ONEOK PARTNERS, L.P.

“PROGRESS CONTINUES.”

2012 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 pipelines and natural gas liquids businesses.
- Our sole general partner is a subsidiary of ONEOK, Inc., an energy company founded in 1906 that's involved in natural gas distribution and energy services, and owns 43.4 percent of the partnership.

FINANCIAL HIGHLIGHTS

Year Ended December 31	2012	2011	2010
Consolidated financial information (millions of dollars)			
Net margin	$ 1,641.8	$ 1,577.4	$ 1,144.9
Operating income	$ 962.9	$ 939.5	$ 586.3
Net income attributable to ONEOK Partners, L.P.	$ 888.0	$ 830.3	$ 472.7
Total assets	$ 10,959.2	$ 8,946.7	$ 7,920.1
Long-term debt to capitalization	52%	53%	46%
Capital expenditures (millions of dollars)			
Growth	$ 1,458.3	$ 969.4	$ 290.2
Maintenance	$ 102.2	$ 94.0	$ 62.5
Total capital expenditures	$ 1,560.5	$ 1,063.4	$ 352.7
Common unit data*			
Common units outstanding at year-end	146,827,354	130,827,354	130,827,354
Class B units outstanding at year-end	72,988,252	72,988,252	72,988,252
Total units outstanding at year-end	219,815,606	203,815,606	203,815,606
Distributions declared per limited partner unit*	$ 2.69	$ 2.365	$ 2.25
Market price range*			
High	$ 61.23	$ 57.94	$ 40.76
Low	$ 51.16	$ 37.74	$ 27.98
Year-end	$ 53.99	$ 57.74	$ 39.75

Reconciliation of Net Income to EBITDA and Distributable Cash Flow (millions of dollars)	2012	2011
Net income	$ 888	$ 831
Interest expense	206	223
Depreciation and amortization	203	178
Income taxes	10	13
Allowance for equity funds used during construction and other	(13)	(3)
EBITDA	$ 1,294	$ 1,242
Interest expense	(206)	(223)
Maintenance capital	(102)	(94)
Equity earnings from investments	(123)	(127)
Distributions received from unconsolidated affiliates	156	156
Other	(11)	(8)
Distributable cash flow	$ 1,008	$ 946

** Split adjusted*

On the cover:

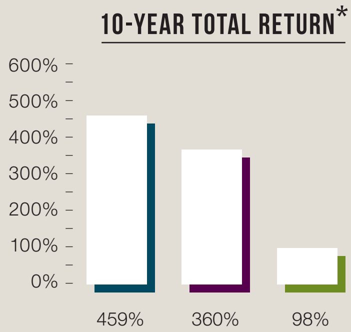
Bakken NGL pipeline construction in northeast Wyoming.

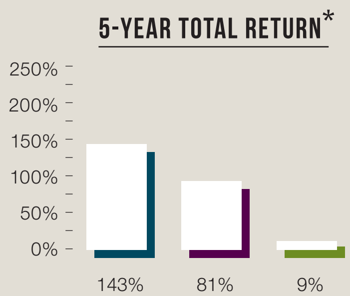
MEASURING OUR PROGRESS

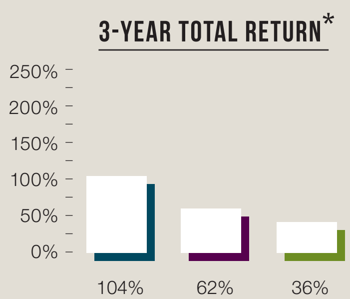
LETTER TO UNITHOLDERS

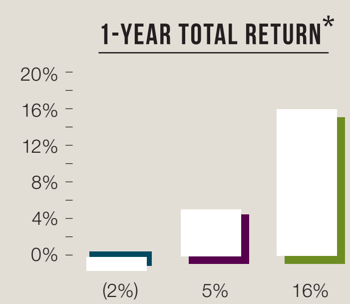
There are many ways to measure progress. For example, a child's growth can be measured by marks on a wall and by milestones achieved and celebrated.

To ensure our growth continues at ONEOK Partners, we continually raise the bar by which *we're* measured to better serve our customers and deliver value to you, our unitholders.









ONEOK Partners, L.P.
Alerian MLP Index
S&P 500 Index

As of December 31, 2012

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

We accomplished a lot in 2012. It was a year of project execution, as we made progress in our $5 billion capital-growth program for new natural gas and natural gas liquids (NGL) infrastructure that, when completed in 2015, will increase the volumes on our systems and create added flexibility for our operations. Milestones achieved in 2012 and early 2013 included:

- Completing the Stateline I and Stateline II natural gas processing plants in western North Dakota;
- Building the first-ever pipeline to transport unfractionated NGLs out of the Williston Basin – the Bakken NGL Pipeline;
- Expanding the capacity of our NGL fractionator at Bushton, Kansas;
- Expanding our Mid-Continent NGL pipeline gathering system by constructing approximately 230 miles of pipelines to connect to three new and three expanded, third-party natural gas processing plants; and
- Increasing the capacity on the Arbuckle Pipeline to 240,000 barrels per day (bpd).

Additionally, we have a $2 billion-plus backlog of unannounced growth projects that we continue to evaluate. *(See page 22 of this report for more information on our growth projects.)*

In 2012, our distributable cash flow, another measure of progress, increased 7 percent, compared with 2011, despite a market with an oversupply of ethane and propane, and narrow NGL price differentials between the two largest NGL market centers – Conway, Kansas, and Mont Belvieu, Texas. We also increased cash distributions by 11 percent, compared with 2011, perhaps the most important measure for you, the unitholder. We expect that increased earnings from our current growth program will result in average annual earnings before interest, taxes, depreciation and amortization (EBITDA) growth of 15 to 20 percent through 2015. Cash distributions to unitholders are expected to grow by an annual average of 8 to 12 percent during the same period.

We have a responsibility to ourselves, our fellow employees, our communities and our families to ensure that we're always operating our assets safely and environmentally responsibly. We made measurable progress in our environmental, safety and health (ESH) performance in 2012 as we introduced our ESH Management

System Framework to manage risks. Our natural gas pipelines segment went 12 months without an Occupational Safety and Health Administration (OSHA)-recordable injury or illness, and we finished 2012 with zero agency-reportable events in our natural gas gathering and processing, and natural gas pipelines segments. Though we made progress in many ESH areas in 2012 – and I'm proud of what we've done – our work will never be complete in these important areas.

SHAPING AND UNDERSTANDING OUR SUPPLY-AND-DEMAND POINT OF VIEW

The biggest bet you make is on your vision, and second to that, your point of view. Our point of view on supply and demand influences decisions about which projects we will build and where we will build them. Developing a forward-looking point of view on natural gas, NGLs and crude-oil supply and demand is important when we make decisions about how we're going to fulfill our vision of becoming the nation's premier midstream energy company. Talking with customers and independent sources helps us understand as many facets of the market as possible, shapes our point of view and allows us to identify where opportunities exist in the marketplace. Our $5 billion growth program through 2015 is a prime example of acting on this point of view as we work to connect supply with demand.

IMPLEMENTING LESSONS LEARNED AND RECOGNIZING CONTRIBUTIONS

As I reflect on how we've grown, I'm amazed by our employees' accomplishments. *They're the ones* who come up with the ideas that lead to new opportunities. *They* serve our customers and work to improve our safety performance, operating efficiency and environmental responsibility efforts.

From 2006 to 2009, we completed a $2 billion growth program that set us up for the additional growth that we are experiencing today – and will experience in the future. The first milestone of that program was building the Overland Pass Pipeline, a 760-mile NGL pipeline from Opal, Wyoming, to Conway, Kansas. Before then, our growth had occurred primarily through acquisitions. When we successfully built Overland Pass and connected it to our recently acquired NGL system, it gave us a sense of confidence that we could proceed with identifying more and more growth opportunities.

RECOGNIZING CONTRIBUTORS

“Many people have contributed to the successes and growth we've experienced during the past few years.”

In February 2013, Gerald B. Smith notified us that he will resign from our board of directors in May. Gerald's involvement with the partnership dates back to 1994, when it was called Northern Border Partners. When ONEOK became the sole general partner and changed the partnership's name to ONEOK Partners in 2006, Gerald joined our board. His strong financial background has served us well during his tenure. I will miss his guidance and presence, both personally and professionally.

I also want to recognize Shelby E. Odell, who retired from our board of directors in August 2012 after serving for three years and reaching the mandatory retirement age for our board members. Shelby's deep knowledge and four decades of experience in the natural gas liquids industry proved invaluable to the partnership as we grew our NGL business during his time on our board. Thank you, Shelby, for your encouragement and leadership.

John W. Gibson
Chairman and Chief Executive Officer
March 7, 2013

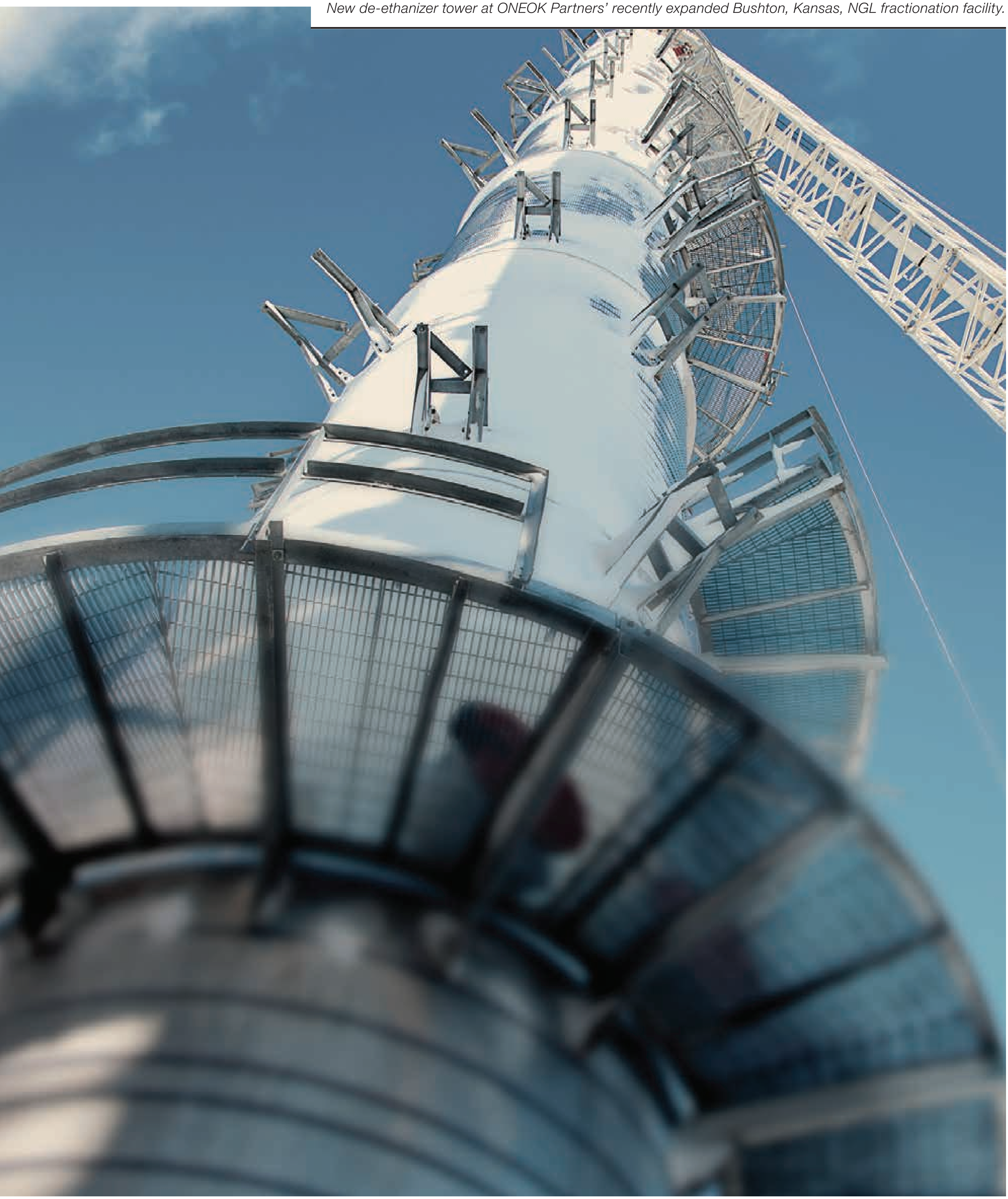
Since then, we've made progress in project execution – applying what we learned from that initial growth program to our current one.

For example, we learned how right-of-way acquisition, regulatory challenges and securing equipment, materials and environmental permits can negatively impact a project if not properly managed. Our ability to complete projects on time and on budget affects how we meet our commitments to customers and investors, and how they measure our performance. If you spend too much money or don't finish on schedule when building a natural gas processing plant or NGL pipeline, you let down those customers who depend on the asset. I'm pleased that each project in our current $5 billion growth program is currently on time and on budget. And this earned reputation for completing projects as expected – for doing what we say we're going to do – has inspired confidence from our customers. We're fortunate not to be sitting on the sidelines and watching this midstream growth take place. We're a key player, making it happen.

2012 was a year of continued progress as we achieved milestones in our growth projects, grew our capabilities to better serve our customers and continued our commitment of increasing value to you, our unitholders. I look forward to continuing this progress through the remainder of 2013 and beyond.

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

New de-ethanizer tower at ONEOK Partners' recently expanded Bushton, Kansas, NGL fractionation facility.



"BUILDING ASSETS TO BETTER SERVE CUSTOMERS"

MORE THAN $2 BILLION IN NEW PROJECTS IN THIS SEGMENT THROUGH 2015 WILL INCREASE NATURAL GAS VOLUMES ON OUR SYSTEMS.

ONEOK Partners' Garden Creek natural gas processing facility in western North Dakota.

NATURAL GAS GATHERING AND PROCESSING

Our natural gas gathering and processing segment's more than $2 billion growth program through 2015 includes the construction of six new natural gas processing facilities – five in western North Dakota in the Williston Basin and another in western Oklahoma in the Cana-Woodford Shale.

From December 2011 to early 2013, we completed three of these natural gas processing plants in western North Dakota. As a result of the plants completed in late 2011 and 2012, this segment's 2012 operating income increased by more than 15 percent, compared with 2011, to more than $210 million. We connected our gathering systems to more wells, and our natural gas volumes gathered increased by almost 10 percent. Natural gas volumes processed from our natural gas processing facilities increased by more than 20 percent.

Operating Income
Millions of Dollars

$210.4 | 2012

$180.6 | 2011

$153.6 | 2010

Variances:

(2012 vs. 2011)

- **$131.5 million increase due to volume growth in the Williston Basin** from the completion of the Garden Creek and Stateline I natural gas processing plants and increased well connections, which resulted in higher natural gas volumes gathered, compressed, processed, transported and sold, and higher fees;
- **$38.1 million decrease due primarily to higher compression costs** and less favorable contract terms associated with volume growth in the Williston Basin;
- **$31.4 million decrease from lower net realized natural gas and NGL prices,** particularly ethane and propane;
- **$5.9 million decrease from lower natural gas volumes gathered in the Powder River Basin** as a result of continued production declines;
- **$10.3 million increase in operating costs** primarily due to higher materials, supplies and outside services expenses, and higher property taxes; and
- **$14.7 million increase in depreciation and amortization.**

Our more than 17,000 miles of natural gas gathering pipelines and 16 natural gas processing plants serve a wide range of producers in six basins in the Rockies and Mid-Continent regions, providing nondiscretionary services that include the gathering and processing of natural gas produced from crude oil and natural gas wells.

CONTINUING GROWTH

Through 2015, we expect to invest $2.1 billion to $2.3 billion in this segment – including $1.7 billion to $1.9 billion in the Williston Basin and nearly $400 million in the Mid-Continent – to continue building natural gas infrastructure to accommodate increased production.

Most of these investments are in the Williston Basin, located in western North Dakota and eastern Montana, where we are the largest independent operator of natural gas gathering and processing facilities, with a natural gas gathering system of more than 5,000 miles and more than 3 million acres where production is dedicated to our systems.

Producers there are focused on the Bakken Shale and Three Forks formations, which are some of North America's largest crude-oil resource plays, yielding both crude oil and natural gas liquids (NGL)-rich natural gas. According to the North Dakota Industrial Commission, crude-oil production in the Williston Basin is expected to exceed 1 million barrels per day (bpd) over the next several years, and the natural gas produced in association with crude oil is expected to exceed 1 billion cubic feet per day.

In September 2012, we finished our Stateline I natural gas processing plant in western North Dakota, and our Garden Creek plant was completed there in late 2011. The Stateline II plant began operating in the first quarter 2013, and we've announced two additional plants in the region – the Garden Creek II and III plants – that are expected to be completed during the third quarter 2014 and first quarter 2015, respectively.

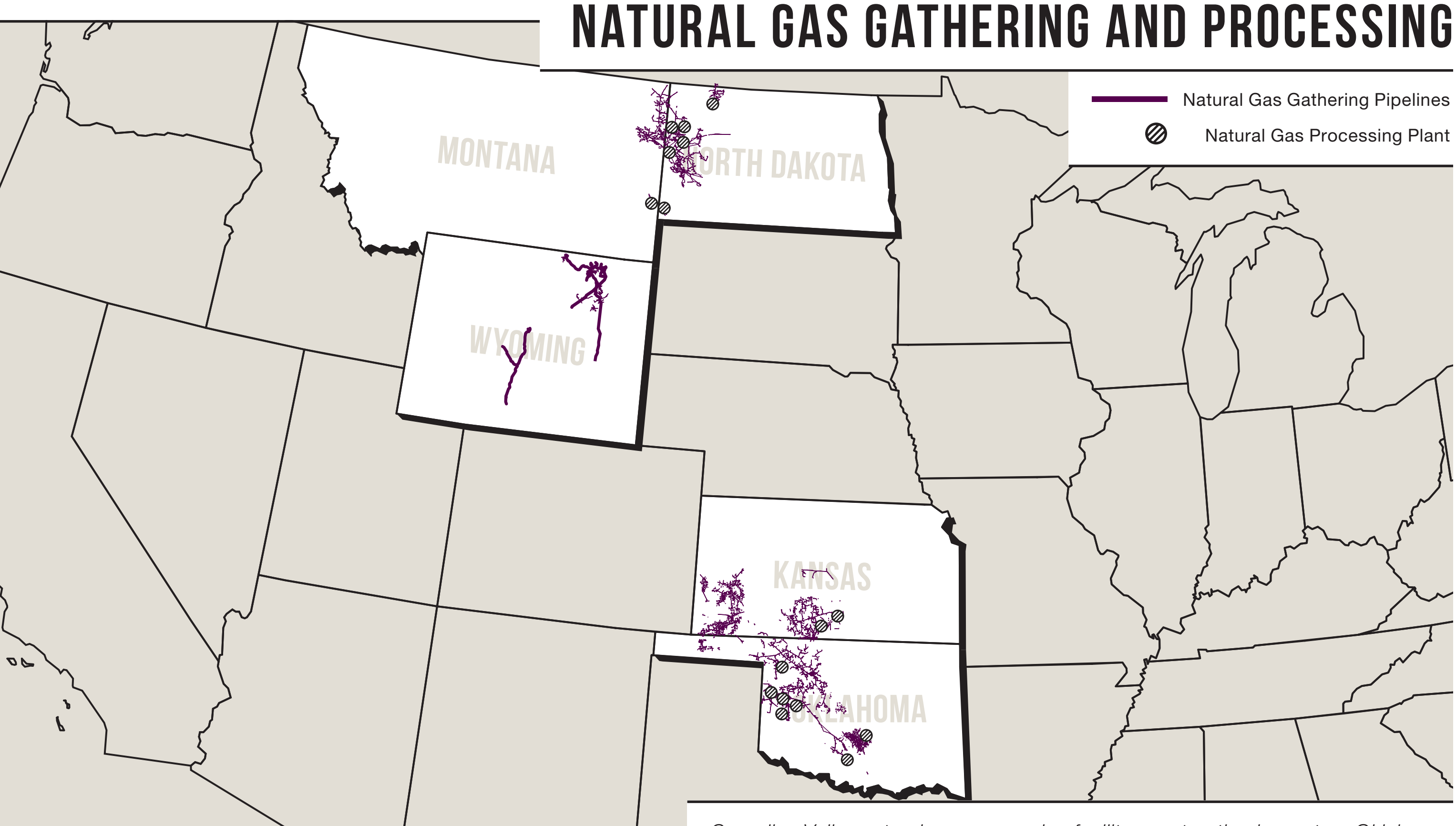
A new 270-mile natural gas gathering system in Divide County, North Dakota, that will gather and deliver natural gas to our Stateline II plant also is expected to be completed later this year. The combined natural gas processing capacity of our Williston Basin natural gas processing facilities will be more than 600 million cubic feet per day (MMcf/d) when completed, more than six times what it was in 2008.

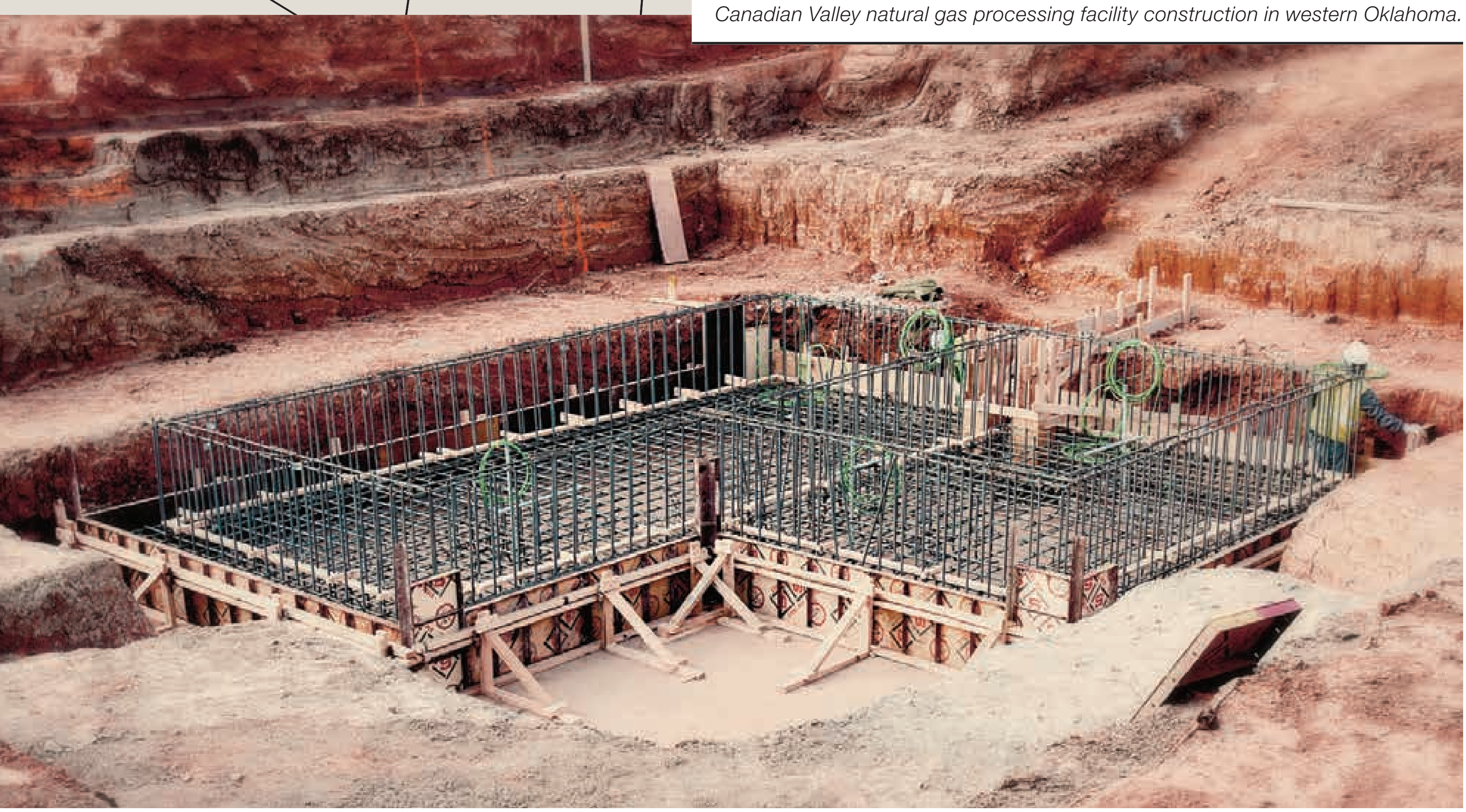
In July 2012, we announced a $340 million to $360 million natural gas processing plant, the Canadian Valley plant, in the Cana-Woodford Shale in western Oklahoma. Following its expected completion during the first quarter 2014, the 200-MMcf/d plant will be our largest natural gas processing facility.

