 455,170	$ 907,340	$ 286,060	$ (6,738)	$ 1,641,832
Operating costs	164,033	223,844	101,899	(7,236)	482,540
Depreciation and amortization	83,031	74,344	45,726	—	203,101
Loss on sale of assets	2,278	(932)	5,390	—	6,736
Operating income	$ 210,384	$ 608,220	$ 143,825	$ 498	$ 962,927
Equity earnings from investments	$ 29,103	$ 20,701	$ 73,220	$ —	$ 123,024
Investments in unconsolidated affiliates	$ 333,210	$ 494,878	$ 393,317	$ —	$ 1,221,405
Total assets	$ 3,040,198	$ 5,620,420	$ 1,812,711	$ 485,901	$ 10,959,230
Noncontrolling interests in consolidated subsidiaries	$ 4,752	$ —	$ —	$ 15	$ 4,767
Capital expenditures	$ 566,126	$ 968,549	$ 25,383	$ 455	$ 1,560,513

(a) - Our Natural Gas Liquids segment has regulated and nonregulated operations. Our Natural Gas Liquids segment's regulated operations had revenues of $470.6 million, of which $397.7 million related to sales within the segment, net margin of $276.3 million and operating income of $162.8 million.
(b) - Our Natural Gas Pipelines segment has regulated and nonregulated operations. Our Natural Gas Pipelines segment's regulated operations had revenues of $251.5 million, net margin of $220.3 million and operating income of $99.3 million.

Q. QUARTERLY FINANCIAL DATA (UNAUDITED)

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 margin	**$ 509,634**	**$ 494,333**	**$ 536,165**	**$ 562,985**
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**

Year Ended December 31, 2013	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(Thousands of dollars, except per unit amounts)			
Revenues	$ 2,517,447	$ 2,768,179	$ 3,134,733	$ 3,448,914
Net margin	$ 370,599	$ 411,953	$ 423,574	$ 440,934
Net income	$ 156,685	$ 202,454	$ 216,400	$ 228,444
Net income attributable to ONEOK Partners, L.P.	$ 156,599	$ 202,367	$ 216,310	$ 228,350
Limited partners' per unit net income	$ 0.42	$ 0.62	$ 0.64	$ 0.67

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, 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	—	—	**10,088.6**	—	**10,088.6**
Net margin	—	—	**2,103.1**	—	**2,103.1**
Operating expenses					
Operations and maintenance	—	—	**599.1**	—	**599.1**
Depreciation and amortization	—	—	**291.2**	—	**291.2**
General taxes	—	—	**70.6**	—	**70.6**
Total 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 earnings (loss) from investments	**910.3**	**910.3**	**(28.8)**	**(1,750.8)**	**41.0**
Allowance for equity funds used during construction	—	—	**14.9**	—	**14.9**
Other income (expense), net	**331.7**	**331.7**	**1.2**	**(663.4)**	**1.2**
Interest expense	**(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	—	—	10,222.2	—	10,222.2
Net margin	—	—	1,647.1	—	1,647.1
Operating expenses					
Operations and maintenance	—	—	464.7	—	464.7
Depreciation and amortization	—	—	236.7	—	236.7
General taxes	—	—	56.9	—	56.9
Total operating expenses	—	—	758.3	—	758.3
Gain (loss) on sale of assets	—	—	11.9	—	11.9
Operating income	—	—	900.7	—	900.7
Equity earnings from investments	803.6	803.6	45.5	(1,542.2)	110.5
Allowance for equity funds used during construction	—	—	30.5	—	30.5
Other income (expense), net	287.6	287.6	9.8	(575.2)	9.8
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

	Year Ended December 31, 2012				
	Parent	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
			(*Millions of dollars*)		
Revenues					
Commodity sales	$ —	$ —	$ 9,010.2	$ —	$ 9,010.2
Services	—	—	1,172.0	—	1,172.0
Total revenues	—	—	10,182.2	—	10,182.2
Cost of sales and fuel	—	—	8,540.4	—	8,540.4
Net margin	—	—	1,641.8	—	1,641.8
Operating expenses					
Operations and maintenance	—	—	433.0	—	433.0
Depreciation and amortization	—	—	203.1	—	203.1
General taxes	—	—	49.5	—	49.5
Total operating expenses	—	—	685.6	—	685.6
Gain (loss) on sale of assets	—	—	6.7	—	6.7
Operating income	—	—	962.9	—	962.9
Equity earnings from investments	888.0	888.0	50.3	(1,703.3)	123.0
Allowance for equity funds used during construction	—	—	13.6	—	13.6
Other income (expense), net	240.1	240.1	5.0	(480.2)	5.0
Interest expense	(240.1)	(240.1)	(206.0)	480.2	(206.0)
Income before income taxes	888.0	888.0	825.8	(1,703.3)	898.5
Income taxes	—	—	(10.1)	—	(10.1)
Net income	888.0	888.0	815.7	(1,703.3)	888.4
Less: Net income attributable to noncontrolling interests	—	—	0.4	—	0.4
Net income attributable to ONEOK Partners, L.P.	$ 888.0	$ 888.0	$ 815.3	$ (1,703.3)	$ 888.0