Also included in this segment's growth program are investments for numerous new well connections, and upgrades and expansions to existing infrastructure. Our natural gas gathering and processing segment's planned capital expenditures for 2013 are more than $1 billion, primarily for the growth projects mentioned above.

(See page 22 of this report for more information on our growth projects.)

NATURAL GAS GATHERING AND PROCESSING

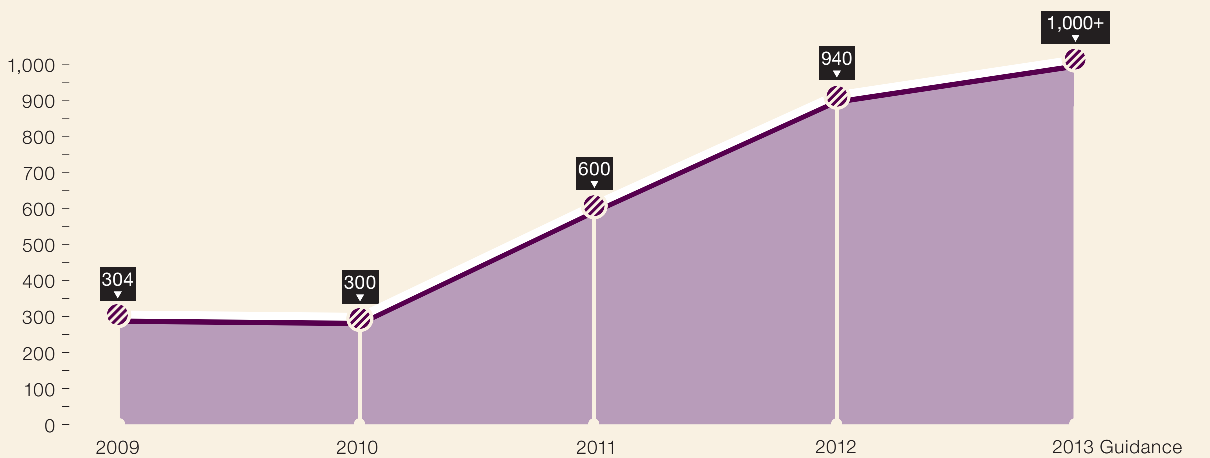




Canadian Valley natural gas processing facility construction in western Oklahoma.

Garden Creek natural gas processing plant in western North Dakota.

WELL CONNECTIONS



ADDING CONNECTIONS

In 2012, we connected approximately 940 new wells to our natural gas systems, a 55 percent increase over the nearly 600 wells connected in 2011. That number is expected to grow to more than 1,000 in 2013, as our Stateline II plant goes into service and our Divide County natural gas gathering system is completed in northwest North Dakota. Since 2007, we have connected nearly 3,000 new wells and have a backlog of almost 1,000 wells in various stages of permitting, drilling or completion to be connected to our natural gas gathering systems over the next 12 to 18 months.

With these new well connections and new natural gas processing plants in the Williston Basin adding natural gas supply to our systems, natural gas volumes (on a million British thermal unit basis) gathered in the Williston Basin are expected to increase to almost 50 percent of total volumes in 2015, compared with nearly 30 percent in 2012.

Across our six-basin operating area, 2013 natural gas volumes processed are expected to increase by nearly 30 percent, and natural gas volumes gathered are expected to increase by more than 20 percent, compared with 2012.

PUTTING OUT FLARES

The production of crude oil is the primary economic driver behind Williston Basin drilling activity – natural gas and NGLs are byproducts, accounting for less than 10 percent of the value of production there.

In 2012, the state of North Dakota estimated that more than 30 percent of the natural gas produced in the state was flared because economic incentives to drill and complete wells by producers have outpaced the construction of natural gas gathering and processing infrastructure. Our new natural gas processing plants will reduce this flaring and provide producers with essential natural gas gathering and processing infrastructure to bring natural gas and NGLs to market.

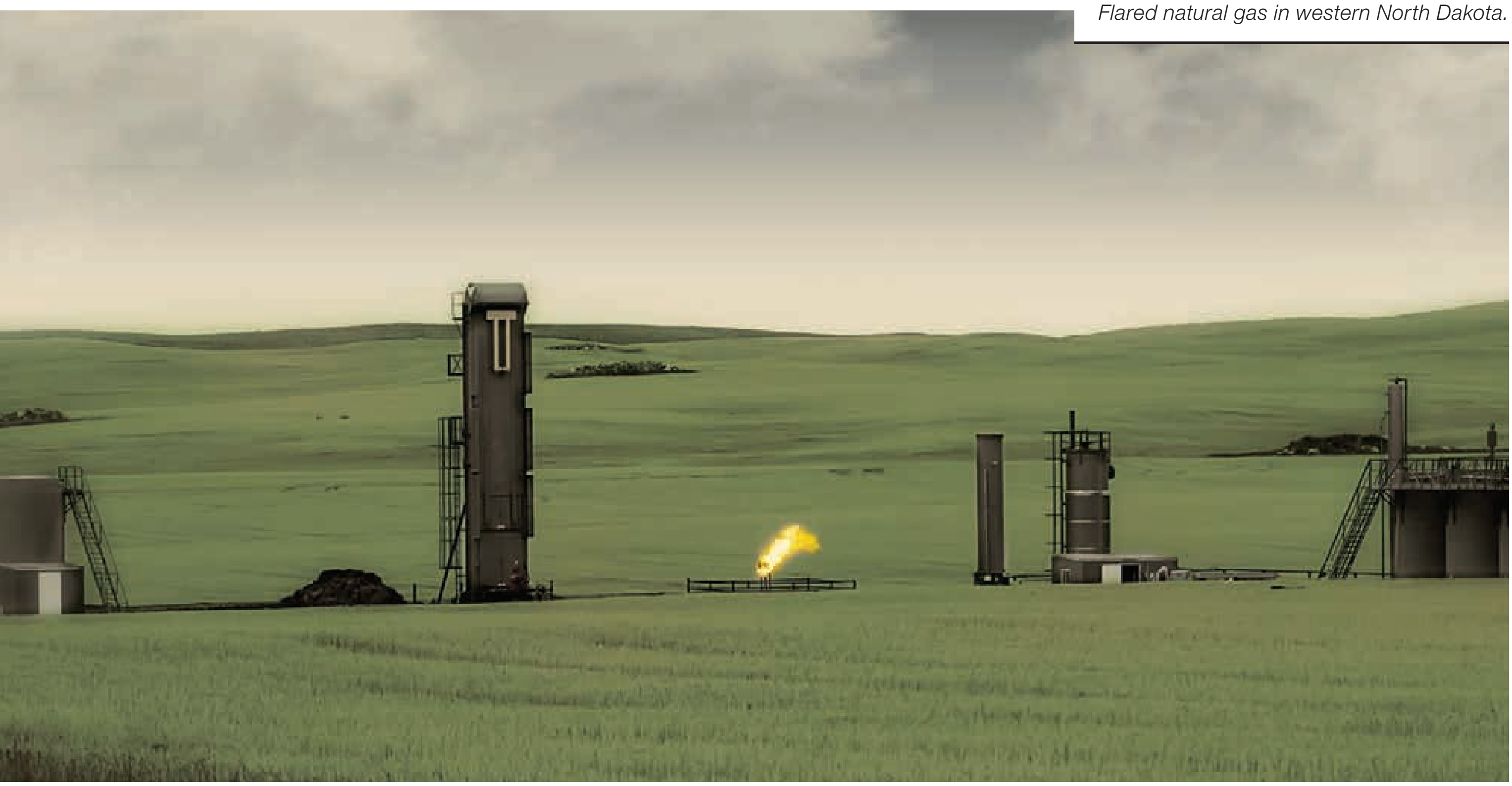
By early 2015, we expect to have built five new natural gas processing plants and related infrastructure in western North Dakota to gather and process natural gas that otherwise would have been flared or not produced – creating a win-win situation for the environment, regulators and our producers and customers.

INTEGRATING OUR ASSETS

In liquids-rich shale plays, such as the Bakken Shale and Three Forks formations, the natural gas produced in association with crude oil must be processed before it can be delivered to the marketplace. This is where our natural gas processing plants figure prominently, separating the natural gas into pipeline-quality natural gas and unfractionated NGLs that require further processing to create marketable products such as ethane, propane, butane and natural gasoline.

Additional NGL infrastructure is needed to handle the increased NGL supplies coming from our plants and those of third parties, not only in the Williston Basin but also in the Mid-Continent. Our natural gas liquids business is investing up to $800 million of its planned $2.6 billion to $3.0 billion investments through 2015 for projects related to the Williston Basin region, including the construction of the Bakken NGL Pipeline, the first unfractionated NGL pipeline to serve the Williston Basin and provide producers there with essential NGL transportation capacity. *(See page 17 of this report for more information on our natural gas liquids business.)*

Flared natural gas in western North Dakota.



ONEOK Partners’ natural gas intrastate pipelines connect to a natural gas processing plant near Woodward, Oklahoma.

NATURAL GAS PIPELINES

Our natural gas pipelines segment provides natural gas transportation and storage to customers across the natural gas value chain, predominantly local natural gas distribution companies, electric-power generation plants, producers and large industrial customers.

Utility customers and shippers continue to place an importance and value on the performance and dependability of firm-capacity natural gas transportation and storage. We provide firm services through long-term, fee-based contracts on our network of more than 6,500 miles of interstate and intrastate pipelines and approximately 52 billion cubic feet (Bcf) of storage capacity.

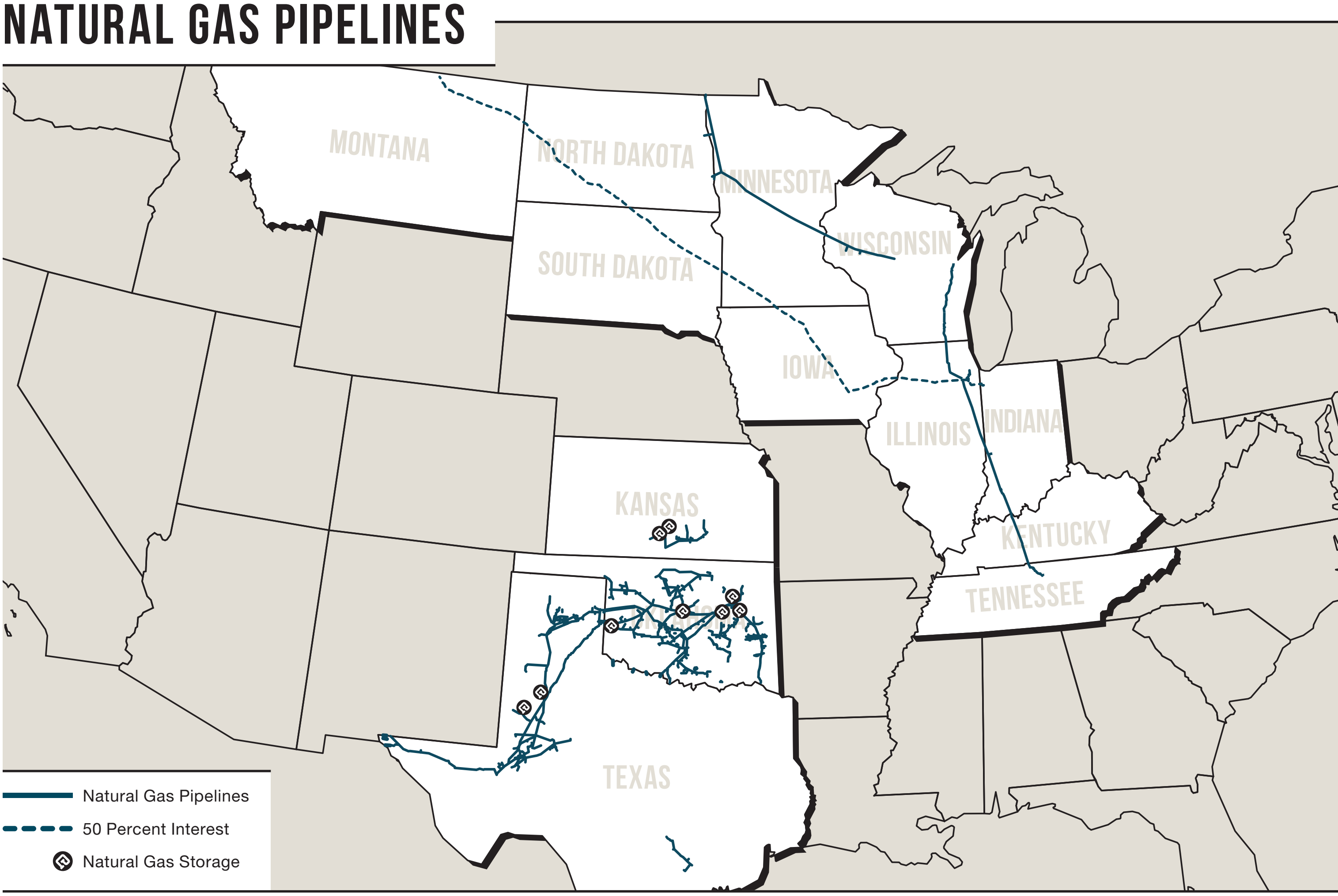
Operating Income
Millions of Dollars

Variances:

(2012 vs. 2011)

- **$3.3 million increase from higher contracted capacity on its intrastate natural gas pipelines,** offset partially by lower negotiated rates on Midwestern Gas Transmission;
- **$1.0 million decrease from lower natural gas prices** on its net retained fuel position;
- **$5.7 million pre-tax gain** on the sale of a natural gas pipeline lateral; and
- **Decreased employee-related costs** associated with incentive and benefit plans.

NATURAL GAS PIPELINES



The natural gas pipelines segment remains an important part of ONEOK Partners' diverse midstream business platform, producing stable operating income and strong cash flows. 2012 operating income for this segment increased more than 10 percent, compared with 2011, to more than $140 million. 2012 equity income, primarily from our 50 percent ownership of Northern Border Pipeline, was more than $70 million, a 5 percent decrease compared with 2011.

We operate natural gas pipelines that transport natural gas through North Dakota, Minnesota, Wisconsin, Illinois, Indiana, Kentucky, Tennessee, Oklahoma, Texas, Kansas and New Mexico, and provide a variety of natural gas storage services for customers in Oklahoma, Texas and Kansas through our wholly owned storage assets.

Earnings in this segment are predominantly fee-based, and 89 percent of our natural gas pipeline transportation capacity and 100 percent of our natural gas storage capacity are contracted.

CREATING OPTIONS FOR PRODUCERS

Shale-play developments have changed the natural gas supply landscape throughout the United States, resulting in directional changes in the flow of natural gas across the country's pipeline grid and narrowing transportation differentials between locations – the price difference between origination and receipt points. As a result, markets now have greater access to abundant lower-cost natural gas supply from these developing basins. Producers in our intrastate natural gas pipelines operating areas are drilling actively in the prolific Mississippian Lime, Cana-Woodford, Granite Wash, Delaware and Cline shales. These developments have led to the construction of numerous natural gas processing plants, where our pipelines are well-positioned to provide natural gas transportation infrastructure.

Likewise, producers in the Utica and Marcellus shales are exploring alternative methods of transporting natural gas to new markets, including the large Chicago market. Our natural gas pipelines are located strategically to provide utility customers and producers with options to transport their natural gas to nearby markets, with the added flexibility to use interconnected third-party storage to meet their changing needs.

SUPPLYING ELECTRIC-GENERATION PLANTS

The combination of increased emissions regulations on coal-fired, electric-power generation plants and the continued abundance of low-priced natural gas has caused many electric utilities to turn to natural gas to produce electricity for their customers. Either by conversion or new construction, electric-power generation companies are looking to more affordable, cleaner-burning natural gas to fuel their power plants. We are well-positioned to take advantage of this trend, with approximately 35 existing coal-fired, electric-power generation plants representing more than 26,000 megawatts of capacity within 20 miles of our natural gas pipelines. We can provide the flexible services electric utilities need to successfully convert their coal-fired plants to natural gas. To get the natural gas supply to operate their electric-power generation plants and serve their residential and commercial customers, these electric utilities will look to companies like ours to contract for capacity on our regulated natural gas pipelines.

PROVIDING ESSENTIAL TRANSPORTATION CAPACITY

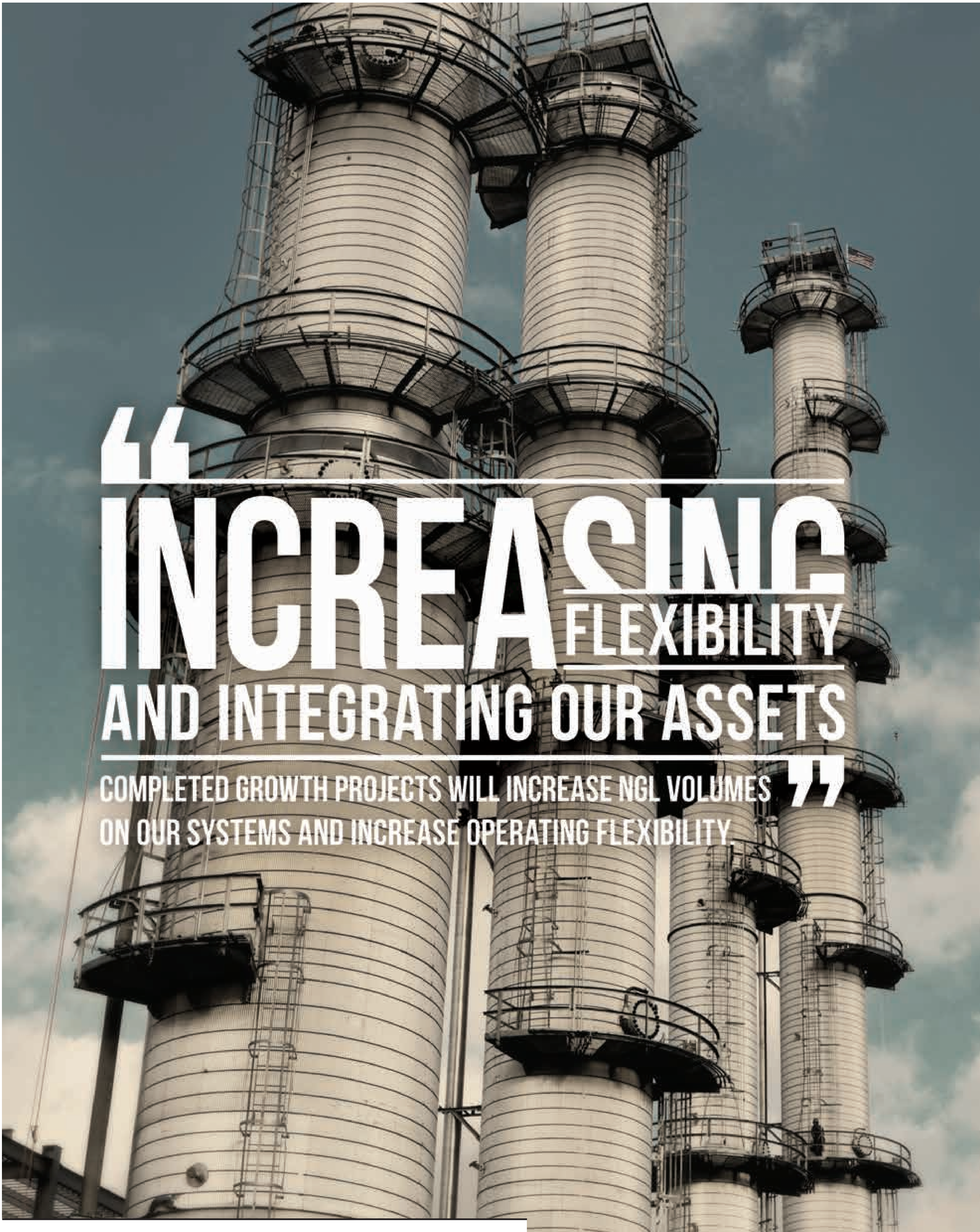
We own a 50 percent interest in Northern Border Pipeline, which transports Canadian natural gas to Midwest markets. Northern Border also provides essential transportation capacity for natural gas produced in the Williston Basin, including pipeline-quality natural gas delivered from ONEOK Partners' extensive natural gas gathering and processing system in western North Dakota and eastern Montana. *(For more information on our natural gas gathering and processing business, see page 7 of this report.)*

In January 2013, the Federal Energy Regulatory Commission approved the Northern Border Pipeline rate case settlement negotiated with shippers. The new long-term transportation rates are approximately 11 percent lower than the previous rates.

Natural gas intrastate pipelines near Woodward, Oklahoma.

“INCREASING FLEXIBILITY AND INTEGRATING OUR ASSETS

COMPLETED GROWTH PROJECTS WILL INCREASE NGL VOLUMES ON OUR SYSTEMS AND INCREASE OPERATING FLEXIBILITY.”



ONEOK Partners’ MB-2 NGL fractionator under construction in Mont Belvieu, Texas.

NATURAL GAS LIQUIDS

Our natural gas liquids business – one of the nation's largest – continued its solid performance in 2012, while progressing with a $3 billion growth program that, when completed in 2015, will increase our natural gas liquids (NGL) gathering and fractionation capabilities and create added operating flexibility.