Condensed Consolidating Statements of Comprehensive Income

	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

	Year Ended December 31, 2012				
	Parent	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
			(*Millions of dollars*)		
Net income	$ 888.0	$ 888.0	$ 815.7	$ (1,703.3)	$ 888.4
Other comprehensive income (loss)					
Unrealized gains (losses) on derivatives	10.3	46.8	46.8	(93.6)	10.3
Realized (gains) losses on derivatives recognized in net income	(58.5)	(61.5)	(61.5)	123.0	(58.5)
Total other comprehensive income (loss)	(48.2)	(14.7)	(14.7)	29.4	(48.2)
Comprehensive income	839.8	873.3	801.0	(1,673.9)	840.2
Less: Comprehensive income attributable to noncontrolling interests	—	—	0.4	—	0.4
Comprehensive income attributable to ONEOK Partners, L.P.	$ 839.8	$ 873.3	$ 800.6	$ (1,673.9)	$ 839.8

Condensed Consolidating Balance Sheets

	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
Commodity imbalances	—	—	64.8	—	64.8
Materials and supplies	—	—	55.8	—	55.8
Other current assets	1.9	—	42.5	—	44.4
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					
Investments in unconsolidated affiliates	4,248.0	5,469.8	746.1	(9,331.3)	1,132.6
Intercompany notes receivable	8,843.3	7,579.0	—	(16,422.3)	—
Goodwill and intangible assets	—	—	822.4	—	822.4
Other assets	36.2	—	21.8	—	58.0
Total investments and other assets	13,127.5	13,048.8	1,590.3	(25,753.6)	2,013.0
Total assets	$ 13,129.4	$ 13,091.3	$ 14,167.4	$ (25,753.6)	$ 14,634.5
Liabilities and equity					
Current liabilities					
Current maturities of long-term debt	$ —	$ —	$ 7.7	$ —	$ 7.7
Notes payable	1,055.3	—	—	—	1,055.3
Accounts payable	—	—	874.7	—	874.7
Affiliate payables	—	—	36.1	—	36.1
Commodity imbalances	—	—	104.7	—	104.7
Accrued interest	92.0	—	—	—	92.0
Other current liabilities	44.8	—	120.8	—	165.6
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	5,986.5	—	51.9	—	6,038.4
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	$ 13,129.4	$ 13,091.3	$ 14,167.4	$ (25,753.6)	$ 14,634.5

	December 31, 2013				
	Parent	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
Assets			(*Millions of dollars*)		
Current assets					
Cash and cash equivalents	$ —	$ 134.5	$ —	$ —	$ 134.5
Accounts receivable, net	—	—	1,103.1	—	1,103.1
Affiliate receivables	—	—	9.2	—	9.2
Natural gas and natural gas liquids in storage	—	—	188.3	—	188.3
Commodity imbalances	—	—	80.5	—	80.5
Materials and supplies	—	—	54.1	—	54.1
Other current assets	4.8	—	8.6	—	13.4
Total current assets	4.8	134.5	1,443.8	—	1,583.1
Property, plant and equipment					
Property, plant and equipment	—	—	10,755.0	—	10,755.0
Accumulated depreciation and amortization	—	—	1,652.6	—	1,652.6
Net property, plant and equipment	—	—	9,102.4	—	9,102.4
Investments and other assets					
Investments in unconsolidated affiliates	4,336.4	4,593.1	825.6	(8,525.3)	1,229.8
Intercompany notes receivable	6,638.3	6,247.1	—	(12,885.4)	—
Goodwill and intangible assets	—	—	832.2	—	832.2
Other assets	92.7	—	22.4	—	115.1
Total investments and other assets	11,067.4	10,840.2	1,680.2	(21,410.7)	2,177.1
Total assets	$ 11,072.2	$ 10,974.7	$ 12,226.4	$ (21,410.7)	$ 12,862.6
Liabilities and equity					
Current liabilities					
Current maturities of long-term debt	$ —	$ —	$ 7.7	$ —	$ 7.7
Notes payable	—	—	—	—	—
Accounts payable	—	—	1,255.4	—	1,255.4
Affiliate payables	—	—	47.5	—	47.5
Commodity imbalances	—	—	213.6	—	213.6
Accrued interest	92.7	—	—	—	92.7
Other current liabilities	—	—	89.1	—	89.1
Total current liabilities	92.7	—	1,613.3	—	1,706.0
Intercompany debt	—	6,638.3	6,247.1	(12,885.4)	—
Long-term debt, excluding current maturities	5,985.3	—	59.6	—	6,044.9
Deferred credits and other liabilities	—	—	113.0	—	113.0
Commitments and contingencies					
Equity					
Equity excluding noncontrolling interests in consolidated subsidiaries	4,994.2	4,336.4	4,188.9	(8,525.3)	4,994.2
Noncontrolling interests in consolidated subsidiaries	—	—	4.5	—	4.5
Total equity	4,994.2	4,336.4	4,193.4	(8,525.3)	4,998.7
Total liabilities and equity	$ 11,072.2	$ 10,974.7	$ 12,226.4	$ (21,410.7)	$ 12,862.6