2012 operating income in this segment was nearly $610 million, a decrease of 3 percent compared with 2011's record performance. This segment benefited from higher NGL volumes gathered and fractionated as a result of completed capital growth projects in the Mid-Continent but was affected by narrower NGL location price differentials, compared with historically wide differentials in 2011, and less transportation capacity available for these optimization activities due to an increasing portion of transportation capacity between Conway, Kansas, and Mont Belvieu, Texas, now being used to produce fee-based earnings.

Operating Income

Millions of Dollars

$608.2 | 2012

$628.6 | 2011

$272.3 | 2010

Variances:

(2012 vs. 2011)

- **$101.5 million increase from higher NGL volumes gathered and fractionated** related to the completion of certain growth projects, and higher fees from contract renegotiations for its NGL exchange-services activities;
- **$13.1 million increase due to higher NGL storage margins** as a result of favorable contract renegotiations;
- **$91.2 million decrease in optimization and marketing margins**, which resulted from a $94.6 million decrease from narrower NGL location price differentials and less transportation capacity available for optimization activities; an increasing portion of its transportation capacity between the Conway, Kansas, and Mont Belvieu, Texas, NGL market centers now is utilized by its exchange-services activities to produce fee-based earnings. This decrease was offset partially by a $3.5 million increase in its marketing activities, which benefited from higher NGL truck and rail volumes;
- **$4.5 million decrease due to the impact of operational measurement losses;**
- **$3.4 million decrease due to lower isomerization margins** from lower isomerization volumes;
- **$24.9 million increase** in operating costs; and
- **$10.4 million increase in depreciation and amortization.**

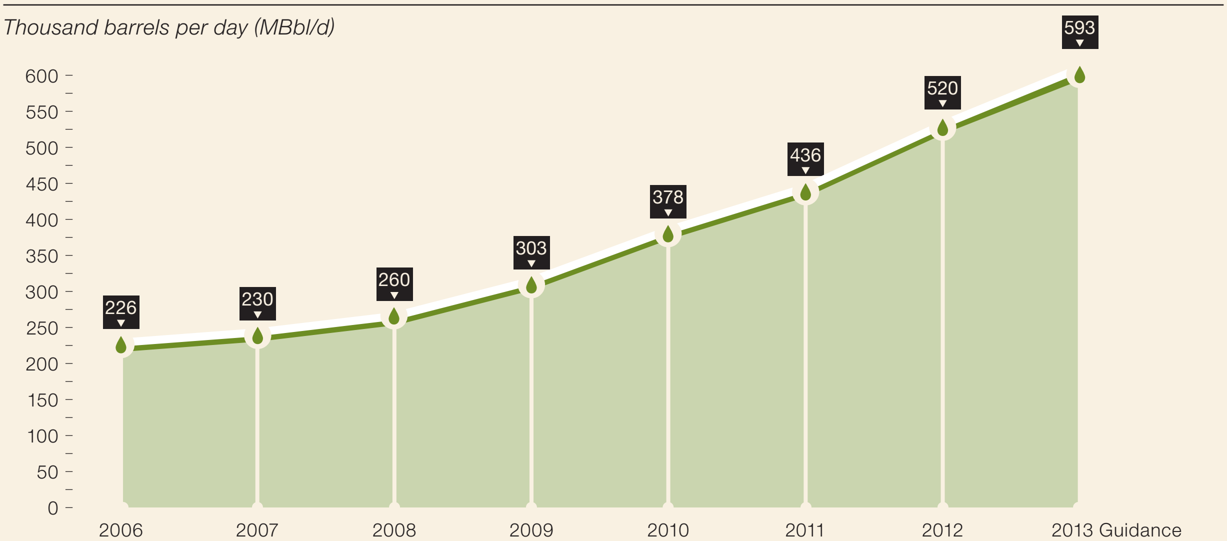
UNDERSTANDING NGL SUPPLY AND DEMAND

Developing a forward-looking point of view on natural gas, NGLs and crude-oil supply and demand is important when we make decisions about how we're going to invest. In recent years, technological advancements in horizontal drilling and well stimulation have made natural gas and NGLs easier to access, thus increasing supplies and making them more affordable. Since 2006, our NGL gathering volumes have more than doubled, and our NGL fractionation volumes have increased by more than 80 percent through 2012. We estimate that our 2013 NGL gathering volumes will increase by almost 15 percent, and our NGL fractionation volumes will grow by nearly 10 percent as a result of completing several growth projects.

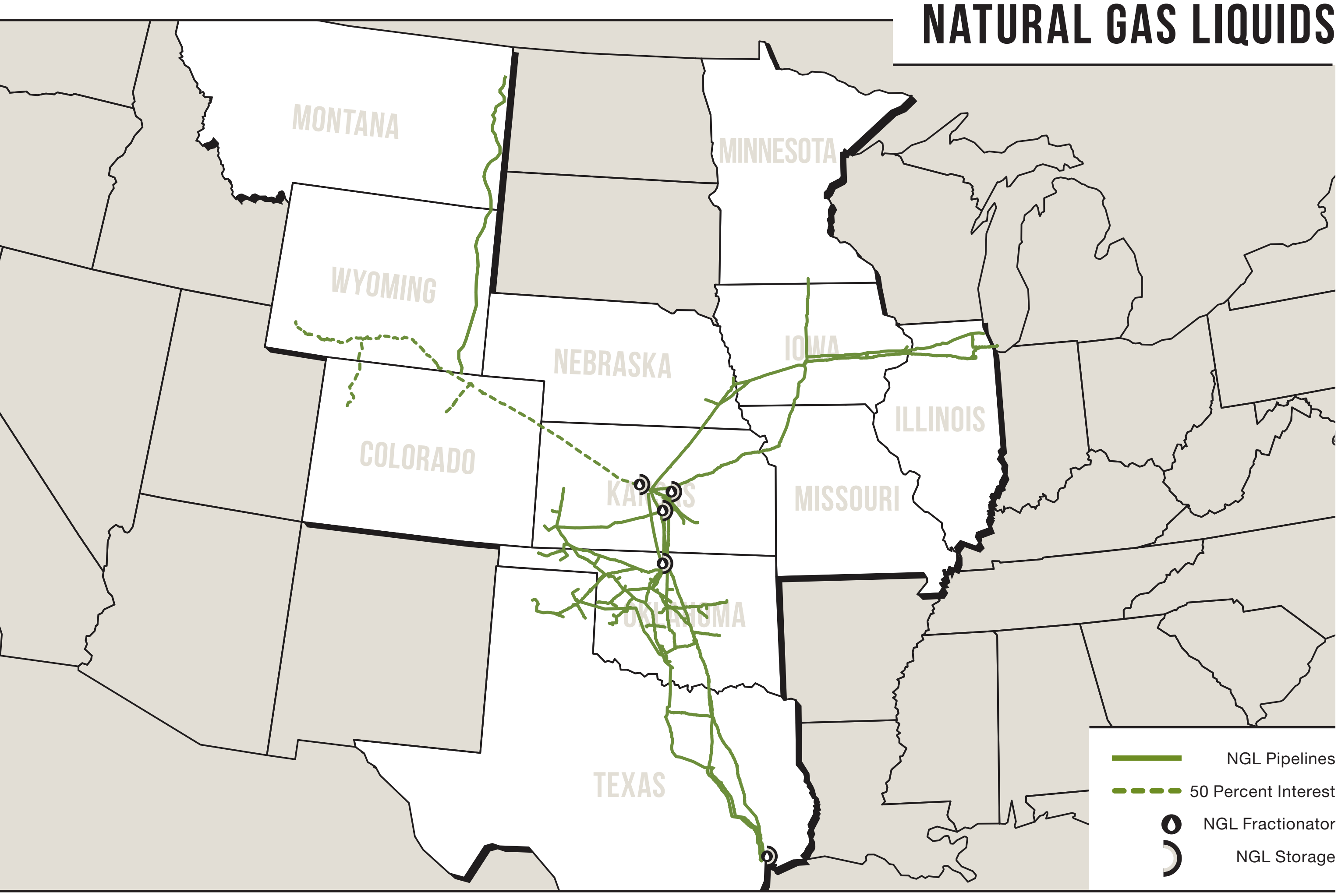
The demand for NGL purity products remains strong as petrochemical companies continue using lower cost NGLs, such as ethane and propane, for feedstocks over more expensive crude-oil-based alternatives. This has resulted in several petrochemical companies announcing expansions or new facilities in the Gulf Coast region. Demand for ethane is forecasted to increase by more than 700,000 barrels per day (bpd) by 2017. Demand for propane also is expected to increase as new export facilities on the Gulf Coast come on line in 2013.

NATURAL GAS LIQUIDS GATHERING VOLUME GROWTH

Thousand barrels per day (MBbl/d)



NATURAL GAS LIQUIDS



We provide nondiscretionary NGL gathering, fractionation, transportation, storage and marketing services that enable NGL producers to convert their unfractionated barrels into NGL purity products and deliver them to wholesalers, petrochemical facilities and refineries in the Mid-Continent, upper Midwest, including Chicago, 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 hubs.

CONNECTING THE WILLISTON BASIN TO OUR SYSTEMS

The Bakken NGL Pipeline – the first pipeline to provide unfractionated NGL transportation capacity out of the Williston Basin – was completed in March 2013. The Bakken NGL Pipeline is a $450 million to $550 million, 600-mile pipeline with the capacity to transport 60,000 bpd of unfractionated NGLs from our natural gas gathering and processing plants in the Williston Basin to an interconnection with our 50 percent-owned Overland Pass Pipeline in northern Colorado, and 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 – an example of the value of our integrated system at work.

Both our Bushton, Kansas, NGL fractionation facility and the Overland Pass Pipeline recently were expanded to handle the increased volumes from the Williston Basin. Due to growing demand for NGL transportation capacity from Williston Basin producers, we are installing additional pump stations on the Bakken NGL Pipeline to increase its capacity to 135,000 bpd from an initial capacity of 60,000 bpd. This expansion is expected to be completed in the third quarter 2014.

Construction at the MB-2 NGL fractionator in Mont Belvieu, Texas.

In early 2013, we announced a new, 95-mile NGL pipeline that will connect our Hutchinson, Kansas, NGL facilities to similar ones in Medford, Oklahoma, and modifications to our existing NGL fractionation and storage facilities at Hutchinson. Expected to be completed during the first quarter 2015, the new pipeline and modified NGL infrastructure are designed to handle additional NGLs added to our system from the Williston Basin.

INCREASING OPERATIONAL FLEXIBILITY AND GULF COAST FRACTIONATION CAPACITY

Construction of our Sterling III NGL Pipeline, a 540-mile pipeline with the capacity to transport 193,000 bpd of either unfractionated NGLs or purity products, is expected to begin this summer and be completed in late 2013. Sterling III will be our fourth NGL pipeline to connect our Mid-Continent NGL infrastructure to similar facilities on the Gulf Coast in Mont Belvieu, Texas. It will parallel our existing Sterling I and Sterling II NGL distribution pipelines, which are being reconfigured to transport either unfractionated NGLs or purity products. The estimated cost for the new Sterling III Pipeline and these reconfigurations is $610 million to $810 million.

We currently own an 80 percent interest in MB-1, a 160,000-bpd NGL fractionator, and we have a long-term, third-party fractionation-services agreement for an additional 60,000 bpd of fractionation capacity at Mont Belvieu, Texas. To meet the growing demand from petrochemical companies for ethane and propane as feedstocks, we will expand our Gulf Coast NGL fractionation capacity by building two new 75,000-bpd NGL fractionators near our NGL storage facility at Mont Belvieu – MB-2 and MB-3 – both of which are

Bakken NGL Pipeline construction in northeast Wyoming.

backed by contracts with producers and processors. MB-2 is expected to be completed by mid-2013 at an estimated cost of $300 million to $390 million, and MB-3 is expected to be completed during the fourth quarter 2014 at an estimated cost of $375 million to $415 million. In addition, a new, $45 million ethane/propane (E/P) splitter will be installed at our Mont Belvieu NGL storage facility that will split E/P mix into purity ethane to meet the growing needs of petrochemical customers. The facility is expected to be completed in the second quarter 2014.

EXPANDING OUR REACH

In April 2012, we completed a $220 million expansion of our Mid-Continent NGL infrastructure in the Cana-Woodford Shale and Granite Wash production areas of western Oklahoma and the Texas Panhandle by constructing 230 miles of NGL gathering systems that are connected to three new and three expanded, third-party natural gas processing plants. These connections added 75,000 to 80,000 bpd of unfractionated NGLs to our NGL system, which delivers NGLs on our Arbuckle Pipeline to our Mont Belvieu NGL fractionation and storage facilities, as well as to other fractionators. To accommodate these increased NGLs, the Arbuckle Pipeline was expanded by 60,000 bpd to 240,000 bpd in April 2012.

NOT PROCEEDING WITH BAKKEN CRUDE EXPRESS PIPELINE

Despite the robust outlook for crude-oil supply growth in the Williston Basin, we did not receive sufficient long-term binding transportation commitments needed to construct the Bakken Crude Express Pipeline. As a result, in late 2012 we announced that we would not proceed with plans to construct the pipeline.

GROWTH PROGRAM TIMELINE

2012 was the second year of our most recent internally generated capital-growth program, which includes investments of $4.7 billion to $5.3 billion through 2015 for natural gas and natural gas liquids (NGL) infrastructure projects that will enhance our midstream capabilities and enable us to better serve producers and customers.

2011

__Sterling I Pipeline expansion__ – increased capacity by 15,000 barrels per day (bpd) NGLs.

__Garden Creek plant__ – 100-million cubic feet per day (MMcf/d) natural gas processing facility in the Williston Basin in North Dakota.

2012

__Arbuckle Pipeline expansion__ – increased capacity to 240,000 bpd of NGLs.

__Mid-Continent NGL gathering system expansion__ – approximately 230 miles of NGL gathering pipelines in the Cana-Woodford and Granite Wash areas.

__Stateline I plant__ – 100-MMcf/d natural gas processing facility in the Williston Basin in North Dakota.

__Bushton NGL fractionator expansion__ – increased NGL fractionation capacity by 60,000 bpd to 210,000 bpd.

2013

__Overland Pass Pipeline (50 percent-owned) expansion__ – increased capacity to 255,000 bpd of NGLs.

__Stateline II plant__ – 100-MMcf/d natural gas processing facility in the Williston Basin in North Dakota.

__Bakken NGL Pipeline__ – 600-mile NGL pipeline that has the capability to transport 60,000 bpd of unfractionated NGLs from the Williston Basin to an existing pipeline in northern Colorado.

Completed Growth Project

Announced Growth Project

As of March 2013

Divide County gathering system – *approximately 270-mile natural gas gathering system and related infrastructure in Divide County, North Dakota.*

Sterling III Pipeline – *540-mile NGL pipeline capable of transporting 193,000 bpd of either unfractionated NGLs or purity products from north-central Oklahoma to Mont Belvieu, Texas.*

Reconfiguration of Sterling I and II Pipelines – *to transport either unfractionated NGLs or NGL purity products.*

MB-3 NGL fractionator – *75,000-bpd NGL fractionator at Mont Belvieu, Texas, and related infrastructure.*

2014

2015

2016

Garden Creek II plant – *100-MMcf/d natural gas processing facility in the Williston Basin in North Dakota.*

Bakken NGL Pipeline expansion – *will increase capacity to 135,000 bpd from 60,000 bpd.*

A 95-mile NGL pipeline – *will connect NGL fractionation and storage facilities in Hutchinson, Kansas, to similar facilities in Medford, Oklahoma.*

Hutchinson NGL fractionator modifications – *to accommodate additional unfractionated NGLs produced in the Williston Basin.*

Garden Creek III plant – *100-MMcf/d-natural gas processing facility in the Williston Basin in North Dakota.*

MB-2 NGL fractionator – *75,000-bpd NGL fractionator at Mont Belvieu, Texas.*

Ethane/Propane (E/P) splitter – *40,000-bpd E/P splitter at Mont Belvieu, Texas.*

Canadian Valley plant – *200-MMcf/d natural gas processing facility in the Cana-Woodford Shale in Oklahoma.*

Note: *In late 2012, we announced that due to insufficient long-term transportation commitments, we will not proceed with the Bakken Crude Express Pipeline.*

INCREASING

FINANCIAL OVERVIEW

Through 2012, we've increased our cash distributions, an important measure of progress, by more than 70 percent since April 2006, when a wholly owned subsidiary of ONEOK, Inc. became the sole general partner.

We expect to increase total unitholder distributions by an annual average of 8 to 12 percent between 2012 and 2015, subject to board approval.

DISTRIBUTIONS

FINANCING OUR GROWTH

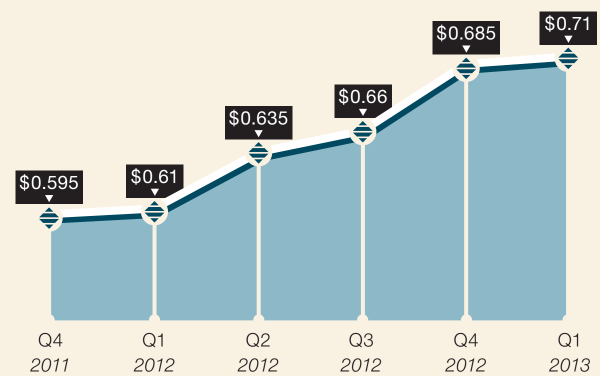
Overall, 2012 cash distributions paid to unitholders increased 11 percent, compared with 2011. The growth we're experiencing allowed us to increase distributions to our unitholders by 1.5 cents per unit in the first quarter 2012. We then increased cash distributions to our unitholders by 2.5 cents per unit per quarter for the second, third and fourth quarters 2012.

To finance our $4.7 billion to $5.3 billion in growth projects, we are using a combination of debt and equity. We remain committed to maintaining our investment-grade credit rating and a healthy balance sheet. At year-end 2012, the partnership's long-term debt-to-capitalization ratio was 52 percent. Our long-term goal is a capital structure of 50 percent debt and 50 percent equity as the current growth projects are completed. Our debt-to-adjusted-EBITDA (earnings before interest, taxes, depreciation and amortization) ratio, as defined in our credit agreement, at year-end was 3 to 1. We are in compliance with all covenants required by our lenders, which allows us full access to our $1.2 billion credit facility.

We completed an equity offering and private placement in March 2012, issuing 16 million common units and generating proceeds of $920 million. We used a portion of these proceeds to pay off commercial-paper loans and repay $350 million in senior notes. Our general partner, ONEOK, purchased 8 million of these issued common units, further demonstrating strong general partner support that

DISTRIBUTION GROWTH

ONEOK Partners quarterly distributions paid per unit



gives us the ability to access two balance sheets to finance our growth.

In September 2012, we issued $1.3 billion in senior notes, using these proceeds to pay off commercial-paper loans and prefund part of our growth projects.

We also entered into an equity distribution agreement to offer, from time to time, common units representing limited partner interests up to an aggregate amount of $300 million. We intend to use the net proceeds from this program for general partnership purposes, which may include, among other things, repayment of debt, working capital and capital expenditures.

EMPHASIZING

SAFETY AND ENVIRONMENTAL RESPONSIBILITY

“WE ARE COMMITTED TO OPERATING OUR ASSETS SAFELY AND IN AN ENVIRONMENTALLY RESPONSIBLE MANNER, AND GIVING BACK TO THE COMMUNITIES WHERE WE OPERATE.”

An employee conducts a routine inspection at the Bushton, Kansas, NGL fractionator.

Our commitment to corporate responsibility remains strong and continues to be at the forefront of everything we do. From operating safely and environmentally responsibly to investing time and resources in our communities, we focus on doing what is right for our employees, customers and communities.

A few highlights from 2012 include:

- Establishing an Environment, Safety and Health (ESH) Management System Framework companywide;
- Decreasing both our Total Recordable Incident Rate (TRIR) and Preventable Vehicle Incident Rate (PVIR) by approximately 13 percent, compared with our 2011 performance;
- Contributing more than $5.3 million to support nonprofit organizations across our operating areas; and
- Our general partner receiving the first-ever Community Impact Award from the Oklahoma Business Ethics Consortium recognizing our employee-volunteer efforts and investments in local communities.

The Powered by ONE mobile exhibit has been traveling throughout our operating areas for nearly a year, educating and informing stakeholders about the company and the benefits of using natural gas and natural gas liquids.

CREATING A FRAMEWORK

In 2012, we established an ESH Management System Framework companywide that defines our ESH operating expectations, more efficiently manages ESH risks and improves our ESH performance.

All company business segments are reviewing their operations and identifying opportunities for improvement that will become the basis for establishing short-term and long-term ESH goals.

ESH achievements in 2012 included:

Safety and Health

- Operating 12 consecutive months without an Occupational Safety and Health Administration (OSHA)-recordable injury or illness in our natural gas pipelines segment.
- Finishing the year with zero agency-reportable events in our natural gas gathering and processing and natural gas pipeline segments.
- Expanding our preventive safety programs, including safety training, near-miss reporting, vehicle-safety monitoring, and risk assessment and behavior-based safety programs.

Pipeline Safety

- Conducting more than 70 internal inspections and pipeline-integrity evaluations on nearly 3,000 miles, or approximately 40 percent, of our NGL pipeline infrastructure.
- Completing more than 300 miles of internal inspections, nearly 70 miles of external-corrosion assessments and more than 200 direct examinations on natural gas transmission pipelines as part of our integrity-management program. With these inspections and previous assessments completed during the past 10 years, we have met or exceeded federal and state integrity-management program requirements.
- Completing leak detection and repair operations assessments on more than 50 percent of our natural gas gathering and processing plants.
- Conducting security vulnerability analyses and improving security procedures across all three segments.

ONEOK PARTNERS' ESH VISION

We are committed to pursuing a zero-incident culture by continuously working toward mitigating risk and eliminating incidents that may harm our employees, contractors, the public and the environment.

Note: Additional information is included in our 2011-2012 Corporate Responsibility Report, which is available on our website, www.oneokpartners.com.

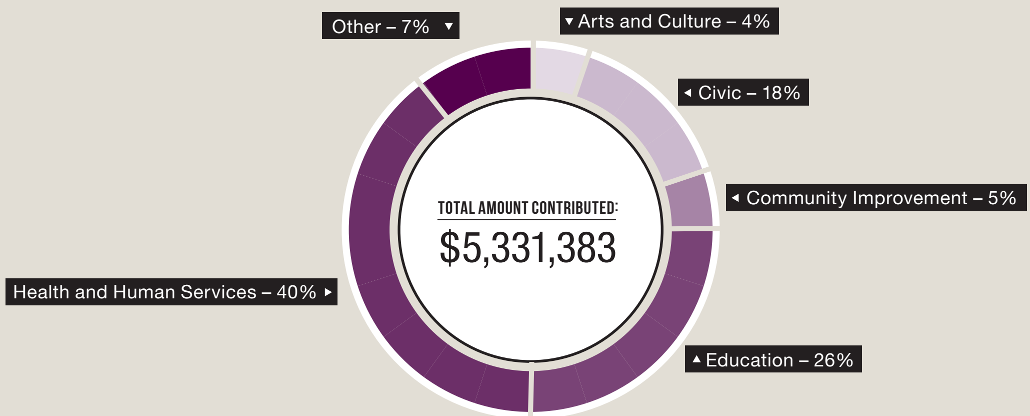
In 2012, employees volunteered more than 12,500 hours in our communities with a value of more than $270,000.*

INVESTING IN OUR COMMUNITIES

In 2012, we contributed more than $5.3 million to nonprofit organizations through the ONEOK Foundation and corporate contributions.