Condensed Consolidating Statements of Cash Flows

	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 (less allowance for equity funds used during construction)	—	—	(1,746.0)	—	(1,746.0)
Cash paid for acquisitions, net of cash received	—	—	(814.9)	—	(814.9)
Contributions to unconsolidated affiliates	—	—	(1.0)	—	(1.0)
Distributions received from unconsolidated affiliates	—	17.7	3.4	—	21.1
Proceeds from sale of assets	—	—	7.8	—	7.8
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 notes payable, 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 (less allowance for equity funds used during construction)	—	(2.6)	(1,936.7)	—	(1,939.3)
Cash paid for acquisitions, net of cash received	—	—	(394.9)	—	(394.9)
Contributions to unconsolidated affiliates	—	(30.8)	(4.5)	—	(35.3)
Distributions received from unconsolidated affiliates	—	19.4	11.7	—	31.1
Proceeds from sale of assets	—	—	12.3	—	12.3
Cash 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
Long-term 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

	Year Ended December 31, 2012				
	Parent	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
			(*Millions of dollars*)		
Operating activities					
Cash provided by operating activities	$ 760.9	$ 72.7	$ 873.4	$ (760.9)	$ 946.1
Investing activities					
Capital expenditures (less allowance for equity funds used during construction)	—	—	(1,560.5)	—	(1,560.5)
Contributions to unconsolidated affiliates	—	—	(30.8)	—	(30.8)
Distributions received from unconsolidated affiliates	—	23.0	12.3	—	35.3
Proceeds from sale of assets	—	—	10.8	—	10.8
Cash provided by (used in) investing activities	—	23.0	(1,568.2)	—	(1,545.2)
Financing activities					
Cash distributions:					
General and limited partners	(760.9)	(760.9)	—	760.9	(760.9)
Noncontrolling interests	—	—	(0.8)	—	(0.8)
Issuance of long-term debt, net of discounts	1,295.0	—	—	—	1,295.0
Long-term debt financing costs	(9.6)	—	—	—	(9.6)
Intercompany borrowings (advances), net	(1,873.9)	1,167.2	706.7	—	—
Repayment of long-term debt	(350.0)	—	(11.1)	—	(361.1)
Issuance of common units, net of issuance costs	919.4	—	—	—	919.4
Contribution from general partner	19.1	—	—	—	19.1
Cash provided by (used in) financing activities	(760.9)	406.3	694.8	760.9	1,101.1
Change in cash and cash equivalents	—	502.0	—	—	502.0
Cash and cash equivalents at beginning of period	—	35.1	—	—	35.1
Cash and cash equivalents at end of period	$ —	$ 537.1	$ —	$ —	$ 537.1

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, 2014.

The effectiveness of our internal control over financial reporting as of December 31, 2014, 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, 2014, 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

General Partner Board of Directors

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 Gil J. Van Lunsen, 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 2014, our Board of Directors affirmatively determined that Ms. Edwards and Messrs. Malcolm, Mogg, Petersen, Strehl and Van Lunsen 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 2014, our Board of Directors determined that Ms. Edwards and Messrs. Malcolm, Mogg, Petersen, Strehl and Van Lunsen 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. The Board also reviews risks related to the Partnership's business strategies at its annual strategic planning meeting and at other meetings as appropriate.

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 Director - 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	62	Chairman of the Board
Terry K. Spencer	55	President, Chief Executive Officer and Member, Board of Directors
Derek S. Reiners	43	Senior Vice President, Chief Financial Officer and Treasurer
Robert F. Martinovich	57	Executive Vice President and Chief Administrative Officer
Walter S. Hulse III	51	Executive Vice President, Strategic Planning and Corporate Affairs
Stephen W. Lake	51	Senior Vice President, General Counsel and Assistant Secretary
Wesley J. Christensen	61	Senior Vice President, Operations
Sheppard F. Miers III	46	Vice President and Chief Accounting Officer
Julie H. Edwards	56	Member, Board of Directors and Audit Committee
Steven J. Malcolm	66	Member, Board of Directors and Audit Committee
Jim W. Mogg	66	Member, Board of Directors and Audit Committee
Gary N. Petersen	63	Member, Board of Directors, Audit and Conflicts Committees
Craig F. Strehl	57	Member, Board of Directors and Vice Chairman, Audit and Conflicts Committees
Gil J. Van Lunsen	72	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. 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.

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.

Gil Van Lunsen was appointed to our Board of Directors in May 2006. Mr. Van Lunsen was a managing partner of KPMG LLP and led the firm's Tulsa, Oklahoma, office prior to his retirement in June 2000. During his 33-year career, Mr. Van Lunsen held various positions of increasing responsibility within KPMG and was elected to the partnership in 1977. He is currently Chairman of the Audit Committee of Array Biopharma, Inc. in Boulder, Colorado, and has been a member of its Board of Directors since 2002. He is also a member of the Board of Directors and Chairman of the Audit Committee of M/A-COM Technology Solutions Holdings, Inc. in Lowell, Massachusetts, and has been a member of its board since August 2010. Mr. Van Lunsen received a B.S./B.A. in Accounting from the University of Denver.

As a former partner of KPMG LLP, Mr. Van Lunsen 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. Van Lunsen has also developed an in-depth knowledge of the critical accounting, operational and financial issues facing our company and our industry. In light of Mr. Van Lunsen's extensive industry, finance and accounting experience and knowledge, ONEOK has concluded that Mr. Van Lunsen should continue as a member of our Board of Directors.

Director Compensation

Compensation for our nonmanagement directors for the year ended December 31, 2014, 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 2014.

2014 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 ($)	All Other Compensation ($)	Total ($)
John W. Gibson (1)	$ 160,417						$ 160,417
Julie H. Edwards	$ 150,000	—	—	—	—	—	$ 150,000
Steven J. Malcolm	$ 150,000	—	—	—	—	—	$ 150,000
Jim W. Mogg	$ 150,000	—	—	—	—	—	$ 150,000
Gary N. Petersen	$ 150,000	—	—	—	—	—	$ 150,000
Craig F. Strehl	$ 150,000	—	—	—	—	—	$ 150,000
Gil J. Van Lunsen	$ 160,000	—	—	—	—	—	$ 160,000

(1) Mr. Gibson became our nonexecutive Chairman of the Board on January 31, 2014, and his compensation was prorated for his 11 months of service in 2014.

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 2014, 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 2014 fiscal year or written representations from certain reporting persons that no Form 5s were required for those persons, we believe that during 2014 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 2015 Proxy Statement as filed with the SEC (ONEOK 2015 Proxy Statement), which is incorporated herein by this reference. A copy of the ONEOK 2015 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 2014 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 2014

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
John W. Gibson	2014	$ 75,780	$ —	$ 51,690	$ 3,606,343	$ 4,926	$ 3,738,739
Chairman and Chief Executive Officer through January 30, 2014 Chairman of the Board effective January 31, 2014	2013	$ 617,785	$ 1,937,826	$ 290,684	$ —	$ 78,512	$ 2,924,807
	2012	$ 611,531	$ 2,149,828	$ 675,903	$ 2,303,843	$ 94,891	$ 5,835,996
Terry K. Spencer	2014	$ 670,058	$ 2,157,814	$ 447,981	$ 539,424	$ 54,709	$ 3,869,986
President through January 30, 2014 President and Chief Executive Officer effective January 31, 2014	2013	$ 390,180	$ 887,578	$ 152,821	$ 29,645	$ 44,176	$ 1,504,400
	2012	$ 386,230	$ 1,061,643	$ 334,733	$ 342,156	$ 48,544	$ 2,173,306
Derek S. Reiners	2014	$ 358,960	$ 808,883	$ 143,584	$ —	$ 45,233	$ 1,356,660
Senior Vice President, Chief Financial Officer and Treasurer	2013	$ 211,348	$ 352,067	$ 55,276	$ —	$ 28,861	$ 647,552
	2012	$ 186,678	$ 212,329	$ 102,995	$ —	$ 36,731	$ 538,733
Robert F. Martinovich	2014	$ 478,613	$ 808,883	$ 215,376	$ —	$ 64,186	$ 1,567,058
Executive Vice President, Operations through January 30, 2014 Executive Vice President, Commercial effective January 31, 2014	2013	$ 325,150	$ 528,871	$ 104,048	$ —	$ 52,273	$ 1,010,342
	2012	$ 321,859	$ 928,939	$ 247,831	$ —	$ 72,973	$ 1,571,602
Stephen W. Lake	2014	$ 430,752	$ 808,883	$ 181,873	$ —	$ 55,571	$ 1,477,079
Senior Vice President, General Counsel and Assistant Secretary	2013	$ 292,635	$ 352,067	$ 78,036	$ —	$ 43,786	$ 766,524
	2012	$ 273,580	$ 398,117	$ 186,678	$ —	$ 43,104	$ 901,479
Wesley J. Christensen	2014	$ 400,000	$ 845,029	$ 195,000	$ 138,304	$ 40,654	$ 1,618,987
Senior Vice President, Operations	2013	$ 340,000	$ 541,391	$ 100,000	$ 33,100	$ 43,482	$ 1,057,973
	2012	$ 300,000	$ 329,848	$ 220,000	$ 102,794	$ 46,211	$ 998,853

(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 2014, 2013 and 2012 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, 2014, included in the ONEOK 2014 Annual Report on Form 10-K filed with the SEC on February 25, 2015.