2012 PERCENTAGE OF GIVING BY FOCUS AREA

ONEOK Foundation** and Corporate Contributions



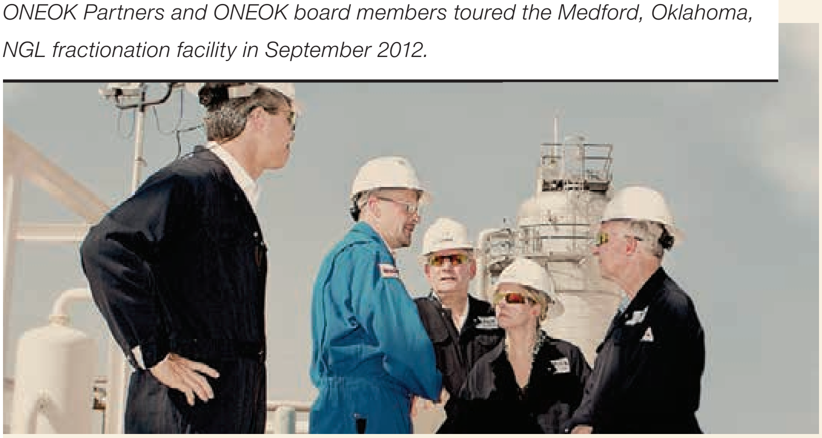
*Based on the estimated volunteer-hour value of $21.79.

**Programs administered by the ONEOK Foundation include these as well as others: Public School Foundation Matching Grants, Energy-Assistance Matching Grants and Volunteers With Energy Matching Grants.*

SOME OF THE GRANTS APPROVED IN 2012 INCLUDED:

- Plans to contribute approximately $2.2 million between now and 2016 to benefit Tulsa's historic Greenwood District, commonly referred to as "The Black Wall Street" during the early 20th century, specifically the Greenwood Cultural Center and John Hope Franklin Center for Reconciliation that honors Dr. John Hope Franklin, a great American historian and civic leader.
- $112,000 for new lab equipment at the National Energy Center of Excellence at Bismarck State College in Bismarck, North Dakota.
- $25,000 for the Sunlight Child Advocacy Center in El Dorado, Kansas, to support the building of a home for children suffering from abuse.

ONEOK Partners and ONEOK board members toured the Medford, Oklahoma, NGL fractionation facility in September 2012.



BOARD OF DIRECTORS

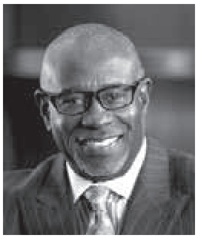
Julie H. Edwards
Former Chief Financial Officer, Southern Union Company; Former Chief Financial Officer, Frontier Oil Corporation
Houston, Texas

John W. Gibson
Chairman and Chief Executive Officer, ONEOK Partners, L.P. and ONEOK, Inc.
Tulsa, Oklahoma

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

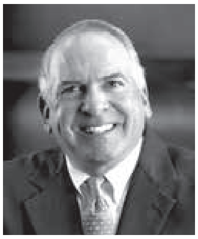
Jim W. Mogg
Retired Chairman, DCP Midstream GP, L.L.C.
Hydro, Oklahoma

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



Gerald B. Smith
Chairman and Chief Executive Officer, Smith, Graham & Company Investment Advisors L.P.
Houston, Texas

Terry K. Spencer
President, ONEOK Partners, L.P. and ONEOK, Inc.
Tulsa, Oklahoma



Craig F. Strehl
Retired Executive, Southern Union Company
Fort Worth, Texas

Gil J. Van Lunsen
Retired Managing Partner, KPMG LLP
Durango, Colorado

OFFICERS

ONEOK PARTNERS OFFICERS

John W. Gibson, 60
Chairman and Chief Executive Officer

Terry K. Spencer, 53
President

Stephen W. Lake, 49
Senior Vice President, General Counsel and Assistant Secretary

Derek S. Reiners, 41
Senior Vice President, Chief Financial Officer and Treasurer

Robert F. Martinovich, 55
Executive Vice President, Operations

Pierce H. Norton II, 52
Executive Vice President, Commercial

Dandridge L. Harrison, 59
Senior Vice President, Administrative Services and Corporate Relations

Robert S. Mareburger, 51
Senior Vice President, Corporate Planning and Development

Sheppard F. Miers III, 44
Vice President and Chief Accounting Officer

AGES AS OF DECEMBER 31, 2012

OPERATIONS

Wesley J. Christensen, 59
Senior Vice President, Operations

Geoffrey A. Sands, 50
Vice President, Natural Gas Gathering and Processing Operations

Craig A. Forsander, 48
Vice President, Natural Gas Pipeline Operations

Roger G. Thorpe, 45
Vice President, Natural Gas Liquids Operations

J. Brian Boulter, 60
Vice President, Construction Projects

COMMERCIAL

Curtis L. Dinan, 45
Senior Vice President, Natural Gas

Kevin L. Burdick, 48
Vice President, Natural Gas Gathering and Processing

J. Phillip May, 50
Vice President, Natural Gas Pipelines

Sheridan C. Swords, 43
Senior Vice President, Natural Gas Liquids

Michael L. Turner, 39
Vice President, Natural Gas Liquids Gathering and Fractionation

John D. O’Dell, 50
Vice President, Natural Gas Liquids Optimization

FORM 10-K

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, 2012.
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, 2012, was $6.8 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 19, 2013
Common units	146,827,354 units
Class B units	72,988,252 units

DOCUMENTS INCORPORATED BY REFERENCE: None.

ONEOK PARTNERS, L.P.
2012 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, 2012
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
Bighorn Gas Gathering	Bighorn Gas Gathering, L.L.C.
Btu(s)	British thermal units, a measure of the amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit
Bushton Plant	Bushton Natural Gas Processing and Fractionation Plant
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
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010
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
Fort Union Gas Gathering	Fort Union Gas Gathering, L.L.C.
GAAP	Accounting principles generally accepted in the United States of America
Guardian Pipeline	Guardian Pipeline, L.L.C.
Intermediate Partnership	ONEOK Partners Intermediate Limited Partnership, a wholly owned subsidiary of ONEOK Partners, L.P.
IRS	Internal Revenue Service
KCC	Kansas Corporation Commission
KDHE	Kansas Department of Health and Environment
LIBOR	London Interbank Offered Rate
MBbl	Thousand barrels
MBbl/d	Thousand barrels per day
MDth/d	Thousand dekatherms per day
Midwestern Gas Transmission	Midwestern Gas Transmission Company
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)
Northern Border Pipeline	Northern Border Pipeline Company
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
OBPI	ONEOK Bushton Processing, L.L.C., formerly ONEOK Bushton Processing, Inc.
OCC	Oklahoma Corporation Commission

OKTex Pipeline	OkTex Pipeline Company, L.L.C.
ONEOK	ONEOK, Inc.
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
Overland Pass Pipeline Company	Overland Pass Pipeline Company LLC
Partnership Agreement	Third Amended and Restated Agreement of Limited Partnership of ONEOK Partners, L.P., as amended
Partnership Credit Agreement	The Partnership's $1.2 billion Revolving Credit Agreement dated August 1, 2011, as amended
PHMSA	United States Department of Transportation Pipeline and Hazardous Materials Safety Administration
POP	Percent of Proceeds
Quarterly Report(s)	Quarterly Report(s) on Form 10-Q
RRC	Railroad Commission of Texas
S&P	Standard & Poor's Rating Services
SEC	Securities and Exchange Commission
Securities Act	Securities Act of 1933, as amended
TransCanada	TransCanada Corporation
Viking Gas Transmission	Viking Gas Transmission Company
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 Operation, 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 and Rocky Mountain regions with key market centers. We apply our core capabilities of gathering, processing, fractionating, transporting, storing, marketing and distributing 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

In 2012, producers continued to drill aggressively in a number of crude oil and NGL-rich natural gas resource areas in the Mid-Continent and Rocky Mountain regions creating the need for additional natural gas gathering and processing and natural gas liquids infrastructure to bring this additional production to market. Natural gas prices were lower in 2012, caused by increased supply driven by the drilling activities and decreased demand primarily driven by a warmer than normal winter. These two factors also resulted in less natural gas price volatility and narrower natural gas location and seasonal price differentials in the markets we serve. NGL prices, particularly ethane and propane, also decreased in 2012 due primarily to increased NGL production from the development of NGL-rich areas. Propane prices also were affected by a warmer than normal winter.

We generally have seen strong ethane demand from the petrochemical sector in the Gulf Coast region due to the price advantage ethane has over other feedstocks. In 2011, natural gas liquids pipeline capacity between the Conway, Kansas, and Mont Belvieu, Texas, market centers was constrained and contributed to wider location price differentials between those markets. The natural gas supply growth during 2011 resulted in increased NGL supply in the Mid-Continent region, and when coupled with increased demand in the Gulf Coast region, resulted in lower NGL prices in the Mid-Continent market center at Conway, Kansas, relative to prices in the Gulf Coast market center at Mont Belvieu, Texas. During the second half of 2012, due to continued strong production 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, NGL price differentials narrowed between the Mid-Continent and the Gulf Coast market centers. We expect the narrow NGL price differentials between these market centers to continue as new fractionators and pipelines, including our growth projects discussed below, continue to alleviate constraints affecting NGL prices and location price differentials between the two market centers. Over time, these growing fee-based NGL volumes are expected to fill much of our capacity used historically to capture NGL price differentials between the two market centers.

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 ethane and propane available to be gathered from natural gas processing plants. When economic conditions warrant, natural gas processors may elect not to recover the ethane component of the natural gas stream, also known as ethane rejection, and instead leave 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 periods of ethane rejection in the Mid-Continent and Rocky Mountain regions during 2012. Ethane rejection did not have a material impact on our financial results. We expect lower natural gas liquids volumes in our Natural Gas Liquids segment as a result of widespread and prolonged ethane rejection in 2013 that is expected to have a significant impact on our financial results. We do not expect prolonged ethane rejection to continue into 2014.

Despite lower commodity prices, North American natural gas production continues to increase at a faster rate than demand, primarily as a result of increased production from nonconventional resource areas such as shale areas. Producers receive currently higher market prices on a heating-value basis for crude oil and NGLs compared with natural gas. As a result, many producers focused their drilling activity in shale areas that produce crude oil and NGL-rich natural gas rather than areas with dry natural gas production. We expect continued demand for midstream infrastructure development driven by producers who need to connect emerging production with end-use markets where current infrastructure is insufficient or nonexistent.

Additional natural gas liquids fractionation and pipeline capacity is needed to accommodate the growing NGL supply and demand, as well as new infrastructure to gather, process and transport growing natural gas production from both new and existing resource areas. In response to this increased production and demand for NGL products, we are investing approximately $4.7 billion to $5.3 billion in new capital projects to meet the needs of crude oil, NGL and natural gas producers in the Bakken Shale and Three Forks formations in the Williston Basin, the Cana-Woodford Shale, Woodford Shale, Mississippian Lime and Granite Wash areas, and for additional natural gas liquids infrastructure in the Mid-Continent and Gulf Coast areas that will enhance the distribution of NGL products to meet the increasing petrochemical industry and NGL export demand. When completed, we expect these projects to provide additional earnings and cash flows.

During 2012, we paid cash distributions of $2.59 per unit, an increase of approximately 11 percent over the $2.325 per unit paid during 2011. In January 2013, our general partner declared a cash distribution of $0.71 per unit ($2.84 per unit on an annualized basis), an increase of approximately 16 percent over the $0.61 declared in January 2012.

In 2012, we issued 16 million common units and $1.3 billion of senior notes, generating net proceeds of approximately $2.2 billion. We utilized proceeds from these equity and debt issuances, cash from operations and our commercial paper program to meet our short-term liquidity needs, repay maturing debt and to fund our capital 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.

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 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:

- Operate in a safe, reliable and environmentally responsible manner - environmental, safety and health issues continue to be a primary focus for us; 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;
- Generate consistent growth and sustainable earnings - we continue to increase NGL volumes gathered and fractionated in our Natural Gas Liquids segment and natural gas volumes processed in our Natural Gas Gathering and Processing segment, which generate earnings from predominately POP and fee-based contracts, as producers continue to develop NGL-rich resource areas that we serve in the Mid-Continent and Rocky Mountain areas. We are investing approximately $4.7 billion to $5.3 billion in new capital projects to meet the needs of crude oil, NGL and natural gas producers in the Williston Basin, the Cana-Woodford Shale, Woodford Shale, Mississippian Lime and Granite Wash areas, and for additional natural gas liquids infrastructure in the Mid-Continent and Gulf Coast areas that will enhance the distribution of NGL products to meet the increasing petrochemical industry and NGL export demand, which, when completed, are anticipated to provide additional earnings and cash flows;
- Execute strategic acquisitions that provide long-term value - we remain disciplined in our approach and continue to evaluate assets that come to market. We did not consummate any acquisitions in 2012;
- Manage our balance sheet and maintain strong credit ratings - our balance sheet remains strong, ending 2012 with full availability of the borrowing capacity under our commercial paper program and revolving credit agreement, $537 million of cash and a capital structure of 52-percent debt and 48-percent equity. We will seek to maintain our investment-grade credit ratings; and
- Attract, select, develop and retain employees to support strategy execution - we continue to execute on our recruiting strategy that targets colleges, universities and vocational-technical schools in our operating areas. We also continue to focus on employee development efforts with our current employees.

NARRATIVE DESCRIPTION OF BUSINESS

We report operations in the following business segments:

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

Natural Gas Gathering and Processing

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. We gather and process natural gas in the Mid-Continent region, which includes the NGL-rich Cana-Woodford Shale and Granite Wash formations, 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. The natural gas we gather in 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.

In the Mid-Continent region and the Williston Basin, unprocessed natural gas is compressed and transported through pipelines 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. Our natural gas and NGLs are sold to our affiliates and a diverse customer base.

Our natural gas processing operations primarily utilize field natural gas processing plants to extract NGLs and remove water vapor and other contaminants from the unprocessed natural gas stream. Field natural gas processing plants process natural gas gathered from multiple producing wells.

We generally gather and process natural gas under the following types of contracts.

- POP - Under a POP contract, we retain a percentage of the NGLs and/or a percentage of the residue gas as payment for gathering, treating, compressing and processing the producer's natural gas. The producer may take its share of the NGLs and residue gas in-kind or receive its share of proceeds from our sale of the commodities. POP contracts expose us to both natural gas and NGL commodity price risks but economically align us with the producer because we both benefit from higher commodity prices, reduced costs and improved efficiencies. This type of contract represented approximately 41 percent and 37 percent of contracted volumes for 2012 and 2011, respectively. There are a variety of factors that directly affect our POP margins, including:
    - the percentages of products retained by us that represent NGL, condensate and residue natural gas sales volumes that we receive as payment for the services we provide;
    - transportation and fractionation costs incurred on the NGLs we retain; and
    - the natural gas, crude oil and NGL prices received for our retained products.
- Fee - Under a fee-based contract, we are paid a fee for the services provided that is based on Btus gathered, treated, compressed and/or processed. The wellhead volume and fees received for the services provided are the main components of our margin for this type of contract. The producer typically takes its NGLs and residue natural gas in-kind. Our POP and keep-whole contracts also typically include fee provisions, which are a portion of the fees reported in this category. Our fee-based contracts and contract provisions primarily expose us to volumetric risk with minimal commodity price risk and represented approximately 57 percent and 60 percent of contracted volumes for 2012 and 2011, respectively.
- Keep-Whole - Under a keep-whole contract, we extract NGLs from the unprocessed natural gas and return to the producer volumes of residue gas containing the same amount of Btus as the unprocessed natural gas that was delivered to us. We retain the NGLs as our fee for processing. Accordingly, we must purchase and return to the producer sufficient volumes of residue gas to replace the Btus that were removed as NGLs through the gathering and processing operation, commonly referred to as "shrink." This type of contract represented approximately 2 percent and 3 percent of contracted volumes for 2012 and 2011, respectively. Approximately 78 percent and 75 percent of our volume under keep-whole contracts for 2012 and 2011, respectively, contain terms that effectively convert these contracts into fee contracts when the gross processing spread is negative.

Our revenues from this segment are derived primarily from POP and fee contracts. We expect that our capital projects will provide additional revenues from POP and fee contracts when completed. We use derivative instruments to mitigate our sensitivity to fluctuations in the natural gas, crude oil and NGL prices received for our share of volumes.

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 natural gas into the interstate pipeline grid;
- 35-percent ownership interest in Lost Creek Gathering Company, L.L.C., 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., L.L.C., a natural gas processing complex near Venice, Louisiana.

See Note K 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. Crude oil prices and advances in horizontal drilling and completion technology have had a positive impact on drilling activity in the shale areas and other resource areas, providing an offset to the less favorable supply projections in some of the conventional resource areas.

In the Rocky Mountain region, Williston Basin volumes continue to grow as well connections from drilling completions increase, driven primarily by producer development of Bakken Shale crude oil wells, which also produce associated natural gas containing significant quantities of NGLs. However, we have seen declines in natural gas volumes gathered in the Powder River Basin, which produces dry gas.

In the Mid-Continent region, we have a significant amount of natural gas gathering and processing assets in western Oklahoma and southwest Kansas. We expect increased drilling activity in the Cana-Woodford Shale and Granite Wash areas of western Oklahoma and the Mississippian Lime formation of Oklahoma and Kansas to more than offset the volumetric declines in most conventional wells that supply our natural gas gathering and processing facilities.

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. As producers continue to develop NGL-rich shale and other resource areas, we expect demand for our gathering and processing services to increase.

Commodity Prices - Crude oil, natural gas and NGL prices are volatile due to changes in market conditions such as the availability of supply, storage injection and withdrawal rates, available storage capacity and demand for our products by the petrochemical industry and other consumers. We are exposed to commodity price risk and the cost of natural gas transportation at 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 minimize the 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 not to recover the ethane component of the natural gas stream, also known as ethane rejection, and instead leave 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, to some extent, the amount of ethane recovered if the price differential is unfavorable.

Seasonality - Certain of this segment’s products 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 gas-fired electric generation needed to meet the electricity-generation demand required to cool residential and commercial properties. Demand for iso-butane 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 as 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;
- 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;
- pressures maintained on our gathering systems;
- efficiency and reliability of our operations; and
- delivery capabilities for natural gas and natural gas liquids that exist in each system and plant location.

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. We are responding to these industry conditions by making capital investments to construct and expand our assets, improve natural gas processing efficiency and reduce operating costs, evaluating consolidation opportunities to maximize earnings, and renegotiating low-margin contracts, with the principal goals of improving margins and reducing risk.

Government Regulation - The FERC has traditionally 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 “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 transports natural gas from an interconnection with TransCanada’s pipeline near Emerson, Manitoba, to serve local natural gas distribution companies in Minnesota, North Dakota and Wisconsin, and terminates at a connection with 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 have access to the major natural gas producing areas, including the Cana-Woodford Shale, Granite Wash, Delaware, Cline and Mississippian Lime areas, and transport natural gas throughout the state. We also have access to the major natural gas producing area 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 area, and the Permian Basin; and transport natural gas throughout the western portion of the state, 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, Kansas and Texas, which are connected to our intrastate natural gas pipeline assets.

Our Natural Gas Pipelines segment's revenues are derived typically from fee-based services provided to our customers. Our 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, 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 K 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 shale gas 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 or may require incremental services to transport their production to market. Our intrastate pipelines and storage assets depend on 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, which includes the Cana-Woodford Shale, Granite Wash and Mississippian Lime areas, Hugoton Basin and Central Kansas Uplift Basin. The supply of natural gas for Viking Gas Transmission and Northern Border Pipeline originates in Canada. Significant factors that can impact the supply of Canadian natural gas transported by our pipelines are the Canadian natural gas available for export, Canadian storage capacity and demand for Canadian natural gas in Canada and United States consumer markets. Guardian Pipeline and Midwestern Gas Transmission access supply from the major producing regions of the Mid-Continent, Rocky Mountains, Canada and Gulf Coast.

Demand - Demand for natural gas pipeline transportation service and natural gas storage is related directly to demand for natural gas in the markets that our natural gas pipelines and storage facilities serve, and is affected by weather, the economy and natural gas and NGL 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 can also be impacted as coal-fired electric generators consider natural gas as an alternative fuel. 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–may increase the demand for natural gas as well as related transportation and storage services.   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, the level of NGLs processed from natural gas and natural gas storage injection and withdrawal activity.

Commodity Prices - The increase in natural gas supply from shale gas development has caused natural gas prices to decline and natural gas location and seasonal price differentials to narrow across most of the regions where we operate. We are exposed to market risk when existing 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 are also impacted by changes in the price of natural gas.

Seasonality - Demand for natural gas is seasonal. Weather conditions throughout North America can significantly impact regional natural gas supply and demand. High temperatures can increase demand for gas-fired electric generation needed to meet the electricity demand required to cool residential and commercial properties. Cold temperatures can lead to greater demand for our transportation services due to increased demand for natural gas to heat residential and commercial properties. Low precipitation levels can 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 can impact 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. A small portion of our storage capacity is retained for operational purposes.

Competition - Our natural gas pipelines and storage facilities compete directly with other intrastate and interstate pipeline companies and other storage facilities in 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 natural gas for electric generation that has traditionally been fueled by coal. The cost of coal and the associated rail costs continue to compete with natural gas for this market, but the clean-burning aspects of natural gas and abundance of supply make it an economically competitive and environmentally advantaged alternative. We believe that we compete effectively with our pipelines and storage assets 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.

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

Natural Gas Liquids

Overview - Our natural gas liquids assets provide nondiscretionary services to producers that consist of facilities that gather, fractionate and treat NGLs and store NGL products primarily in Oklahoma, Kansas and Texas. We own or have an ownership interest in FERC-regulated natural gas liquids gathering and distribution pipelines in Oklahoma, Kansas, Texas, Wyoming, Colorado, North Dakota and Montana, 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 raw NGLs from unprocessed natural gas, are connected to our natural gas liquids gathering systems. We own and operate truck and rail-loading and unloading facilities that interconnect with our fractionation and pipeline assets. Through recent expansions to our rail facilities in Kansas, we began receiving raw NGLs transported by rail from the Williston Basin to our Kansas fractionation facilities in early 2012. We will continue to receive these Williston Basin NGLs through our rail-loading facilities until construction is completed on our Bakken NGL Pipeline, which is expected to be in service in the first quarter 2013. At that time, we plan to use these rail facilities for our NGL marketing activities.