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	2014	2013	2012
John W. Gibson	$ —	$ 3,159,593	$ 3,536,415
Terry K. Spencer	$ 3,549,678	$ 1,447,155	$ 1,746,378
Derek S. Reiners	$ 1,329,442	$ 574,781	$ 349,276
Robert F. Martinovich	$ 1,329,442	$ 862,171	$ 1,528,082
Stephen W. Lake	$ 1,329,442	$ 574,781	$ 654,892
Wesley J. Christensen	$ 1,388,850	$ 883,870	$ 542,592

(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 2014 awards under the ONEOK annual short-term incentive plan, see "2014 Annual Short-Term Incentive Awards" in the Executive Compensation Discussion and Analysis section of the ONEOK 2015 Proxy Statement.

(3) The amounts reflected represent the aggregate change during 2014 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 will be set forth in the Executive Compensation and Discussion and Analysis section of the ONEOK 2015 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 2014, the change in pension value reflects not only the increase due to additional service and pay for the year, but also an increase in present value due to the lower discount rate (4.50 percent for fiscal 2014, down from 5.25 percent in 2013). The 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. Gibson, Spencer and Christensen.

During 2013, the allocated pension value for Mr. Gibson decreased $367,411. There were no above-market or preferential earnings credited on any of the named executive officer's nonqualified deferred compensation.

(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 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
John W. Gibson	2014	$ —	$ 4,547	$ —	$ —	$ 379
	2013	$ 68,086	$ 9,950	$ —	$ —	$ 476
	2012	$ 84,970	$ 9,656	$ —	$ —	$ 265
Terry K. Spencer	2014	$ 38,768	$ 14,933	$ —	$ —	$ 1,009
	2013	$ 33,750	$ 9,950	$ —	$ —	$ 476
	2012	$ 38,623	$ 9,656	$ —	$ —	$ 265
Derek S. Reiners	2014	$ 19,145	$ 14,933	$ 9,956	$ 192	$ 1,009
	2013	$ 13,461	$ 9,950	$ 4,975	$ —	$ 476
	2012	$ 18,764	$ 9,656	$ 8,046	$ —	$ 265
Robert F. Martinovich	2014	$ 38,289	$ 14,933	$ 9,956	$ —	$ 1,009
	2013	$ 36,872	$ 9,950	$ 4,975	$ —	$ 476
	2012	$ 54,877	$ 9,656	$ 8,046	$ 129	$ 265
Stephen W. Lake	2014	$ 29,674	$ 14,933	$ 9,956	$ —	$ 1,009
	2013	$ 28,386	$ 9,950	$ 4,975	$ —	$ 476
	2012	$ 25,138	$ 9,656	$ 8,046	$ —	$ 265
Wesley J. Christensen	2014	$ 24,000	$ 15,600	$ —	$ —	$ 1,054
	2013	$ 27,450	$ 15,300	$ —	$ —	$ 732
	2012	$ 30,800	$ 15,000	$ —	$ —	$ 411

(a) Additional information on the ONEOK, Inc. Nonqualified Deferred Compensation Plan, will be set forth in "Long-Term Compensation Plans - Nonqualified Deferred Compensation Plan" in the Executive Compensation Discussion and Analysis section of the ONEOK 2015 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) ONEOK's 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 Retirement Plan. ONEOK plans to make a contribution to the 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.

The named executive officers did not receive perquisites or other personal benefits with an aggregate value of $10,000 or more during 2014, 2013 or 2012.

(5) Mr. Gibson retired as our Chief Executive Officer effective January 31, 2014. The allocated portion of his annual salary prior to his retirement was $75,780.

(6) As a result of his retirement as our Chief Executive Officer effective January 31, 2014, the allocation of Mr. Gibson's short-term incentive payout was prorated.

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 Thrift Plan for Employees of ONEOK, Inc. and Subsidiaries, the ONEOK Profit-Sharing Plan and the ONEOK, Inc. Employee Nonqualified Deferred Compensation Plan;
- amounts accrued and vested through the Retirement Plan for Employees of ONEOK, Inc. and Subsidiaries 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 of 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 30 percent or more of our outstanding voting securities, has beneficial ownership of 30 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, 2014, 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, 2014. 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, 2014, and a performance factor based on ONEOK's total shareholder return relative to the designated peer group on that date.

John W. Gibson	Termination Upon Death, Disability or Retirement (1)	Termination Without Cause	Qualifying Termination Following a Change in Control
Cash Severance	$ —	$ —	$ —
Health and Welfare Benefits	$ 74,779	$ —	$ —
Equity			
Restricted Units	$ 928,948	$ —	$ —
Performance Units	$ —	$ —	$ —
Total	$ 928,948	$ —	$ —
Total	$ 1,003,727	$ —	$ —

(1) Mr. Gibson retired as Chief Executive Officer effective January 31, 2014. The amounts reflected in the table represent the allocated portion of payments to Mr. Gibson upon his retirement and include $74,779 in allocated accrued vacation pay and the allocated portion of the value of 13,987 ONEOK restricted units that vested on a prorated basis upon his retirement. These amounts do not include the value of 108,007 ONEOK performance units that vested at his retirement but which will not be paid out until the end of their respective performance periods.