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 from our Natural Gas Liquids segment are derived primarily from nondiscretionary fee-based services provided to our customers and physical optimization of our assets. Our fee-based services have increased primarily due to our previously completed capital projects, including our Cana-Woodford Shale and Granite Wash projects and expansion of our fractionation capacity. Our sources of revenue are categorized as follows:

- Our exchange services' activities utilize our assets to gather, fractionate and 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 and seasonal price differentials. We transport NGL products between the Mid-Continent and Gulf Coast in order 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 our 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 store NGLs at our Mid-Continent and Gulf Coast facilities for a fee.

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

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

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

Market Conditions and Seasonality - <u>Supply</u> - 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. We are seeing rapid NGL supply growth within our operating footprint as producers continue to aggressively drill in a number of NGL-rich resource areas in the Mid-Continent and Rocky Mountain regions. We expect the overall supply of NGLs to continue to increase, as well as demand for our fee-based services, as a result of the development of these resource areas. Many new natural gas processing plants are being constructed in Oklahoma and the Texas Panhandle to process NGL-rich natural gas being produced in the Cana-Woodford Shale, the Granite Wash, the Woodford Shale and the Mississippian Lime areas. The unfractionated NGLs that we transport are gathered primarily from natural gas processing plants in Oklahoma, Kansas, Texas 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 is also affected by operational or market-driven changes that impact 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, may influence the volume of NGLs available to be gathered from the natural gas processing plants. During 2012, the value of ethane was periodically below that of natural gas, which negatively impacted the economic incentive for ethane recovery and caused some natural gas processing plants that deliver NGLs to our natural gas liquids gathering pipelines to reduce ethane production. There are a variety of factors that affect whether a processing plant will reduce or reject ethane production; however, we expect periods of low ethane prices relative to natural gas, causing intermittent periods of lower ethane production during 2013. During 2012, ethane rejection did not have a material impact on our financial results. We expect lower natural gas liquids volumes in our Natural Gas Liquids segment as a result of widespread and prolonged ethane rejection in 2013 that is expected to have a significant impact on our financial results. We do not expect prolonged ethane rejection to continue into 2014.

Natural gas and/or natural gas liquids pipeline capacity constraints may also impact the output of natural gas processing plants in total or for specific NGL products in the future. During 2012, we experienced limited reductions of supply related to changes in plant output as a result of pipeline capacity constraints.

Demand - Demand for NGLs and the ability of natural gas processors to successfully and economically sustain their operations impacts 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 fiber. 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 as a petrochemical feedstock in the United States. As these projects are completed over the next five years, we expect ethane demand to increase. The demand is expected to increase significantly in three to five years when the new petrochemical plants are completed. In addition, international demand for propane is expected to impact the NGL market in the future. We expect this increase in demand for NGLs will provide opportunities for our exchange services activities to add incremental fee-based earnings.

Commodity Prices - In recent years, crude oil and NGL prices have been volatile due to market conditions. The abundance of NGLs produced from the development of shale and other resource areas has made NGL feedstocks to the petrochemical industry more competitive. We are exposed to market risk associated with adverse 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 impact our NGL purchases, sales, transportation, exchange and storage revenue. When natural gas prices are higher relative to NGL prices, NGL production may decline due to ethane rejection, which could negatively impact 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. During the second half of 2012, due to 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, NGL price differentials narrowed between the Mid-Continent market center at Conway, Kansas, and the Gulf Coast market center at Mont Belvieu, Texas. NGL storage revenue may be impacted by price volatility and forward pricing of NGL physical contracts versus the price of NGLs on the spot market.

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 grain 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 are in place.

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, 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;
- pressures maintained on our gathering systems;
- efficiency and reliability of our operations; and
- receipt and delivery capabilities that exist in each pipeline system, plant, fractionator and storage location.

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 have also recently announced plans for, and in some cases are already constructing or have completed, new natural gas liquids pipeline and fractionation projects to address the growing NGL supply and petrochemical demand. When completed, our growth projects and those of our competitors are expected to impact NGL prices and narrow location price differentials between the Mid-Continent and Gulf Coast market centers. 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 Oklahoma, Kansas and Texas, our intrastate natural gas liquids pipelines that provide common carrier service are subject to the jurisdiction of the OCC, KCC and RRC, respectively.

PHMSA has asserted jurisdiction over certain portions of our fractionation facilities in Bushton, Kansas, that we believe are not 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 "Environmental and Safety Matters" section.

SEGMENT FINANCIAL INFORMATION

Operating Income, Customers and Total Assets - See Note N 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.

FINANCIAL MARKETS LEGISLATION

The Dodd-Frank Act represents a far-reaching overhaul of the framework for regulation of United States financial markets. Various regulatory agencies, including the SEC and the CFTC, have proposed regulations for implementation of many of the provisions of the Dodd-Frank Act. The CFTC has issued final regulations for many provisions of the Dodd-Frank Act that have varying effective dates for compliance, but others remain outstanding. Based on our assessment of the regulations issued to date and those proposed, we expect to be able to continue to participate in financial markets for hedging certain risks inherent in our business, including commodity and interest-rate risks; however, the capital requirements and costs of hedging may increase as a result of the regulations. We also may incur additional costs associated with our compliance with the new regulations and anticipated additional record keeping, reporting and disclosure obligations; however, we do not believe the costs will be material. These requirements could affect adversely market liquidity and pricing of derivative contracts, making it more difficult to execute our risk-management strategies in the future. Also, the anticipated increased costs of compliance by dealers and counterparties likely will be passed on to customers, which could decrease the benefits of hedging to us and could reduce our profitability and liquidity.

ENVIRONMENTAL AND SAFETY MATTERS

Environmental Matters - We are subject to multiple historical, wildlife preservation and environmental laws and regulations, which 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 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. Revised or additional statutes or regulations that result in increased compliance costs or additional operating restrictions could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Pipeline Safety - We are subject to PHMSA regulations, including 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 new law increased the 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 of 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 emissions are under way. We monitor all relevant federal and state legislation to assess the potential impact on our operations. In 2009, the EPA released its Mandatory Greenhouse Gas Reporting Rule, which requires the annual reporting of greenhouse gas emissions from affected facilities and the carbon dioxide equivalents of the NGLs produced by our fractionation facilities as if all of these products were combusted, even if they are used otherwise. Also, the EPA released a subpart to the Mandatory Greenhouse Gas Reporting Rule that requires the annual reporting of vented and fugitive emissions of methane from certain facilities beginning with the reporting of 2011 fugitive emission in 2012. Our 2011 total reported emissions were approximately 50.1 million metric tons of carbon dioxide equivalents. The additional cost to gather and report this emission data did not have, and we do not expect it to have, any material impact going forward on our results of operations, financial position or cash flows. In addition, Congress has considered, and may consider in the future, legislation to reduce greenhouse gas emissions, including carbon dioxide and methane. Likewise, the EPA may institute additional regulatory rulemaking associated with greenhouse gas emissions. At this time, no rule or legislation has been enacted that assesses any costs, fees or expenses on any of these emissions.

In May 2010, the EPA finalized the "Tailoring Rule" that regulates greenhouse gas emissions at new or modified facilities that meet certain criteria. Affected facilities are required to review best available control technology, conduct air-quality analysis, impact analysis and public reviews with respect to such emissions. The rule was phased in beginning January 2011 and at current emission threshold levels has not had a material impact on our existing facilities. The EPA has stated it will consider lowering the threshold levels over the next five years, which could increase the impact on our existing facilities; however, potential costs, fees or expenses associated with the potential adjustments are unknown.

In 2010, the EPA issued a rule on air-quality standards titled, "National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines," also known as RICE NESHAP, which initially included a compliance date in 2013. Subsequent industry appeals and settlements with the EPA have extended timelines associated with the final RICE NESHAP rule. While the rule could require capital expenditures for the purchase and installation of new emissions-control equipment, we do not expect these expenditures will have a material impact on our results of operations, financial position or cash flows.

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 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. Further, pursuant to various industry comments, administrative petitions for reconsideration and/or judicial appeals of portions of the NSPS final rule, the EPA has indicated it may provide certain responses, amendments and/or policy guidance to amend or clarify portions of the final rule in 2013. We anticipate that if the EPA issues additional responses, amendments and/or policy guidance on the final rule, it will reduce the anticipated capital, operations and maintenance costs resulting from the regulation. Generally, the NSPS final 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) that 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. In 2011, we received notice from the EPA of potential liability at the U.S. Oil Recovery Superfund Site location in Harris County, Texas, where we were named a potentially responsible party as a result of waste disposal at the now-abandoned site. We do not expect our responsibilities under CERCLA, for this facility or any other, 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 will 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 taking steps to minimize the impact of our operations on the environment. These strategies include: (i) developing and maintaining an accurate greenhouse gas 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 voluntarily reduce methane emissions. We continue to focus on maintaining low rates of lost-and-unaccounted-for natural 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, 2013, we utilized some or all of the services of 4,859 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 are also 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 discuss 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 carefully consider 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 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 affect 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 cost and increasingly restrictive covenants.

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 for the sale of NGL products in our Natural Gas Liquids segment. 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 NGL fractionation capacity;
- the level of consumer product demand;
- 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 price of natural gas, crude oil, NGL and liquefied natural gas imports;
- 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. 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 and natural gas 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 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.

We do not hedge fully against commodity price changes. 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 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 differentials between NGL and natural gas prices associated with our keep-whole contracts;
- the price differential 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 physical forward transactions and commodity derivative instruments such as futures contracts, swaps and options. However, we do not hedge fully against commodity price changes, and we therefore retain some exposure to market risk. Accordingly, any adverse changes to commodity prices could result in decreased revenue and increased costs.

Our use of financial instruments and physical forward transactions to hedge market risk 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.

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 ONEOK Partners GP senior management and the Audit Committee of ONEOK Partners GP's Board of Directors to assist us in managing risks. 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.

The adoption and implementation of new statutory and regulatory requirements for derivative transactions could have an adverse impact on our ability to hedge risks associated with our business and increase the working capital requirements to conduct these activities.

In July 2010, the Dodd-Frank Act was enacted, which provides for new statutory and regulatory requirements for certain swap transactions. Certain financial transactions will be required to be cleared on exchanges, and cash collateral will be required for these transactions. However, the Dodd-Frank Act provides for a potential exemption from these clearing and cash collateral requirements for commercial end-users and includes a number of defined terms that will be used in determining how this exemption applies to particular derivative transactions and to the parties to those transactions. Additionally, the Dodd-Frank Act calls for various regulatory agencies, including the SEC and the CFTC, to establish regulations for implementation of many of the provisions of the act.

The SEC and CFTC have proposed regulations for implementation of many provisions of the Dodd-Frank Act. The CFTC has issued final regulations for many provisions of the Dodd-Frank Act that have varying effective dates for compliance, but others remain outstanding. Based on our assessment of the regulations issued to date and those proposed, we expect to be able to continue to participate in financial markets for hedging certain risks inherent in our business, including commodity and interest-rate risks; however, the capital requirements and costs of hedging may increase as a result of the regulations. We may also incur additional costs associated with our compliance with the new regulations and anticipated additional record keeping, reporting and disclosure obligations. These requirements could affect adversely market liquidity and pricing of derivative contracts, making it more difficult to execute our risk-management strategies in the future. Also, the anticipated increased costs of compliance by dealers and counterparties likely will be passed on to customers, which could decrease the benefits of hedging to us and could reduce our profitability and liquidity.

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, impact 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 materially and adversely affect 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 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 materially and adversely affect 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 aimed 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 twenty 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.

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;
- 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; and
- an EPA-issued rule on air-quality standards, known as RICE NESHAP.

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 M 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 greenhouse gas emissions.

Greenhouse gas 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 greenhouse gases, 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 greenhouse gases.

We believe it is likely that future governmental legislation and/or regulation may require us either to limit greenhouse gas 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 greenhouse gases 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 greenhouse gas 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 greenhouse gas 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 greenhouse gas 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 greenhouse gas 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 may not be able to pass on the higher costs to our customers or recover all costs related to complying with greenhouse gas emission regulatory requirements, which could cause material adverse effects on our business, financial condition, results of operations and cash flows.

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

There is a growing belief that emissions of greenhouse gases 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 greenhouse gases as a financial risk, this could negatively affect 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 greenhouse gas emitters, based on links drawn between greenhouse gas emissions and climate change.

Continued development of new supply sources could impact demand.

The discovery of unconventional 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, New York, 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, 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 increasingly relying on natural gas supplies from unconventional sources, such as shale, tight sands and coal-bed methane gas. 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 gathered, treated, processed and transported on our or our joint ventures' natural gas pipelines, several of which gather unprocessed natural gas from areas in which 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 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 results of operations and cash flows available for distributions.

Mergers among 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 and results of operations.

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.

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.

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 earnings and cash flows.

A failure in our operational systems or cyber security attacks on any of our facilities, or those of third parties, may affect adversely our financial results.

Our businesses are dependent upon our operational systems to process a large amount of data and complex transactions. If any of our financial, operational or other data processing systems fail or have other significant shortcomings, our financial results could be affected adversely. 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. Any future cyber security attacks that affect our facilities, our customers and any financial data could have a material adverse effect on our businesses. In addition, cyber attacks on our customer and employee data may result in a financial loss and may impact negatively our reputation. Third-party systems on which we rely could also suffer operational system failure. Any of these occurrences could disrupt one or more of our businesses, result in potential liability or reputational damage or otherwise have an adverse affect on our financial results.

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 which 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 deterioration of their financial condition as a result of changing market conditions 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 results of operations.

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 natural gas production continues to decline in the Powder River Basin, we could be unable to recover the carrying value of our assets and equity investments in this area. 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, 19,800,000 common units and the entire 2-percent general partner interest in us, which together constituted a 43.4-percent ownership interest in us as of December 31, 2012. 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 March 2012 public offering of common units, ONEOK and its subsidiaries own a 43.4-percent aggregate equity interest in us. 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. Six of the nine members of the Board of Directors of our general partner are either members of ONEOK's Board of Directors or executive management of ONEOK. Four independent members and one management member of the Board of Directors of our general partner are also 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 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, 2012, we had total indebtedness of approximately $4.8 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 legal 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.

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 non-recourse to the Partnership are not counted for purposes of determining whether a distribution is permitted.

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

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

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

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

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

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

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

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

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

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

Our operating cash flow is derived partially from cash distributions we receive from our unconsolidated affiliates, as discussed in Note K 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 would be effectively 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. 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.

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 have considered 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 impact 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 impact 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 impact 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 will 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 will 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 the 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 will 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 a technical termination 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 10,900 miles and 6,200 miles of natural gas gathering pipelines in the Mid-Continent and Rocky Mountain regions, respectively;
- nine natural gas processing plants, with approximately 645 MMcf/d of processing capacity, in the Mid-Continent region, and six natural gas processing plants, with approximately 315 MMcf/d of processing capacity, in the Rocky Mountain region; and
- approximately 24 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 assets:

- approximately 270 miles of natural gas gathering pipelines in the Rocky Mountain region;
- three natural gas processing plants, with approximately 300 MMcf/d of combined processing capacity, in the Rocky Mountain region; and
- one natural gas processing plant, with approximately 200 MMcf/d of processing capacity, in the Mid-Continent region.

Utilization - The utilization rates for our natural gas processing plants were approximately 69 percent and 71 percent for 2012 and 2011, respectively. We calculate utilization rates using a weighted-average approach, adjusting for the dates that assets were placed in service.

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 3.1 Bcf/d of peak transportation capacity;
- approximately 5,100 miles of state-regulated intrastate transmission pipelines with peak transportation capacity of approximately 3.0 Bcf/d; and
- approximately 51.7 Bcf of total active working natural gas storage capacity.

Our storage includes five underground natural gas storage facilities in Oklahoma, three underground natural gas storage facilities in Kansas and three underground natural gas storage facilities in Texas. One of our natural gas storage facilities outside of Hutchinson, Kansas, has been idle since 2001. In compliance with a KDHE order, we began injecting brine into that facility in the first quarter 2007 and completed injection at the end of 2012 in order to ensure the long-term integrity of the idled facility. Monitoring of the facility and review of the data for the geo-engineering studies are ongoing, in compliance with a KDHE order, while we evaluate the alternatives for the facility. Following the testing of the gathered data, we expect that the facility will be returned to storage service, although most likely for a product other than natural gas. The return to service will require additional actions and KDHE approval. It is possible, however, that testing could reveal that it is not safe to return the facility to service or that the KDHE will not grant the required permits to resume service.

Utilization - Our natural gas pipelines were approximately 89 percent subscribed for each year, 2012 and 2011, and our natural gas storage facilities were fully subscribed both years.

Natural Gas Liquids

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

- approximately 2,700 miles of natural gas liquids gathering pipelines with peak gathering capacity of approximately 772 MBbl/d;
- approximately 170 miles of natural gas liquids distribution pipelines with peak transportation capacity of approximately 66 MBbl/d;
- approximately 840 miles of FERC-regulated natural gas liquids gathering pipelines with peak capacity of approximately 200 MBbl/d;

- approximately 3,500 miles of FERC-regulated natural gas liquids and refined petroleum products distribution pipelines with peak capacity of 708 MBbl/d;
- two natural gas liquids fractionators with combined operating capacity of approximately 260 MBbl/d, which are located in Oklahoma and Kansas; one natural gas liquids fractionator with operating capacity of 210 MBbl/d located at the Bushton facility in Kansas;
- 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; and
- 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.

In addition, we lease approximately 2.5 MMBbl of combined NGL storage capacity at facilities in Kansas and Texas.

Utilization - The utilization rates for our various assets, including leased assets, for 2012 and 2011, respectively, were as follows:

- our non-FERC-regulated natural gas liquids pipelines were approximately 68 percent and 71 percent;
- our FERC-regulated natural gas liquids gathering pipelines were approximately 99 percent and 97 percent;
- our FERC-regulated natural gas liquids distribution pipelines were approximately 65 percent in each year;
- our average contracted natural gas liquids storage volumes were approximately 60 percent and 63 percent of storage capacity; and
- our natural gas liquids fractionators were approximately 89 percent in both years.

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 are constructing or plan to construct the following assets:

- approximately 600 miles of FERC-regulated natural gas liquids gathering pipelines from the Williston Basin to the Overland Pass Pipeline with peak capacity of 135 MBbl/d;
- approximately 540 miles of FERC-regulated natural gas liquids distribution pipelines from Medford, Oklahoma, to Mont Belvieu, Texas, with peak capacity of 193 MBbl/d;
- two natural gas liquids fractionators with combined operating capacity of approximately 150 MBbl/d that will be located in Texas; and
- one ethane/propane splitter with the capability of producing 32 MBbl/d of purity ethane and 8 MBbl/d of propane that will be located in Texas.

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.

ITEM 3. LEGAL PROCEEDINGS

We are a party to various litigation matters and claims that arise 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 liquidity.

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, 2012		Year Ended December 31, 2011	
	High	**Low**	**High**	**Low**
First Quarter	**$ 61.23**	**$ 53.65**	$ 41.83	$ 39.42
Second Quarter	**$ 57.25**	**$ 51.16**	$ 43.18	$ 40.00
Third Quarter	**$ 59.50**	**$ 54.96**	$ 46.62	$ 37.74
Fourth Quarter	**$ 60.95**	**$ 52.89**	$ 57.94	$ 45.05

At February 19, 2013, there were 617 holders of record of our 146,827,354 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 43.4-percent ownership interest in us.

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, 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
September 30, 2011	$ 0.595	October 26, 2011	November 14, 2011
June 30, 2011	$ 0.585	July 21, 2011	August 12, 2011
March 31, 2011	$ 0.575	April 20, 2011	May 13, 2011
December 31, 2010	$ 0.570	January 20, 2011	February 14, 2011

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.

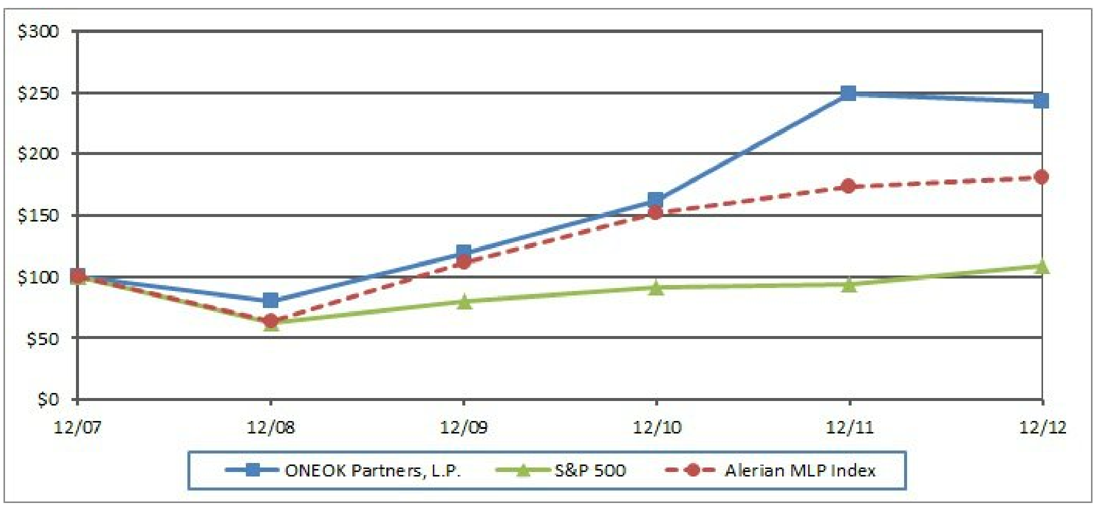
If our common unitholders vote at any time to remove ONEOK or its affiliates as our general partner, quarterly distributions payable on the Class B limited partner units would increase to 123.5 percent of the distributions payable with respect to the common units, and distributions payable upon liquidation 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 $760.9 million, $609.4 million and $563.2 million for 2012, 2011 and 2010, respectively, which included an incentive distribution to our general partner of $186.1 million, $123.4 million and $103.5 million for 2012, 2011 and 2010, 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, 2007, and ending on December 31, 2012. 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, 2007, and at the End of Every Year Through December 31, 2012, Among ONEOK Partners, L.P., the S&P 500 Index and the Alerian MLP Index



	Cumulative Total Return				
	Years Ended December 31,				
	2008	2009	2010	2011	2012
ONEOK Partners, L.P.	$ 79.98	$ 119.04	$ 162.25	$ 248.44	**$ 243.08**
S&P 500 Index	$ 63.01	$ 79.69	$ 91.71	$ 93.62	**$ 108.59**
Alerian MLP Index (a)	$ 63.24	$ 111.55	$ 151.61	$ 172.72	**$ 181.03**

(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,				
	2012	**2011**	**2010**	**2009**	**2008**
	(In millions of dollars, except per unit data)				
Revenues	**$ 10,182.2**	$ 11,322.6	$ 8,675.9	$ 6,474.5	$ 7,720.2
Net income	**$ 888.4**	$ 830.9	$ 473.3	$ 434.7	$ 626.1
Net income attributable to ONEOK Partners, L.P.	**$ 888.0**	$ 830.3	$ 472.7	$ 434.4	$ 625.6
Limited partners' net income per unit	**$ 3.04**	$ 3.35	$ 1.75	$ 1.80	$ 3.01
Distributions paid per common unit (a)	**$ 2.590**	$ 2.325	$ 2.230	$ 2.165	$ 2.105
Total assets	**$ 10,959.2**	$ 8,946.7	$ 7,920.1	$ 7,953.3	$ 7,254.3
Long-term debt, including current maturities	**$ 4,811.3**	$ 3,876.6	$ 2,818.5	$ 3,084.0	$ 2,601.4

(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.