Terry K. Spencer	Termination Upon Death, Disability or Retirement	Termination Without Cause	Qualifying Termination Following a Change in Control
Cash Severance	$ —	$ —	$ 2,761,640
Health and Welfare Benefits	$ 66,386	$ 66,386	$ 94,600
Equity			
Restricted Units	$ 718,531	$ 718,531	$ 1,108,346
Performance Units	$ 2,277,052	$ —	$ 2,731,785
Total	$ 2,995,583	$ 718,531	$ 3,840,131
Total	$ 3,061,969	$ 784,917	$ 6,696,371

Derek S. Reiners	Termination Upon Death, Disability or Retirement	Termination Without Cause	Qualifying Termination Following a Change in Control
Cash Severance	$ —	$ —	$ 1,220,547
Health and Welfare Benefits	$ 35,564	$ 35,564	$ 63,252
Equity			
Restricted Units	$ 198,082	$ 198,082	$ 342,606
Performance Units	$ 564,930	$ —	$ 725,571
Total	$ 763,012	$ 198,082	$ 1,068,177
Total	$ 798,576	$ 233,646	$ 2,351,976

Robert F. Martinovich	Termination Upon Death, Disability or Retirement	Termination Without Cause	Qualifying Termination Following a Change in Control
Cash Severance	$ —	$ —	$ 1,676,710
Health and Welfare Benefits	$ 47,419	$ 47,419	$ 66,252
Equity			
Restricted Units	$ 528,097	$ 528,097	$ 714,842
Performance Units	$ 1,837,334	$ —	$ 2,136,533
Total	$ 2,365,431	$ 528,097	$ 2,851,375
Total	$ 2,412,850	$ 575,516	$ 4,594,337

Stephen W. Lake	Termination Upon Death, Disability or Retirement	Termination Without Cause	Qualifying Termination Following a Change in Control
Cash Severance	$ —	$ —	$ 1,464,656
Health and Welfare Benefits	$ 34,141	$ 34,141	$ 62,355
Equity			
Restricted Units	$ 273,402	$ 273,402	$ 422,357
Performance Units	$ 866,212	$ —	$ 1,044,576
Total	$ 1,139,614	$ 273,402	$ 1,466,933
Total	$ 1,173,755	$ 307,543	$ 2,993,944

Wesley J. Christensen	Termination Upon Death, Disability or Retirement	Termination Without Cause	Qualifying Termination Following a Change in Control
Cash Severance	$ —	$ —	$ 1,360,000
Health and Welfare Benefits	$ 38,462	$ 38,462	$ 57,556
Equity			
Restricted Units	$ 200,833	$ 200,833	$ 347,364
Performance Units	$ 572,777	$ —	$ 735,649
Total	$ 773,610	$ 200,833	$ 1,083,013
Total	$ 812,072	$ 239,295	$ 2,500,569

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, 2014. 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	19,800,000	12.5%	72,988,252	100%	35.8% (1)
100 West Fifth Street					
Tulsa, OK 74103-4298					
Alerian MLP ETF	10,015,543	5.54%	—	—	3.95% (2)
1290 Broadway					
Suite 1100					
Denver, CO 80203					
ALPS Advisors, Inc.	10,044,900	5.55%	—	—	3.96% (3)
1219 Broadway					
Suite 1100					
Denver, CO 80203					
Kayne Anderson Capital Advisors, L.P. and Richard Kane	10,688,684	5.91%	—	—	4.21% (4)
1800 Avenue of the Stars,					
Third Floor					
Los Angeles, CA 90067					

(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 17, 2015, in which Alerian MLP ETF ("Alerian") reported that, as of December 31, 2014, Alerian beneficially owned, in the aggregate, 10,015,543 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 10,015,543 common units, sole dispositive power with respect to zero common units, and shared dispositive power with respect to 10,015,543 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 17, 2015 in which ALPS Advisors, Inc. ("ALPS") reported that, as of December 31, 2014, ALPS beneficially owned, in the aggregate, 10,044,900 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 10,044,900 common units, sole dispositive power with respect to zero common units, and shared dispositive power with respect to 10,044,900 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 1, 2014, in which Kayne Anderson Capital Advisors, L.P. ("Kane Anderson") and Richard A. Kayne reported that, as of December 31, 2014, Kayne Anderson and Mr. Kayne owned, in the aggregate, 10,668,684 shares of our common stock with respect to which they had sole power to vote zero shares, shared power to vote 10,866,684 shares, sole dispositive power with respect to zero shares, and shared dispositive power with respect to 10,886,684 shares. Kayne Anderson reported that: the reported shares 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.

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, 2015, 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	70,000	*	—	—	*	930,222 (3)	*
Terry K. Spencer	—	—	—	—	—	273,401	*
Derek S. Reiners	—	—	—	—	*	35,175	*
Robert F. Martinovich	288	—	—	—	—	185,784	
Stephen W. Lake		—	—	—	—	19,140	
Wesley J. Christensen	—	—	—	—	—	19,390	
Julie H. Edwards	—	—	—	—	—	37,499	*
Steven J. Malcolm	—	—	—	—	—	10,213	*
Jim W. Mogg	2,000	*	—	—	*	—	—
Gary N. Petersen	20,284	*	—	—	*	—	*
Craig F. Strehl	9,400	*	—	—	*	—	—
Gil J. Van Lunsen	4,000	*	—	—	*	—	—
All directors and executive officers as a group	108,372	*	—	—	*	1,515,847	*

* 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 and Thrift Plan for Employees of ONEOK, Inc. and Subsidiaries, and shares that the director or executive officer had the right to acquire within 60 days of February 1, 2014.
(3) Excludes 295,544 shares, the receipt of which was deferred upon vesting in January 2012 under the deferral provisions of our Equity Compensation Plan ("ECP"), which shares will be issued to Mr. Gibson on July 17, 2015.

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.

On January 31, 2014, ONEOK separated its natural gas distribution business into a stand-alone publicly traded company, named ONE Gas. ONEOK and its subsidiaries continue to own the entire general partner interest in us and limited partners units, which together at December 31, 2014, represented a 37.8 percent interest in us. We do not expect the ONEOK separation of ONE Gas to materially affect us.

Other relationships with ONEOK include the following:

Cash Distributions - ONEOK and its affiliates own all of our 72,988,252 Class B units, 19,800,000 of our common units and our entire 2 percent general partner interest, which together constituted a 37.8 percent ownership interest in us at December 31, 2014. In 2014, we paid total cash distributions to ONEOK of $605.3 million, which included $305.0 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 2014, the aggregate amount charged by ONEOK and their affiliates to us for their services was approximately $330.5 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 - Our Natural Gas Gathering and Processing segment sold $41.2 million of natural gas to ONEOK and its subsidiaries during 2014. Of our Natural Gas Pipelines segment's revenues, $12.3 million were from ONEOK and its subsidiaries during 2014 for both transportation and storage services.

Our Natural Gas Gathering and Processing segment and Natural Gas Liquids segment purchase a portion of the natural gas used in their operations from ONEOK and its subsidiaries. In 2014, the aggregate amount charged by ONEOK and its affiliates to us for their services was approximately $10.8 million. These transactions were with our affiliate ONEOK Energy Services Company, a subsidiary of ONEOK. In June 2013, ONEOK announced an accelerated wind down of ONEOK Energy Services Company operations that was substantially completed by April 2014. We expect to continue providing our customers midstream services, including marketing natural gas, NGLs and condensate.

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 2014, Northern Border Pipeline's revenue for capacity contracted on a firm basis included $8.1 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 2014, Overland Pass Pipeline Company's revenue for capacity contracted on a firm basis included $43.9 million from us.

Contracts - Before the completion of its wind down on March 31, 2014, ONEOK Energy Services Company, a subsidiary of ONEOK, from time to time entered into commodity derivative contracts on behalf of our Natural Gas Gathering and Processing segment. In the first quarter 2014, outstanding commodity derivative positions with third parties entered into by ONEOK Energy Services Company on our behalf were transferred to us. Beginning in the second quarter 2014, we enter into all commodity derivative contracts directly with unaffiliated third parties. See Note D of the Notes to Consolidated Financial Statements in this Annual Report for a discussion of our derivative instruments and hedging activities.

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 2014 and 2013 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, 2014 and 2013:

	2014	2013
	(*Thousands of dollars*)	
Audit fees	$ 1,596.4	$ 1,600.5
Audit-related fees	—	—
Tax fees (1)	744.8	769.1
All other fees (2)	0.3	34.6
Total	$ 2,341.5	$ 2,404.2

(1) Tax fees consisted of fees for tax compliance, tax planning or tax services, including preparation of our annual K-1 statements.

(2) All other fees consisted of fees for professional education seminars.

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 2014 audit, a plan was submitted to and approved by the Audit Committee setting forth the services expected to be rendered during 2014 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

(1) Financial Statements		Page No.
(a)	Report of Independent Registered Public Accounting Firm	79
(b)	Consolidated Statements of Income for the years ended December 31, 2014, 2013 and 2012	80
(c)	Consolidated Statements of Comprehensive Income for the years ended December 31, 2014, 2013 and 2012	81
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(e)	Consolidated Statements of Cash Flows for the years ended December 31, 2014, 2013 and 2012	83
(f)	Consolidated Statements of Changes in Equity for the years ended December 31, 2014, 2013 and 2012	84-85
(g)	Notes to Consolidated Financial Statements	86-121

(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 Not used.