Growth Projects - Crude-oil and natural gas producers continue to drill aggressively in crude-oil and NGL-rich areas, and related development activities continue to progress in many regions where we have operations. We expect continued development of the crude-oil and natural gas reserves in the Bakken Shale and Three Forks formations in the Williston Basin and in the Cana-Woodford Shale, Woodford Shale, Granite Wash and Mississippian Lime 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 are investing approximately $4.7 billion to $5.3 billion in new capital projects between 2011 and 2015 to meet the needs of natural gas producers and processors in the Bakken Shale, the Cana-Woodford Shale, Woodford Shale and the Granite Wash and Mississippian Lime areas. In addition, we are investing in NGL infrastructure projects in the Rocky Mountain, Mid-Continent and Gulf Coast regions. These assets will enhance our distribution of NGL products to meet the increasing petrochemical industry and NGL export demand. The execution of these capital investments aligns with our focus to grow fee-based earnings. Our acreage dedications and supply commitments from natural gas producers and processors in regions associated with our growth projects are expected to provide incremental and long-term fee-based earnings and cash flows.

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

Bakken Crude Express Pipeline - In April 2012, we announced plans to build a 1,300-mile crude-oil pipeline, the Bakken Crude Express Pipeline, with the capacity to transport 200 MBbl/d. We held an open season process that provided potential shippers with the opportunity to execute long-term transportation contracts with us in exchange for priority transportation service. In November 2012, we elected not to proceed with plans to construct the Bakken Crude Express Pipeline due to insufficient long-term transportation commitments during the open season.

Cash Distributions - During 2012, we paid cash distributions totaling $2.59 per unit, an increase of approximately 11 percent over the $2.325 per unit paid during 2011. In January 2013, our general partner declared a cash distribution of $0.71 per unit ($2.84 per unit on an annualized basis) for the fourth quarter 2012, an increase of approximately 16 percent over the $0.61 declared in January 2012.

Debt Issuance - In September 2012, we completed an underwritten public offering of $1.3 billion of senior notes generating net proceeds of approximately $1.3 billion.

Equity Issuance - In March 2012, we completed an underwritten public offering of 8.0 million common units and also sold 8.0 million common units to ONEOK in a private placement, generating net proceeds of approximately $920 million. In conjunction with the issuances, ONEOK contributed approximately $19 million in order to maintain its 2-percent general partner interest in us.

We entered into an Equity Distribution Agreement (EDA) for the offer and sale from time to time of our common units up to an aggregate amount of $300 million. We are under no obligation to offer common units under the EDA. We intend to use the net proceeds from sales under the program for general partnership purposes.

FINANCIAL RESULTS AND OPERATING INFORMATION

Consolidated Operations

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

	Years Ended December 31,			Variances 2012 vs. 2011		Variances 2011 vs. 2010	
Financial Results	**2012**	**2011**	**2010**	**Increase (Decrease)**		**Increase (Decrease)**	
				(Millions of dollars)			
Revenues	**$ 10,182.2**	$ 11,322.6	$ 8,675.9	**$ (1,140.4)**	**(10)%**	$ 2,646.7	31%
Cost of sales and fuel	**8,540.4**	9,745.2	7,531.0	**(1,204.8)**	**(12)%**	2,214.2	29%
Net margin	**1,641.8**	1,577.4	1,144.9	**64.4**	**4 %**	432.5	38%
Operating costs	**482.5**	459.4	403.5	**23.1**	**5 %**	55.9	14%
Depreciation and amortization	**203.1**	177.5	173.7	**25.6**	**14 %**	3.8	2%
Gain (loss) on sale of assets	**6.7**	(1.0)	18.6	**7.7**	*****	(19.6)	*
Operating income	**$ 962.9**	$ 939.5	$ 586.3	**$ 23.4**	**2 %**	$ 353.2	60%
Equity earnings from investments	**$ 123.0**	$ 127.2	$ 101.9	**$ (4.2)**	**(3)%**	$ 25.3	25%
Allowance for equity funds used during construction	**$ 13.6**	$ 2.3	$ 1.0	**$ 11.3**	*****	$ 1.3	*
Interest expense	**$ (206.0)**	$ (223.1)	$ (204.3)	**$ (17.1)**	**(8)%**	$ 18.8	9%
Capital expenditures	**$ 1,560.5**	$ 1,063.4	$ 352.7	**$ 497.1**	**47 %**	$ 710.7	*

* Percentage change is greater than 100 percent.

<u>2012 vs. 2011</u> - Revenues for 2012, compared with the prior year, decreased due to lower net realized natural gas and NGL product prices, offset partially by higher natural gas and NGL sales volumes from our completed capital projects. The increase in natural gas supply resulting from the development of nonconventional resource areas in North America and a warmer than normal winter have caused lower natural gas prices and narrower natural gas location and seasonal price differentials in the markets we serve. NGL prices, particularly ethane and propane, also decreased in 2012 due primarily to increased NGL production growth from the development of NGL-rich areas. Propane prices also were affected by a warmer than normal winter. During the second half of 2012, NGL location price differentials also narrowed due to the strong production growth, increased demand in the Mid-Continent region and increased capacity available on pipelines that connect the Mid-Continent and Gulf Coast market centers.

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 not to recover the ethane component of the natural gas stream, also known as ethane rejection, and instead leave 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 periods of ethane rejection in the Mid-Continent and Rocky Mountain regions during 2012. Ethane rejection did not have a material impact on our financial results in 2012. We expect lower natural gas liquids volumes in our Natural Gas Liquids segment as a result of widespread and prolonged ethane rejection in 2013 that is expected to have a significant impact on our financial results. We do not expect prolonged ethane rejection to continue into 2014.

Operating income for the year, compared with the prior year, increased due to higher volumes from our completed projects in our Natural Gas Gathering and Processing and Natural Gas Liquids segments. The impact of the increase in volumes was offset partially by less favorable NGL price differentials and lower NGL transportation capacity available for optimization activities in our Natural Gas Liquids segment. Additionally, the increase was offset by higher compression and processing costs and lower realized natural gas and NGL product prices, particularly ethane and propane, compared with the prior year, in our Natural Gas Gathering and Processing segment.

Operating costs and depreciation and amortization increased for 2012, compared with the prior year, due primarily to the growth of our operations related to our completed capital projects.

Gain on sale of assets increased from a loss in 2011 due primarily to the sale of a natural gas pipeline lateral in our Natural Gas Pipelines segment.

Interest expense decreased for 2012, compared with the prior year, primarily as a result of higher interest capitalized associated with our investments in the growth projects in our Natural Gas Gathering and Processing and Natural Gas Liquids segments. The increase in interest expense resulting from the $1.3 billion issuance of senior notes in September 2012 was offset partially by the repayment of $350 million senior notes, which had a higher interest rate, in April 2012.

Capital expenditures and AFUDC increased for 2012, compared with the prior year, due primarily to the growth projects in our Natural Gas Liquids segment.

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

2011 vs. 2010 - NGL and condensate prices were higher while natural gas prices decreased during 2011, compared with 2010. These changes in commodity prices had a direct impact on our revenues and cost of sales and fuel.

Operating income increased approximately 60 percent during 2011, compared with 2010. The increase in operating income reflects higher net margin in our Natural Gas Liquids and Natural Gas Gathering and Processing segments.

Our Natural Gas Liquids segment benefited from more favorable NGL price differentials, as well as additional NGL fractionation and transportation capacity available for optimization activities between the Mid-Continent and Gulf-Coast markets. Our Natural Gas Liquids segment also realized higher exchange service margins due primarily to higher NGL gathering and fractionation volumes and contract renegotiations at higher fees with our customers. In addition, our Natural Gas Liquids segment realized higher isomerization margins resulting from wider price differentials between normal butane and iso-butane, and higher isomerization volumes.

Our Natural Gas Gathering and Processing segment benefited from significantly higher realized NGL and condensate prices, higher natural gas volumes processed and favorable changes in contract terms, offset partially by lower natural gas volumes gathered primarily in the Powder River Basin.

These increases were offset partially by the impact of the September 2010 deconsolidation of Overland Pass Pipeline Company, which is now accounted for under the equity method in our Natural Gas Liquids segment following the sale of a 49-percent ownership interest in Overland Pass Pipeline Company. Additionally, our Natural Gas Pipelines segment realized lower transportation margins due to narrower natural gas price location differentials that caused a reduction in contracted capacity primarily on Midwestern Gas Transmission.

Gain (loss) on sale of assets decreased from 2010, which reflected a $16.3 million gain on the sale of a 49-percent interest of Overland Pass Pipeline Company.

Operating costs increased for 2011, compared with 2010, due primarily to higher labor and employee-related costs associated with incentive and benefit plans, and higher ad valorem taxes, as well as higher materials and outside services expenses associated primarily with scheduled maintenance at our natural gas liquids fractionation and storage facilities. Our employees participate in compensation and benefit plans administered by ONEOK, which include ONEOK's short-term incentive and share-based compensation plans. ONEOK's share price significantly increased in 2011, resulting in increased employee-related costs to us.

Equity earnings from investments increased for 2011, compared with 2010, due to the impact of the September 2010 deconsolidation of Overland Pass Pipeline Company in our Natural Gas Liquids segment and increased contracted capacity on Northern Border Pipeline in our Natural Gas Pipeline segment.

Capital expenditures increased for 2011, compared with 2010, due primarily to growth projects in our Natural Gas Gathering and Processing and Natural Gas Liquids segments and the purchase of leased equipment at our Bushton Plant.

Natural Gas Gathering and Processing

Growth Projects - Our Natural Gas Gathering and Processing segment is investing approximately $2.1 billion to $2.3 billion in growth projects in the Williston Basin and Cana-Woodford Shale areas that will enable us to meet the rapidly growing needs of crude oil and natural gas producers in those areas.

Williston Basin Processing Plants and related projects - Our projects in this basin include five 100 MMcf/d natural gas processing facilities: the Garden Creek, Garden Creek II and Garden Creek III plants located in eastern McKenzie County, North Dakota, and the Stateline I and II plants located in western Williams County, North Dakota. We have acreage dedications of approximately 3.1 million acres supporting these plants. In addition, we are expanding and upgrading our existing natural gas gathering and compression infrastructure and also adding new well connections associated with these plants. The Garden Creek plant was placed in service in December 2011 and together with the related infrastructure cost approximately $360 million, excluding AFUDC. We expect construction costs, excluding AFUDC, for the Garden Creek II plant will be $310 million to $345 million, and for the Garden Creek III plant will be approximately $325 million to $360 million.   The Garden Creek II and Garden Creek III plants are expected to be in service during the third quarter 2014 and the first quarter 2015, respectively. Together, the Stateline I and II plants and related infrastructure projects are expected to cost approximately $560 million to $660 million, excluding AFUDC. The 100 MMcf/d Stateline I natural gas processing facility was placed into service in September 2012, and the 100 MMcf/d Stateline II natural gas processing facility is expected to be in service during the first quarter 2013.

We plan to invest $140 million to $160 million to construct a 270-mile natural gas gathering system and related infrastructure in Divide County, North Dakota. The new system will gather and deliver natural gas from producers in the Williston Basin to both of our Stateline natural gas processing facilities in western Williams County, North Dakota. We have secured long-term supply commitments from producers for this new system, which are structured with POP and fee-based contractual components. This project is expected to be completed in the third quarter 2013.

Cana-Woodford Shale projects - We plan to invest approximately $340 million to $360 million to construct a new 200 MMcf/d natural gas processing facility, the Canadian Valley plant, and related infrastructure in the Cana-Woodford Shale in Canadian County, Oklahoma, in close proximity to our existing natural gas transportation and natural gas liquids gathering pipelines. The additional natural gas processing infrastructure is necessary to accommodate increased production of NGL-rich natural gas in the Cana-Woodford Shale where we have substantial acreage dedications from active producers. The new Canadian Valley plant is expected to cost approximately $190 million, excluding AFUDC, and is expected to be in service in the first quarter 2014. The related additional infrastructure is expected to cost approximately $160 million, excluding AFUDC, which we expect will increase our capacity to gather and process natural gas to approximately 390 MMcf/d in the Cana-Woodford Shale.

In both the Williston Basin and Cana-Woodford Shale project areas, nearly all of the new gas production is from horizontally drilled and completed wells. Horizontal wells drilled in the Williston Basin are justified primarily by crude-oil economics, which are currently very favorable. These wells tend to produce at higher initial volumes 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. The routine growth capital needed to connect to new wells and expand our infrastructure is expected to increase compared with our historical levels of routine growth capital.

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 2012 operating results include the benefits from our completed growth projects. Operating results for 2012 reflect the completion of our Stateline I natural gas processing plant, which was placed in service in September 2012 and our Garden Creek natural gas processing plant, which was placed in service in December 2011. Placing these plants and their related infrastructure in service has resulted in increases in natural gas volumes gathered and processed in the Williston Basin. We expect drilling activities and development of the reserves to continue in the Bakken Shale and Three Forks formations in the Williston Basin and in the Cana-Woodford Shale and Granite Wash areas in Oklahoma and Texas. 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 2012 vs. 2011		Variances 2011 vs. 2010	
Financial Results	**2012**	**2011**	**2010**	**Increase (Decrease)**		**Increase (Decrease)**	
			(Millions of dollars)				
NGL and condensate sales	**$ 934.2**	$ 917.5	$ 722.6	**$ 16.7**	**2 %**	$ 194.9	27%
Residue gas sales	**403.8**	461.5	446.9	**(57.7)**	**(13)%**	14.6	3%
Gathering, compression, dehydration and processing fees and other revenue	**177.7**	154.5	148.4	**23.2**	**15 %**	6.1	4%
Cost of sales and fuel	**1,060.5**	1,130.6	966.5	**(70.1)**	**(6)%**	164.1	17%
Net margin	**455.2**	402.9	351.4	**52.3**	**13 %**	51.5	15%
Operating costs	**164.0**	153.7	136.8	**10.3**	**7 %**	16.9	12%
Depreciation and amortization	**83.0**	68.3	60.7	**14.7**	**22 %**	7.6	13%
Gain (loss) on sale of assets	**2.2**	(0.3)	(0.3)	**2.5**	*****	—	—%
Operating income	**$ 210.4**	$ 180.6	$ 153.6	**$ 29.8**	**17 %**	$ 27.0	18%
Equity earnings from investments	**$ 29.1**	$ 30.5	$ 27.5	**$ (1.4)**	**(5)%**	$ 3.0	11%
Capital expenditures	**$ 566.1**	$ 623.7	$ 216.0	**$ (57.6)**	**(9)%**	$ 407.7	*

* Percentage change is greater than 100 percent.

2012 vs. 2011 - Net margin increased primarily as a result of the following:

- an increase of $131.5 million due to volume growth in the Williston Basin from our new Garden Creek and Stateline I natural gas processing plants and increased drilling activity resulting in higher natural gas volumes gathered, compressed, processed, transported and sold, and higher fees; offset partially by
- a decrease of $38.1 million due primarily to higher compression costs and less favorable contract terms associated with our volume growth in the Williston Basin;
- a decrease of $31.4 million due to lower net realized natural gas and NGL prices, particularly ethane and propane; and
- a decrease of $5.9 million due to lower natural gas volumes gathered in the Powder River Basin as a result of continued declines in coal-bed methane production.

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

- an increase of $4.9 million in higher materials and supplies and outside service expenses;
- an increase of $2.1 million due to higher ad valorem taxes; and
- an increase of $1.5 million related to higher labor and employee-related costs.

Depreciation and amortization increased due to the completion of the Garden Creek and Stateline I natural gas processing plants in the Williston Basin and the completion of well connections and infrastructure projects supporting our volume growth in the Williston Basin.

Capital expenditures decreased due primarily to the timing of expenditures on our growth projects discussed above, offset partially by the completion of approximately 940 well connections in the Williston Basin and Mid-Continent areas in 2012, compared with approximately 600 well connections in 2011.

We expect capital expenditures to increase in 2013 as construction continues on our growth projects. See "Capital Expenditures" in "Liquidity and Capital Resources" for additional detail of our projected capital expenditures.

2011 vs. 2010 **-** Net margin increased primarily as a result of the following:

- an increase of $32.6 million due to higher net realized NGL and condensate prices;

- an increase of $19.4 million due to higher natural gas volumes processed in the Williston Basin and western Oklahoma resulting from increased drilling activity, offsetting reduced drilling activity in certain parts of Kansas and weather-related outages in the first quarter 2011;
- an increase of $8.8 million due to favorable changes in contract terms; and offset partially by
- a decrease of $8.2 million due to lower natural gas volumes gathered as a result of continued production declines and reduced drilling activity by producers in the Powder River Basin.

Operating costs increased due primarily to the following:

- an increase of $11.9 million of higher labor costs and employee-related costs associated with incentive and benefit plans; and
- an increase of $7.2 million in chemicals, material, supplies and outside services associated with the growth of our operations; offset partially by
- a reduction of $4.7 million in rental costs due to the termination of our Processing and Services Agreement with ONEOK when we acquired the previously leased equipment at the Bushton Plant in June 2011.

Depreciation and amortization increased due to both the completion of the connection of our western Oklahoma natural gas gathering system to our Maysville natural gas processing facility in central Oklahoma and the completion of well connections and infrastructure projects supporting our volume growth in the Williston Basin.

Capital expenditures increased due primarily to our growth projects discussed above and the completion of approximately 600 well connections in the Williston Basin and Mid-Continent areas in 2011, compared with approximately 300 well connections in 2010.

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)	**2012**	**2011**	**2010**
Natural gas gathered (*BBtu/d*)	**1,119**	1,030	1,067
Natural gas processed (*BBtu/d*) (b)	**866**	713	674
NGL sales (*MBbl/d*)	**61**	48	44
Residue gas sales (*BBtu/d*)	**397**	317	286
Realized composite NGL net sales price (*$/gallon*) (c)	**$ 1.06**	$ 1.08	$ 0.94
Realized condensate net sales price (*$/Bbl*) (c)	**$ 88.22**	$ 82.56	$ 63.81
Realized residue gas net sales price (*$/MMBtu*) (c)	**$ 3.87**	$ 5.47	$ 5.58
Realized gross processing spread (*$/MMBtu*) (c)	**$ 8.05**	$ 8.17	$ 6.41

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

Natural gas gathered volumes increased for 2012, compared with the prior year, due to increased drilling activity in the Williston Basin and western Oklahoma, completion of additional natural gas gathering lines and compression to support our new Garden Creek and Stateline I natural gas processing plants, offset partially by continued declines in coal-bed methane production in the Powder River Basin in Wyoming.

Natural gas gathered decreased for 2011, compared with 2010, due to continued production declines and reduced drilling activity, primarily in the Powder River Basin in Wyoming and certain parts of Kansas, and weather-related outages in the first quarter 2011, offset partially by increased drilling activity in the Williston Basin and western Oklahoma.

Natural gas processed and residue gas sales volumes increased for each of the comparable periods due to an increase in drilling activity in the Williston Basin and western Oklahoma, offsetting reduced drilling activity and natural production declines in Kansas.

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 the Powder River Basin. The reduced development activities and natural production declines in the Powder River Basin have resulted in lower natural gas volumes available to be gathered. While the reserve potential in the Powder River Basin still exists, future drilling and development will be affected by commodity prices and producers' alternative prospects. A continued decline in volumes gathered in this area may reduce our ability to recover the carrying value of our assets and equity investments in this area and could result in noncash charges to earnings.

The quantity and composition of NGLs received by our Natural Gas Gathering and Processing segment as payments under our various processing agreements continue to change as our new natural gas processing plants in the Williston Basin are placed in service. Our Garden Creek and Stateline I plants have the capability to recover ethane when economic conditions warrant but will not until our Natural Gas Liquids segment's Bakken NGL Pipeline is completed, which is expected to be in the first quarter 2013. As a result, our 2012 equity NGL volumes and realized composite NGL net sales price are weighted more toward the relatively higher priced propane, iso-butane, normal butane and natural gasoline compared with the prior year. This has the effect of producing a higher NGL composite barrel realized price, while most individual NGL products prices are substantially lower this year compared with the prior year.

	Years Ended December 31,		
Operating Information (a)	**2012**	**2011**	**2010**
Percent of proceeds			
NGL sales (*Bbl/d*) (b)	**9,803**	6,472	6,310
Residue gas sales (*MMBtu/d*) (b)	**65,205**	48,198	41,813
Condensate sales (*Bbl/d*) (b)	**2,104**	1,684	1,763
Percentage of total net margin	**64%**	61%	54%
Fee-based			
Wellhead volumes (*MMBtu/d*)	**1,118,693**	1,030,045	1,067,090
Average rate (*$/MMBtu*)	**$ 0.35**	$ 0.34	$ 0.31
Percentage of total net margin	**31%**	32%	35%
Keep-whole			
NGL shrink (*MMBtu/d*) (c)	**6,747**	10,131	13,545
Plant fuel (*MMBtu/d*) (c)	**757**	1,104	1,648
Condensate shrink (*MMBtu/d*) (c)	**904**	1,082	1,433
Condensate sales (*Bbl/d*)	**183**	219	290
Percentage of total net margin	**5%**	7%	11%

(a) - Includes volumes for consolidated entities only.
(b) - Represents equity volumes.
(c) - Refers to the Btus that are removed from natural gas through processing.

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. A small percentage of our services, based on volume, are provided through keep-whole contracts. See discussion regarding our commodity price risk under "Commodity Price Risk" in Item 7A, Quantitative and Qualitative Disclosures about Market Risk.

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, 2012	2011	2010	Variances 2012 vs. 2011 Increase (Decrease)		Variances 2011 vs. 2010 Increase (Decrease)	
	(Millions of dollars)						
Transportation revenues	**$ 220.9**	$ 233.6	$ 244.2	**$ (12.7)**	**(5)%**	$ (10.6)	(4)%
Storage revenues	**68.7**	68.8	67.8	**(0.1)**	**— %**	1.0	1 %
Gas sales and other revenues	**30.8**	35.4	39.1	**(4.6)**	**(13)%**	(3.7)	(9)%
Cost of sales	**34.3**	53.4	50.9	**(19.1)**	**(36)%**	2.5	5 %
Net margin	**286.1**	284.4	300.2	**1.7**	**1 %**	(15.8)	(5)%
Operating costs	**101.9**	108.6	96.5	**(6.7)**	**(6)%**	12.1	13 %
Depreciation and amortization	**45.7**	45.4	44.1	**0.3**	**1 %**	1.3	3 %
Gain (loss) on sale of assets	**5.3**	(0.3)	3.4	**5.6**	*****	(3.7)	*
Operating income	**$ 143.8**	$ 130.1	$ 163.0	**$ 13.7**	**11 %**	$ (32.9)	(20)%
Equity earnings from investments	**$ 73.2**	$ 76.9	$ 68.8	**$ (3.7)**	**(5)%**	$ 8.1	12 %
Capital expenditures	**$ 25.4**	$ 37.8	$ 27.6	**$ (12.4)**	**(33)%**	$ 10.2	37 %

* Percentage change is greater than 100 percent.

2012 vs. 2011 - Net margin remained relatively unchanged as a result of the following:

- an increase of $3.3 million due to higher contracted capacity in western Oklahoma and the Texas panhandle on our intrastate pipelines to transport increasing natural gas supply to market, offset partially by lower negotiated rates on Midwestern Gas Transmission; offset by
- a decrease of $1.0 million due primarily to lower prices on our net retained fuel position.

Operating costs decreased primarily as a result of reduced employee-related costs associated with incentive and benefit plans.

Gain (loss) on sale of assets increased from 2011, due to a $5.7 million gain on the sale of a natural gas pipeline lateral.

Equity earnings from our investments decreased due primarily to increased maintenance expenses at Northern Border Pipeline.

2011 vs. 2010 **-** Net margin decreased primarily as a result of the following:

- a decrease of $12.5 million from lower natural gas transportation margins due to narrower natural gas price location differentials that decreased contracted transportation capacity primarily on Midwestern Gas Transmission and interruptible transportation volumes across our pipelines; and
- a decrease of $5.0 million due primarily to lower prices on our net retained fuel position.

Operating costs increased primarily as a result of the following:

- an increase of $6.7 million due to higher labor costs and employee-related costs associated with incentive and benefit plans; and
- an increase of $1.4 million due to higher ad valorem taxes associated with our completed capital projects.

Equity earnings from investments increased due primarily to increased contracted capacity on Northern Border Pipeline resulting from wider natural gas price location differentials between the markets it serves.

Operating Information (a)	Years Ended December 31, 2012	2011	2010
Natural gas transportation capacity contracted *(MDth/d)*	**5,366**	5,373	5,616
Transportation capacity subscribed (b)	**89%**	89%	93%
Average natural gas price			
Mid-Continent region (*$/MMBtu*)	**$ 2.64**	$ 3.88	$ 4.17

(a) - Includes volumes for consolidated entities only.
(b) - Prior periods have been recast to reflect current estimated capacity.

Natural gas transportation capacity contracted decreased in 2011 compared with 2010 due primarily to lower subscribed capacity on Midwestern Gas Transmission due to narrower natural gas price location differentials between the markets it serves.

Our pipelines primarily serve end-users such as natural gas distribution companies and electric-generation companies that require natural gas to operate their businesses regardless of location price differentials. The development of shale gas and other resource areas has continued to increase available natural gas supply and has caused natural gas prices to decrease and location and seasonal price differentials to narrow. 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 if they were to 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 in the future as the development of shale and other resource areas continue.

In November 2012, the FERC initiated a review of Viking Gas Transmission's rates pursuant to Section 5 of the Natural Gas Act. The review is currently in process, and while the ultimate outcome cannot be predicted, it could result in a future reduction of rates. We do not expect the ultimate outcome to impact materially our results of operations.

Our operating information above does not include our 50-percent interest in Northern Border Pipeline. Substantially all of Northern Border Pipeline's long-haul transportation capacity has been contracted through March 2014. 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, which is expected to reduce our future equity earnings and cash distributions from Northern Border Pipeline.

Natural Gas Liquids

Growth Projects - Our growth strategy in the Natural Gas Liquids segment is focused around the crude oil and NGL-rich natural gas drilling activity in shale and other unconventional resource areas from the Rocky Mountain region through the Mid-Continent region into Texas. Increasing crude oil, natural gas and NGL production resulting from this activity and higher petrochemical industry demand for NGL products have required 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 three to five years, and international demand for propane is expected to impact positively the NGL market in the future.

Our Natural Gas Liquids segment is investing approximately $2.6 billion to $3.0 billion in NGL-related projects through 2015. 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 capacity used historically to capture the NGL price differentials between the two market centers. During the second half of 2012, NGL price differentials narrowed between the Mid-Continent and Gulf Coast market centers. We expect these narrow NGL price differentials to continue as new fractionators and pipelines, including our growth projects discussed below, continue to alleviate constraints between the two market centers.

Sterling III Pipeline - We are in the process of constructing a 540-plus-mile natural gas liquids pipeline, the Sterling III Pipeline, which will have the flexibility to transport either unfractionated NGLs or NGL products from the Mid-Continent to the Gulf Coast. The Sterling III Pipeline will traverse the NGL-rich Woodford Shale that is currently under development, as well as provide transportation capacity for the growing NGL production from the Cana-Woodford Shale and Granite Wash areas, where the pipeline can gather unfractionated NGLs from the new natural gas processing plants that are being built as a result of increased drilling activity in these areas. The Sterling III Pipeline will have an initial capacity to transport up to 193 MBbl/d of production from our natural gas liquids infrastructure at Medford, Oklahoma, to our storage and fractionation facilities in Mont Belvieu, Texas. We have multi-year 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 250 MBbl/d. Following the receipt of all necessary permits and the acquisition of rights-of-way, construction is scheduled to begin in 2013, with an expected completion late this year.

The project also includes reconfiguration of our existing Sterling I and II pipelines, which distribute NGL products between the Mid-Continent and Gulf Coast natural gas liquids market centers, to transport either unfractionated NGLs or NGL products. The project costs for the new pipeline and reconfiguration projects are estimated to be $610 million to $810 million, excluding AFUDC.

MB-2 Fractionator - We are constructing a new 75 MBbl/d fractionator, MB-2, near our storage facility in Mont Belvieu, Texas. Construction began in June 2011 and is expected to be completed in mid-2013. The cost of the new fractionator is estimated to be $300 million to $390 million, excluding AFUDC. We have multi-year supply commitments from producers and natural gas processors for all of the fractionator's capacity.

MB-3 Fractionator - We also announced plans to construct a 75 MBbl/d fractionator, MB-3, near our storage facility in Mont Belvieu, Texas. In addition, we plan to expand and upgrade our existing natural gas liquids gathering and pipeline infrastructure, including new connections to natural gas processing facilities and increasing the capacity of the Arbuckle and Sterling II natural gas liquids pipelines. The MB-3 fractionator and related infrastructure are expected to cost approximately $525 million to $575 million, excluding AFUDC. The MB-3 fractionator is expected to be completed in the fourth quarter 2014. Supply commitments from third-party natural gas processors are in various stages of negotiation.

Ethane/Propane Splitter - Additionally, we announced plans to construct a new 40 MBbl/d ethane/propane splitter at our Mont Belvieu storage facility to split ethane/propane mix into purity ethane in order to meet the growing needs of petrochemical customers. The facility will be capable of producing 32 MBbl/d of purity ethane and 8 MBbl/d of propane, and is expected to be in service during the second quarter 2014. The ethane/propane splitter is expected to cost approximately $45 million, excluding AFUDC.

Bakken NGL Pipeline and related projects - We are building an approximately 600-mile natural gas liquids pipeline, the Bakken NGL Pipeline, to transport unfractionated NGLs from the Williston Basin to the Overland Pass Pipeline. We also announced plans to invest an additional $100 million to install additional pump stations on the Bakken NGL Pipeline to increase its capacity to 135 MBbl/d from an initial capacity of 60 MBbl/d. The unfractionated NGLs then will be delivered to our existing natural gas liquids fractionation and distribution infrastructure in the Mid-Continent. Project costs for the new pipeline, including the expansion, are estimated to be $550 million to $650 million, excluding AFUDC. NGL supply commitments for the Bakken NGL Pipeline are anchored by NGL production from our natural gas processing plants. The 12-inch diameter pipeline is expected to be in service during the first quarter 2013, and the expansion is expected to be completed in the third quarter 2014.

The unfractionated NGLs from the Bakken NGL Pipeline and other supply sources under development in the Rocky Mountain region will require installing additional pump stations and expanding existing pump stations on the Overland Pass Pipeline in which we own a 50-percent equity interest. These additions and expansions will increase the capacity of the Overland Pass Pipeline to 255 MBbl/d. Our anticipated share of the costs for this project is estimated to be $35 million to $40 million, excluding AFUDC.

Bushton Fractionator expansion - In September 2012, we completed an expansion and upgrade to our existing NGL fractionation capacity at Bushton, Kansas, increasing capacity to 210 MBbl/d from 150 MBbl/d. This additional capacity is necessary to accommodate the volume growth from the Mid-Continent and Williston Basin. The project cost approximately $117 million, excluding AFUDC.

New NGL pipeline and modification of Hutchinson fractionation infrastructure - We plan to invest approximately $140 million, excluding AFUDC, to construct a new 95-mile natural gas liquids pipeline that will connect our existing NGL fractionation and storage facilities in Hutchinson, Kansas, to similar facilities in Medford, Oklahoma. These projects also include related modifications to existing natural gas liquids fractionation infrastructure at Hutchinson, Kansas, to accommodate additional unfractionated NGLs produced in the Williston Basin. The pipeline and related modifications are expected to be in service during the first quarter 2015.

Cana-Woodford Shale and Granite Wash projects - We constructed approximately 230 miles of natural gas liquids pipelines that expanded our existing Mid-Continent natural gas liquids gathering system in the Cana-Woodford Shale and Granite Wash areas. These pipelines expanded our capacity to transport unfractionated NGLs from these Mid-Continent supply areas to fractionation facilities in Oklahoma and Texas and distribute NGL products to the Mid-Continent, Gulf Coast and upper Midwest market centers. The pipelines are connected to three new third-party natural gas processing facilities and to three existing third-party natural gas processing facilities that were expanded. Additionally, we installed additional pump stations on our Arbuckle Pipeline to increase its capacity to 240 MBbl/d. These projects are expected to add, through multi-year supply contracts, approximately 75 to 80 MBbl/d of unfractionated NGLs, to our existing natural gas liquids gathering systems. These projects were placed in service in April 2012 and cost approximately $220 million, excluding AFUDC.

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

Selected Financial Results and Operating Information - Our Natural Gas Liquids segment's 2012 operating results reflect the benefits from the following completed growth projects:

- the expansion of our Bushton fractionator, which was placed in service in September 2012;
- the expansion of our Mid-Continent natural gas liquids gathering system in the Cana-Woodford Shale and Granite Wash areas, which was placed in service in April 2012;
- additional Gulf Coast fractionation capacity made available by our 60 Mbl/d fractionation agreement with Targa Resources Partners that began in the second quarter 2011; and
- the expansion of our Sterling I natural gas liquids distribution pipeline, which was placed in service in the fourth quarter 2011.

These projects have resulted in increases in natural gas liquids volumes gathered, fractionated and transported across our natural gas liquids systems. 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 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 2012 vs. 2011		Variances 2011 vs. 2010	
Financial Results	**2012**	**2011**	**2010**	**Increase (Decrease)**		**Increase (Decrease)**	
			(Millions of dollars)				
NGL and condensate sales	**$ 8,479.7**	$ 9,764.2	$ 7,219.0	**$ (1,284.5)**	**(13)%**	$ 2,545.2	35 %
Exchange service and storage revenues	**707.6**	531.6	470.9	**176.0**	**33 %**	60.7	13 %
Transportation revenues	**69.3**	65.5	85.1	**3.8**	**6 %**	(19.6)	(23)%
Cost of sales and fuel	**8,349.3**	9,469.5	7,275.4	**(1,120.2)**	**(12)%**	2,194.1	30 %
Net margin	**907.3**	891.8	499.6	**15.5**	**2 %**	392.2	79 %
Operating costs	**223.8**	198.9	173.9	**24.9**	**13 %**	25.0	14 %
Depreciation and amortization	**74.3**	63.9	68.9	**10.4**	**16 %**	(5.0)	(7)%
Gain (loss) on sale of assets	**(1.0)**	(0.4)	15.5	**(0.6)**	*****	(15.9)	*
Operating income	**$ 608.2**	$ 628.6	$ 272.3	**$ (20.4)**	**(3)%**	$ 356.3	*
Equity earnings from investments	**$ 20.7**	$ 19.9	$ 5.6	**$ 0.8**	**4 %**	$ 14.3	*
Allowance for equity funds used during construction	**$ 13.5**	$ 2.1	$ 0.9	**$ 11.4**	*****	$ 1.2	*
Capital expenditures	**$ 968.5**	$ 401.3	$ 107.9	**$ 567.2**	*****	$ 293.4	*

* Percentage change is greater than 100 percent.

<u>2012 vs. 2011</u> - NGL prices, particularly ethane and propane, decreased in 2012 due primarily to increased NGL production from the development of NGL-rich areas and lower crude-oil prices. During the second half of 2012, due to strong NGL production 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, NGL price differentials narrowed between the Mid-Continent market center at Conway, Kansas, and the Gulf Coast market center at Mont Belvieu, Texas.

Net margin increased primarily as a result of the following:

- an increase of $101.5 million related to higher NGL volumes gathered and fractionated across our systems related to completion of certain growth projects and contract renegotiations for higher fees associated with our NGL exchange services activities; and
- an increase of $13.1 million due to higher natural gas liquids storage margins as a result of contract renegotiations at higher fees; offset partially by

- a decrease of $91.2 million in optimization and marketing margins, which resulted from a $94.6 million decrease due to narrower NGL price differentials and reduced transportation capacity available for optimization activities, as an increasing portion of our transportation capacity between the Conway, Kansas, and Mont Belvieu, Texas, NGL market centers was utilized by our exchange services activities to produce fee-based earnings. This decrease was offset partially by a $3.5 million increase in our marketing activities that benefited from higher natural gas liquids truck and rail volumes;
- a decrease of $4.5 million due to the impact of higher operational measurement losses; and
- a decrease of $3.4 million related to lower isomerization margins resulting from lower isomerization volumes.

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

- an increase of $16.1 million due to higher material and outside services expenses, including costs associated with scheduled maintenance at our existing facilities;
- an increase of $3.8 million due to higher labor and employee-related costs; and
- an increase of $1.8 million due to higher ad valorem taxes.

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

Capital expenditures and the allowance for equity funds used during construction increased due primarily to our growth projects discussed above.

<u>2011 vs. 2010</u> **-** NGL prices and price differentials between Conway, Kansas, and Mont Belvieu, Texas, were wider during 2011, compared with 2010. The increase in NGL prices and location price differentials had a significant impact on our revenues and cost of sales and fuel.

Net margin increased primarily as a result of the following:

- an increase of $363.6 million in optimization and marketing margins due primarily to the following:
  - an increase of $335.2 million from more favorable NGL price differentials and additional fractionation and transportation capacity available for optimization activities between the Conway, Kansas, and Mont Belvieu, Texas, NGL market centers; and
  - an increase of $28.4 million from higher marketing volumes and more favorable margins on NGL products marketed;
- an increase of $32.5 million related to higher NGL volumes gathered and fractionated in Texas and the Mid-Continent and Rocky Mountain regions, excluding the impact of the September 2010 deconsolidation of Overland Pass Pipeline Company, and contract renegotiations for higher fees associated with our NGL exchange services activities, offset partially by higher costs associated with NGL volumes fractionated by third parties;
- an increase of $26.4 million related to higher isomerization margins resulting from wider price differentials between normal butane and iso-butane, and higher isomerization volumes; and
- an increase of $12.4 million due to higher storage margins as a result of contract renegotiations at higher fees; offset partially by
- a decrease of $42.8 million due to the deconsolidation of Overland Pass Pipeline Company, which is now accounted for under the equity method.

Operating costs increased primarily as a result of the following:

- an increase of $17.1 million due to higher labor costs and employee-related costs associated with incentive and benefit plans, which includes higher equity-based compensation costs;
- an increase of $9.4 million from higher materials and outside services expenses associated primarily with scheduled maintenance at our fractionation, pipeline and storage facilities; and
- an increase of $3.6 million from higher ad valorem taxes as a result of our completed capital projects; offset partially by
- a decrease of $5.4 million due to the deconsolidation of Overland Pass Pipeline Company, which is now accounted for under the equity method.

Depreciation and amortization expense decreased due primarily to the deconsolidation of Overland Pass Pipeline Company, which is now accounted for under the equity method, offset partially by depreciation associated with our completed capital projects.

Equity earnings increased due primarily to the deconsolidation of Overland Pass Pipeline Company, which is now accounted for under the equity method.

Gain (loss) on sale of assets decreased due primarily to the $16.3 million gain on sale of a 49-percent ownership interest in Overland Pass Pipeline Company recorded in 2010.

Capital expenditures increased due primarily to the purchase of leased equipment at our Bushton Plant and expenditures related to our growth projects discussed above.

Previously, we had a Processing and Services Agreement with ONEOK and OBPI, under which we contracted for all of OBPI's rights, including all of the capacity of the Bushton Plant, reimbursing OBPI for all costs associated with the operation and maintenance of the Bushton Plant and its obligations under equipment leases covering portions of the Bushton Plant. On June 30, 2011, we acquired OBPI and terminated the equipment lease agreements. The total amount paid by us to complete the transactions was approximately $94.2 million, which included the reimbursement to ONEOK of obligations related to the Processing and Services Agreement.

	Years Ended December 31,		
Operating Information	**2012**	**2011**	**2010**
NGL sales (*MBbl/d*)	**572**	497	457
NGLs fractionated (*MBbl/d*) (a)	**574**	537	512
NGLs transported-gathering lines (*MBbl/d*) (b) (c)	**520**	436	440
NGLs transported-distribution lines (*MBbl/d*) (b)	**491**	473	468
Average Conway-to-Mont Belvieu OPIS price differential - ethane in ethane/propane mix (*$/gallon*)	**$ 0.17**	$ 0.28	$ 0.10

(a) Includes volumes fractionated at company-owned and third-party facilities.
(b) Includes volumes for consolidated entities only.
(c) 2010 volume information includes 62 MBbl/d related to Overland Pass Pipeline Company, which was deconsolidated in September 2010.

<u>2012 vs. 2011</u> - NGLs gathered and fractionated increased due primarily to increased throughput from existing connections in Texas and the Mid-Continent and Rocky Mountain regions, and new supply connections in the Mid-Continent and Rocky Mountain regions. The increased gathering capacity in the Mid-Continent region and Texas was made available through our Cana-Woodford Shale and Granite Wash projects, which were placed in service in April 2012. The increased Gulf Coast fractionation capacity was made available by our 60 Mbl/d fractionation services agreement with Targa Resources Partners that began in the second quarter 2011.

NGLs transported on distribution lines increased due primarily to our Sterling I pipeline expansion and higher volumes transported on our distribution pipelines between our Mid-Continent facilities to optimize the delivery of supply.

<u>2011 vs. 2010</u> - NGLs gathered and fractionated, excluding the impact of the September 2010 deconsolidation of Overland Pass Pipeline Company, increased due primarily to increased throughput through existing connections in Texas and the Mid-Continent and Rocky Mountain regions, and new supply connections in the Mid-Continent and Rocky Mountain regions. In second quarter 2011, additional Gulf Coast fractionation capacity became available through our 60MBbl/d fractionation service agreement with Targa Resources Partners.

NGLs transported on distribution lines increased primarily due to increased NGL product volumes transported on our North System pipeline to Midwest markets and our Sterling I pipeline expansion discussed above.

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 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 liquidity.

LIQUIDITY AND CAPITAL RESOURCES

General - Part of our strategy is to grow through internally generated growth projects and acquisitions that strengthen and complement our existing assets. We have relied primarily on operating cash flow, 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 flow. Capital expenditures are funded by operating cash flow, 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.

During 2012, we utilized cash from operations, our commercial paper program and proceeds from our March 2012 equity issuance and September 2012 debt issuance to fund our short-term liquidity needs, to repay our $350 million, 5.9-percent senior notes due April 2012 and to fund our capital projects as part of our long-term financing plan. See discussion below under "Long-term Financing" for more information.

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.

Capital Structure - The following table sets forth our capitalization structure for the periods indicated:

	December 31,	
	2012	**2011**
Long-term debt	**52%**	53%
Equity	**48%**	47%
Debt (including notes payable)	**52%**	53%
Equity	**48%**	47%

Cash Management - We use a centralized cash management program that concentrates the cash assets of our operating subsidiaries in joint accounts for the purpose 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 and our commercial paper program, which is supported by our Partnership Credit Agreement.

The total amount of short-term borrowings authorized by our general partner's Board of Directors is $2.5 billion. At December 31, 2012, we had no commercial paper outstanding, no letters of credit issued and no borrowings outstanding under our Partnership Credit Agreement. At December 31, 2012, we had approximately $537.1 million of cash and $1.2 billion of credit available under the Partnership Credit Agreement. As of December 31, 2012, we could have issued $3.2 billion of short- and long-term debt to meet our liquidity needs under the most restrictive provisions contained in our various borrowing agreements. Based on the forward LIBOR curve, we expect the interest rates on our short-term borrowings to increase in 2013, compared with interest rates on amounts during 2012.

Our Partnership Credit Agreement contains certain financial, operational and legal covenants. Among other things, these covenants include maintaining a ratio of indebtedness to adjusted EBITDA (EBITDA, as defined in our Partnership Credit Agreement, adjusted for all noncash charges and increased for projected EBITDA from certain lender-approved capital expansion projects) of no more than 5.0 to 1. If we consummate one or more acquisitions in which the aggregate purchase price is $25 million or more, the allowable ratio of indebtedness to adjusted EBITDA will increase to 5.5 to 1 for the quarter of the acquisition and the two following quarters. Upon breach of certain covenants by us in our Partnership Credit Agreement, amounts outstanding under our Partnership Credit Agreement, if any, may become due and payable immediately. At December 31, 2012, our ratio of indebtedness to adjusted EBITDA was 3.0 to 1, and we were in compliance with all covenants under our Partnership Credit Agreement.

Our Partnership Credit Agreement includes a $100 million sublimit for the issuance of standby letters of credit and also features an option that allows us to request an increase in the size of the facility to an aggregate of $1.7 billion from $1.2 billion by either commitments from new lenders or increased commitments from existing lenders. Our Partnership Credit Agreement is available for general partnership purposes, including repayment of our commercial paper notes, if necessary. Amounts outstanding under our commercial paper program reduce the borrowing capacity under our Partnership Credit Agreement.

Effective August 1, 2012, we extended the maturity date of our Partnership Credit Agreement to August 1, 2017, from August 1, 2016, pursuant to an extension agreement between us and the lenders.

Recent events in the European economy could impact European banks. Various European-based banks participate in our Partnership Credit Agreement, representing an aggregate of $342 million in committed capacity. These banks are of significant scale and international diversification, which we believe minimizes the risk of these banks being unable to fulfill their commitments to us under the Partnership Credit Agreement. Should any of these banks be unable to fund any future borrowings under our credit agreement, we believe other funding sources would likely be available to replace the commitments of the European banks in our Partnership Credit Agreement.