4.2 Not used.

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	Underwriting Agreement, dated September 10, 2012, among ONEOK Partners, L.P. and ONEOK Partners Intermediate Limited Partnership and RBS Securities Inc., Mitsubishi UFJ Securities (USA), Inc. and U.S. Bancorp Investments, Inc., as representative of the several underwriters named therein (incorporated by reference from Exhibit 1.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on September 13, 2012 (File No. 1-12202)).
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 February 28, 2012, among ONEOK Partners, L.P. and Barclays Capital Inc., Citigroup Global Capital Markets Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Morgan Stanley & Co. 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 March 2, 2012 (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.
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).
12	Computation of Ratio of Earnings to Fixed Charges for the years ended December 31, 2014, 2013, 2012, 2011 and 2010.
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)).
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, 2014, 2013 and 2012; (iii) Consolidated Statements of Comprehensive Income for the years ended December 31, 2014, 2013 and 2012; (iv) Consolidated Balance Sheets at December 31, 2014 and 2013; (v) Consolidated Statements of Cash Flows for the years ended December 31, 2014, 2013 and 2012; (vi) Consolidated Statement of Changes in Equity for the years ended December 31, 2014, 2013 and 2012; 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 24, 2015

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 24th day of February 2015.

/s/ John W. Gibson	/s/ Terry K. Spencer
John W. Gibson Chairman of the Board	Terry K. Spencer President, Chief Executive Officer and Director
/s/ Derek S. Reiners	/s/ Sheppard F. Miers III
Derek S. Reiners Senior Vice President, Chief Financial Officer and Treasurer	Sheppard F. Miers III Vice President and Chief Accounting Officer
/s/ Julie H. Edwards	/s/ Steven J. Malcolm
Julie H. Edwards Director	Steven J. Malcolm Director
/s/ Jim W. Mogg	/s/ Gary N. Petersen
Jim W. Mogg Director	Gary N. Petersen Director
/s/ Craig F. Strehl	/s/ Gil J. Van Lunsen
Craig F. Strehl Director	Gil J. Van Lunsen Director

CORPORATE INFORMATION

ONEOK Partners is a publicly traded master limited partnership engaged in the natural gas gathering and processing, natural gas liquids and natural gas pipelines businesses.

ONEOK Partners is listed on the New York Stock Exchange under the symbol OKS.

Its sole general partner, ONEOK Partners GP, L.L.C., is a subsidiary of ONEOK, Inc. (NYSE: OKE), an energy company founded in 1906.

ONEOK owns 37.8 percent of the partnership as of December 31, 2014.

Publicly Traded Partnership Attributes
Unitholders own limited partnership common units instead of shares of stock and receive cash distributions rather than dividends. A partnership generally is not a taxable entity and does not pay federal income taxes. All of the income, gains, losses, deductions or credits flow through the partnership to the unitholders on a per-unit basis. Unitholders are required to report their allocated share of these amounts on their income tax returns whether or not cash distributions are made by the partnership to unitholders.

Cash distributions paid by the partnership to a unitholder generally are tax deferred, unless the amount of any cash distributed is in excess of the unitholder's adjusted basis in their partnership interest.

Unitholders will receive a tax package, including a Schedule K-1, each year they own units. The partnership provides each unitholder a tax package in March of each year that includes the unitholder's allocated share of reportable partnership income, gains, losses, deductions, credits and other partnership information necessary to file federal and/or state tax returns. Unitholders who have questions should call 800-371-2188.

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

Transfer Agent, Registrar and Distribution-paying Agent
Wells Fargo Shareowner Services
P.O. Box 64874
St. Paul, MN 55164-0854
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 Rating

Standard & Poor's	BBB (stable)
Moody's Investors Service	Baa2 (stable)

Master Limited Partnership Units
Common units for the partnership trade on the New York Stock Exchange under the symbol OKS.

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 Website
ONEOK Partners business and financial information is available at www.oneokpartners.com.

NON-GAAP (GENERALLY ACCEPTED ACCOUNTING PRINCIPLES) FINANCIAL MEASURES

ONEOK Partners has disclosed in this annual report historical adjusted EBITDA, DCF and coverage ratio, which are non-GAAP financial metrics, used to measure 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. DCF is defined as adjusted EBITDA, computed as described above, less interest expense, maintenance capital expenditures and equity earnings from investments, adjusted for cash distributions received and certain other items. 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.

The partnership believes the non-GAAP financial measures described above are useful to investors because they are used by many companies in its industry to measure financial performance and are commonly employed by financial analysts and others to evaluate the financial performance of the partnership and to compare the financial performance of the partnership with the performance of other publicly traded partnerships within its industry. Adjusted EBITDA, DCF and coverage ratio should not be considered alternatives to net income, earnings per unit 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 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 STATEMENT

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 Partners, L.P. Annual Report on Form 10-K for the year ended December 31, 2014, included in this annual report.

MIX
Paper from responsible sources
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