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 leaseback of facilities.

We are 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 existing credit facility, 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>Equity issuance</u> - 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 contributed approximately $19 million in order to maintain its 2-percent general partner interest in us. The net proceeds from the issuances were used 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 April 2012 and for other general partnership purposes, including capital expenditures. As a result of these transactions, ONEOK's aggregate ownership interest increased to 43.4 percent from 42.8 percent.

We entered into an EDA for the issue and sale from time to time of our common units up to an aggregate amount of $300 million. The EDA allows us to issue and sell our common units at prices we deem appropriate through a sales agent. Sales of common units, if any, will be 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 EDA. We intend to use the net proceeds from sales under the program for general partnership purposes.

<u>Debt issuance and maturity</u> - In September 2012, we completed an underwritten public offering 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 $1.3 billion was used to repay amounts outstanding under our commercial paper program, and the balance will be 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.

In January 2011, we completed an underwritten public offering of senior notes, consisting of $650 million of 3.25-percent senior notes due 2016 and $650 million of 6.125-percent senior notes due 2041. The net proceeds from the offering were approximately $1.3 billion and were used to repay amounts outstanding under our commercial paper program, to repay the $225 million principal amount of senior notes due March 2011 and for general partnership purposes, including capital expenditures.

<u>Debt covenants</u> - 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. Our senior notes are senior unsecured obligations, ranking equally in right of payment with all of our existing and future unsecured senior indebtedness, and structurally subordinate to any of the existing and future debt and other liabilities of any nonguarantor subsidiaries.

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, 2011, we had interest-rate swaps with notional values totaling $750 million. During 2012, we entered into additional interest-rate swaps with notional amounts totaling $650 million. Upon our debt issuance in September 2012, we settled $1.0 billion of our interest-rate swaps and realized a loss of $124.9 million in accumulated other comprehensive income (loss) that will be amortized to interest expense over the term of the related debt. At December 31, 2012, our remaining interest-rate swaps with notional amounts totaling $400 million have settlement dates greater than 12 months.

Capital Expenditures - We classify expenditures that are expected to generate additional revenue or significant operating efficiencies as growth capital expenditures. Maintenance capital expenditures are those required to maintain existing operations and do not generate additional revenues. Our capital expenditures are financed typically through operating cash flows, short- and long-term debt and the issuance of equity.

Capital expenditures were $1,560.5 million, $1,063.4 million and $352.7 million for 2012, 2011 and 2010, respectively. Capital expenditures increased for 2012, compared with 2011, due primarily to growth projects in our Natural Gas Liquids segment. Capital expenditures in 2011 were significantly greater than 2010 capital expenditures, due primarily growth projects in our Natural Gas Gathering and Processing and Natural Gas Liquids segments and the purchase of leased equipment at our Bushton Plant.

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

Growth Capital Expenditures	**2012**	**2011**	**2010**
		(Millions of dollars)	
Natural Gas Gathering and Processing	**$ 544.7**	$ 599.0	$ 198.4
Natural Gas Pipelines	**1.2**	9.2	6.1
Natural Gas Liquids	**912.4**	361.2	85.7
Total growth capital expenditures	**$ 1,458.3**	$ 969.4	$ 290.2

Maintenance Capital Expenditures	**2012**	**2011**	**2010**
		(Millions of dollars)	
Natural Gas Gathering and Processing	**$ 21.4**	$ 24.7	$ 17.6
Natural Gas Pipelines	**24.2**	28.6	21.5
Natural Gas Liquids	**56.1**	40.1	22.2
Other	**0.5**	0.6	1.2
Total maintenance capital expenditures	**$ 102.2**	$ 94.0	$ 62.5

The following table summarizes our 2013 projected growth and maintenance capital expenditures, excluding AFUDC:

2013 Projected Capital Expenditures		Growth		Maintenance		Total
				(Millions of dollars)		
Natural Gas Gathering and Processing	$	1,000	$	25	$	1,025
Natural Gas Pipelines		20		30		50
Natural Gas Liquids		1,500		60		1,560
Other		—		5		5
Total projected capital expenditures	$	2,520	$	120	$	2,640

Projected 2013 capital expenditures are significantly higher than 2012 capital expenditures due to the growth capital expenditures discussed in "Growth Projects" in the Natural Gas Gathering and Processing and Natural Gas Liquids segments in Financial Results and Operating Information. We are investing in projects totaling approximately $4.7 billion to $5.3 billion between 2011 and 2015. 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. The Northern Border Pipeline Management Committee has adopted a cash distribution policy related to financial ratio targets and capital contributions. The cash distribution policy defines minimum equity-to-total-capitalization ratios to be used by the Northern Border Pipeline Management Committee to establish the timing and amount of required capital contributions. In addition, any shortfall due to the inability to refinance maturing debt will be funded by capital contributions.

Credit Ratings - Our credit ratings as of December 31, 2012, 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 A2 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. The most common criteria for assessment of our credit ratings are the debt-to-EBITDA ratio, interest coverage, business risk profile and liquidity. We do not anticipate a downgrade in our credit ratings; however, if our credit ratings were downgraded, our cost to borrow funds under our commercial paper program and 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. An adverse rating change alone is not a default under our Partnership Credit Agreement. See additional discussion about our credit ratings under "Long-term Financing."

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.

Cash Distributions - We distribute 100 percent of our available cash, as defined in our Partnership Agreement, which 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 for 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 interests, during the periods indicated:

	Years Ended December 31,		
	2012	2011	2010
	(Millions of dollars)		
Common unitholders	**$ 370.5**	$ 304.2	$ 285.7
Class B unitholders	**189.0**	169.7	162.8
General partner	**201.4**	135.6	114.7
Noncontrolling interests	**0.8**	0.6	1.0
Total cash distributions paid	**$ 761.7**	$ 610.1	$ 564.2

For the years ended December 31, 2012, 2011 and 2010, cash distributions paid to our general partner included incentive distributions of $186.1 million, $123.4 million and $103.5 million, respectively.

In January 2013, our general partner declared a cash distribution of $0.71 per unit ($2.84 per unit on an annualized basis) for the fourth quarter of 2012, which was paid on February 14, 2013, to unitholders of record as of January 31, 2013.

Additional information about our cash distributions is included under 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 impact 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. 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.

ENVIRONMENTAL MATTERS

Information about our environmental matters is included in "Environmental and Safety Matters" of Item 1, Business, and Note M of the Notes to Consolidated Financial Statements in this Annual Report. We cannot ensure that existing environmental statutes and 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 could have a material adverse effect on our business, financial condition and results of operations. 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 did not have a material impact on earnings or cash flows during 2012, 2011 and 2010.

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 may not result in actual cash receipts or payments during the period. 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,		
	2012	**2011**	**2010**
	(Millions of dollars)		
Total cash provided by (used in):			
Operating activities	**$ 946.1**	$ 1,129.7	$ 495.2
Investing activities	**(1,545.2)**	(1,103.1)	92.3
Financing activities	**1,101.1**	7.6	(589.7)
Change in cash and cash equivalents	**502.0**	34.2	(2.2)
Cash and cash equivalents at beginning of period	**35.1**	0.9	3.1
Cash and cash equivalents at end of period	**$ 537.1**	$ 35.1	$ 0.9

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.

2012 vs. 2011 - Cash flows from operating activities, before changes in operating assets and liabilities, were $1.1 billion for 2012, compared with $1.0 billion for 2011. The increase was due primarily to an increase in net margin as discussed in "Financial Results and Operating Information" offset partially by decreased distributed earnings from our unconsolidated affiliates.

The changes in operating assets and liabilities decreased operating cash flows $129.3 million for 2012, compared with an increase of $112.7 million for 2011. The change is due primarily to the increase in natural gas liquids volumes in storage, offset partially by lower commodity prices. The change is also due to the change in accounts receivable resulting from the timing of cash receipts from customers, the change in accounts payable resulting from the timing of payments to vendors and suppliers, which vary from period to period, and the settlement of our interest-rate swaps associated with our $1.3 billion debt issuance in September 2012.

2011 vs. 2010 - Cash flows from operating activities, before changes in operating assets and liabilities, were $1,017.0 million for 2011, compared with $633.3 million for 2010. The increase was due primarily to an increase in net margin as discussed in "Financial Results and Operating Information" and higher distributed earnings from our unconsolidated affiliates.

The changes in operating assets and liabilities increased operating cash flows $112.7 million for 2011, compared with a decrease of $138.1 million for 2010. The change was due largely to the change in accounts receivable resulting from higher revenues and the timing of invoicing customers and receipt of cash, as well as accounts payable and the timing of the receipt of invoices from and payments to vendors and suppliers, which vary from period to period. Additionally, we had a decrease in volumes of NGLs in storage in the current period compared with an increase in volumes in storage during 2010 in our Natural Gas Liquids segment.

Investing Cash Flows - Cash used in investing activities increased for 2012, compared with 2011, due primarily to increased capital expenditures for our growth projects in our Natural Gas Liquids segment.

Cash used in investing activities increased for 2011, compared with 2010, due primarily to increased capital expenditures on our growth projects in our Natural Gas Gathering and Processing and Natural Gas Liquids segments, the purchase of leased equipment at our Bushton Plant, contributions made to Northern Border Pipeline and proceeds from the sale of a 49-percent interest in Overland Pass Pipeline Company in 2010.

Financing Cash Flows - Cash provided by financing activities increased during 2012, compared with 2011. The change is a result of net proceeds of $938.5 million from our equity issuances in 2012, partially offset by a $350 million debt maturity and higher cash distributions, compared with the same period in 2011, which included a $225 million debt maturity and a net repayment of $430 million of commercial paper. Financing cash flows also reflect net proceeds from our debt issuances of $1.3 billion in both 2012 and 2011.

Cash provided by financing activities increased during 2011, compared with 2010. The change was a result of our January 2011 debt issuance, a portion of the proceeds from which were used to repay short-term borrowings and the scheduled maturity of long-term debt. The remainder of the proceeds were used to fund our capital projects and for general partnership purposes. Additionally, we paid increased distributions to our general and limited partners as a result of increased available cash.

REGULATORY

Financial Markets Legislation - The Dodd-Frank Act represents a far-reaching overhaul of the framework for regulation of United States financial markets. Various regulatory agencies, including the SEC and the CFTC, have proposed regulations for implementation of many of the provisions of the Dodd-Frank Act. The CFTC has issued final regulations for many provisions of the Dodd-Frank Act that have varying effective dates for compliance, but others remain outstanding. Based on our assessment of the regulations issued to date and those proposed, we expect to be able to continue to participate in financial markets for hedging certain risks inherent in our business, including commodity and interest-rate risks; however, the capital requirements and costs of hedging may increase as a result of the regulations. We also may incur additional costs associated with our compliance with the new regulations and anticipated additional record keeping, reporting and disclosure obligations; however, we do not believe the costs will be material. These requirements could affect adversely market liquidity and pricing of derivative contracts, making it more difficult to execute our risk-management strategies in the future. Also, the anticipated increased costs of compliance by dealers and counterparties likely will be passed on to customers, which could decrease the benefits of hedging to us and could reduce our profitability and liquidity.

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 our Board of Directors.

Derivatives and Risk Management - We utilize derivatives to reduce our market risk exposure to commodity price and interest-rate fluctuations and 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 B and C 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. There were no impairment charges resulting from our 2012, 2011 or 2010 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 exceeds 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 multiples to forecasted cash flows. 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.

Our goodwill impairment analysis performed as of July 1, 2012, 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. The following table sets forth our goodwill, by segment, for the periods indicated:

	December 31, 2012	December 31, 2011
	(Thousands of dollars)	
Natural Gas Gathering and Processing	**$ 92,141**	$ 90,037
Natural Gas Pipelines	**129,011**	131,115
Natural Gas Liquids	**175,566**	175,566
Total goodwill	**$ 396,718**	$ 396,718

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 2012, 2011 or 2010.

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 2012, 2011 or 2010.

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 the Powder River Basin. The reduced development activities and natural production declines in the Powder River Basin have resulted in lower natural gas volumes available to be gathered. While the reserve potential in the Powder River Basin still exists, future drilling and development in this area will be affected by commodity prices and producers' alternative prospects. Bighorn Gas Gathering, in which we own a 49-percent equity interest, operates in the Powder River Basin. Due to declines in volumes gathered on the Bighorn Gas Gathering system, we tested our investment for impairment. The carrying amount of our investment as of December 31, 2012, was $90.4 million, which includes $53.4 million in equity method goodwill. We estimated the fair value of our investment in Bighorn Gas Gathering using an income approach, which discounted the estimated future cash flows of our investment's underlying assets with a discount rate reflective of our cost of capital and estimated contract rates, volumes, operating and maintenance costs and capital expenditures. The fair value exceeded the carrying value; therefore, no impairment was recorded.

A continued decline in volumes in the Powder River Basin may reduce our ability to recover the carrying value of our assets and equity investments in this area and could result in noncash charges to earnings. A 10-percent decline in the fair value of our investment in Bighorn Gas Gathering would result in a noncash impairment charge. For our other equity method investments with operations in the Powder River Basin with carrying values of approximately $200 million, which includes approximately $130 million in equity method goodwill, we did not identify current events or circumstances that warranted an impairment analysis or adjustment to our carrying values. We are not able to reasonably estimate a range of potential future charges, as many of the assumptions that would be used in a fair value model are dependent upon events such as commodity prices, producers' drilling and production activity and effects of government regulations and policies.

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, D and E of the Notes to Consolidated Financial Statements in this Annual Report for additional discussion of goodwill and long-lived assets.

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 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 2012, 2011 or 2010. Actual results may differ from our estimates resulting in an impact, positive or negative, on earnings. See Note M 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, 2012. For additional discussion of the debt and operating lease agreements, see Notes G and M, respectively, of the Notes to Consolidated Financial Statements in this Annual Report.

	Payments Due by Period						
Contractual Obligations	**Total**	**2013**	**2014**	**2015**	**2016**	**2017**	**Thereafter**
				(Millions of dollars)			
ONEOK Partners senior notes	$ 4,750.0	$ —	$ —	$ —	$ 1,100.0	$ 400.0	$ 3,250.0
Guardian Pipeline senior notes	74.9	7.7	7.7	7.7	7.7	7.7	36.4
Interest payments on debt	3,877.2	256.8	254.9	253.6	227.4	202.8	2,681.7
Operating leases	3.6	0.6	1.8	0.4	0.3	0.2	0.3
Firm transportation and storage contracts	106.6	16.3	13.2	13.0	11.7	10.1	42.3
Financial and physical derivatives	79.7	79.7	—	—	—	—	—
Purchase commitments, rights of way and other	597.0	366.8	61.5	26.1	26.1	26.1	90.4
Total	$ 9,489.0	$ 727.9	$ 339.1	$ 300.8	$ 1,373.2	$ 646.9	$ 6,101.1

Long-term debt - Long-term debt as reported on our Consolidated Balance Sheets includes unamortized debt discount.

Interest payments on debt - Interest expense is calculated by taking long-term debt and multiplying it by the respective coupon rates.

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

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

Financial and physical derivatives - These are obligations arising from our fixed- and variable-price purchase commitments for physical and financial commodity derivatives. Estimated future variable-price purchase commitments are based on market information at December 31, 2012. Actual future variable-price purchase obligations may vary depending on market prices at the time of delivery. Sales of the related physical volumes and net positive settlements of financial derivatives are not reflected in the table above.

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

FORWARD-LOOKING STATEMENTS

Some of the statements contained and incorporated in this Annual Report are forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. The forward-looking statements relate to our anticipated financial performance, liquidity, management's plans and objectives for our future operations, 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 the Private Securities Litigation Reform Act of 1995. 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, which are applicable only as of the date of this Annual Report. 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 between 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 and crude oil because of market conditions caused by concerns about global warming;
- 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 OCC, KCC, Texas regulatory authorities or any other 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. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these factors. 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. To a lesser extent, exposures arise from the relative price differential between NGLs and natural gas, or the gross processing spread, with respect to our keep-whole 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 minimize the impact of price fluctuations related to natural gas, NGLs and condensate.

As of December 31, 2012, we had $17.6 million of commodity-related derivative assets and $2.5 million of commodity-related derivative liabilities, excluding the impact of netting. The following tables set forth our Natural Gas Gathering and Processing segment's hedging information for the periods indicated:

	Year Ending December 31, 2013				
	Volumes Hedged	Average Price			Percentage Hedged
NGLs *(Bbl/d)*	6,439	$	1.19	/ gallon	45%
Condensate *(Bbl/d)*	2,038	$	2.43	/ gallon	83%
Total *(Bbl/d)*	8,477	$	1.49	/ gallon	51%
Natural gas *(MMBtu/d)*	60,014	$	3.79	/ MMBtu	79%

	Year Ending December 31, 2014				
	Volumes Hedged	Average Price			Percentage Hedged
Condensate *(Bbl/d)*	868	$	2.22	/ gallon	33%
Natural gas *(MMBtu/d)*	36,726	$	4.11	/ MMBtu	48%

We expect our commodity price risk to increase in the future as volumes increase under POP contracts with our customers. Our Natural Gas Gathering and Processing segment's commodity price risk is estimated as a hypothetical change in the price of NGLs, crude oil and natural gas at December 31, 2012, 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 annual net margin by approximately $2.1 million;
- a $1.00 per barrel change in the price of crude oil would change annual net margin by approximately $1.1 million; and
- a $0.10 per MMBtu change in the price of natural gas would change annual net margin by approximately $2.8 million.

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, 2012, there were no financial derivative instruments with respect to our natural gas pipeline operations.

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, 2012, there were no financial derivative instruments with respect to our NGL operations.

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

INTEREST-RATE RISK

General - We are subject to the risk of interest-rate fluctuation in the normal course of business. We manage interest-rate risk through the use of fixed-rate debt, floating-rate debt and, at times, interest-rate swaps. Fixed-rate swaps may be used to reduce our risk of increased interest costs during periods of rising interest rates. Floating-rate swaps may be used to convert the fixed rates of long-term borrowings into short-term variable rates. At December 31, 2012, the interest rate on all of our long-term debt was fixed, and we had forward-starting interest-rate swaps with notional amounts of $400 million that have been designated as cash flow hedges of the variability of interest payments on a portion of a forecasted debt issuance that may result from changes in the benchmark interest rate before the debt is issued. At December 31, 2012, we had derivative assets of $10.9 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.

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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, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, 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, 2012, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A in the Partnership's Form 10-K for the year ended December 31, 2012. 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 26, 2013

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

	Years Ended December 31,		
	2012	**2011**	**2010**
	(Thousands of dollars, except per unit amounts)		
Revenues	**$ 10,182,151**	$ 11,322,607	$ 8,675,900
Cost of sales and fuel	**8,540,319**	9,745,227	7,531,047
Net margin	**1,641,832**	1,577,380	1,144,853
Operating expenses			
Operations and maintenance	**433,063**	414,488	363,482
Depreciation and amortization	**203,101**	177,549	173,708
General taxes	**49,477**	44,876	39,994
Total operating expenses	**685,641**	636,913	577,184
Gain (loss) on sale of assets	**6,736**	(963)	18,632
Operating income	**962,927**	939,504	586,301
Equity earnings from investments (Note K)	**123,024**	127,246	101,880
Allowance for equity funds used during construction	**13,648**	2,335	1,018
Other income	**7,577**	1,060	6,009
Other expense	**(2,625)**	(3,547)	(2,511)
Interest expense (net of capitalized interest of $40,482, $22,221 and $3,832, respectively)	**(206,018)**	(223,137)	(204,307)
Income before income taxes	**898,533**	843,461	488,390
Income taxes (Note J)	**(10,105)**	(12,569)	(15,082)
Net income	**888,428**	830,892	473,308
Less: Net income attributable to noncontrolling interests	**438**	573	606
Net income attributable to ONEOK Partners, L.P.	**$ 887,990**	$ 830,319	$ 472,702
Limited partners' interest in net income:			
Net income attributable to ONEOK Partners, L.P.	**$ 887,990**	$ 830,319	$ 472,702
General partner's interest in net income	**(227,855)**	(147,820)	(118,165)
Limited partners' interest in net income	**$ 660,135**	$ 682,499	$ 354,537
Limited partners' net income per unit, basic and diluted (Note I)	**$ 3.04**	$ 3.35	$ 1.75
Number of units used in computation (*thousands*)	**217,134**	203,816	202,738

See accompanying Notes to Consolidated Financial Statements.

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

	Years Ended December 31,		
	2012	**2011**	**2010**
	(Thousands of dollars)		
Net income	**$ 888,428**	$ 830,892	$ 473,308
Other comprehensive income (loss)			
Unrealized gains (losses) on derivatives	**10,295**	(59,345)	31,296
Realized (gains) losses on derivatives recognized in net income	**(58,529)**	1,974	(2,976)
Total other comprehensive income (loss)	**(48,234)**	(57,371)	28,320
Comprehensive income	**840,194**	773,521	501,628
Less: Comprehensive income attributable to noncontrolling interests	**438**	573	606
Comprehensive income attributable to ONEOK Partners, L.P.	**$ 839,756**	$ 772,948	$ 501,022

See accompanying Notes to Consolidated Financial Statements.

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

		December 31, 2012		December 31, 2011
Assets		*(Thousands of dollars)*		
Current assets				
Cash and cash equivalents	**$**	**537,074**	$	35,091
Accounts receivable, net		**914,036**		922,237
Affiliate receivables		**16,092**		4,132
Gas and natural gas liquids in storage		**235,836**		202,186
Commodity imbalances		**89,704**		62,884
Other current assets		**98,966**		79,343
Total current assets		**1,891,708**		1,305,873
Property, plant and equipment				
Property, plant and equipment		**8,585,142**		6,963,652
Accumulated depreciation and amortization		**1,440,871**		1,259,697
Net property, plant and equipment (Note D)		**7,144,271**		5,703,955
Investments and other assets				
Investments in unconsolidated affiliates (Note K)		**1,221,405**		1,223,398
Goodwill and intangible assets (Note E)		**645,871**		653,537
Other assets		**55,975**		59,913
Total investments and other assets		**1,923,251**		1,936,848
Total assets	**$**	**10,959,230**	$	8,946,676
Liabilities and equity				
Current liabilities				
Current maturities of long-term debt (Note G)	**$**	**7,650**	$	361,062
Notes payable (Note F)		**—**		—
Accounts payable		**1,058,007**		1,049,284
Affiliate payables		**75,710**		41,096
Commodity imbalances		**273,173**		202,542
Other current liabilities		**155,892**		234,645
Total current liabilities		**1,570,432**		1,888,629
Long-term debt, excluding current maturities (Note G)		**4,803,629**		3,515,566
Deferred credits and other liabilities		**121,662**		95,969
Commitments and contingencies (Note M)				
Equity				
ONEOK Partners, L.P. partners' equity:				
General partner		**152,513**		106,936
Common units: 146,827,354 and 130,827,354 units issued and outstanding at December 31, 2012 and December 31, 2011, respectively		**2,945,051**		1,959,437
Class B units: 72,988,252 units issued and outstanding at December 31, 2012 and December 31, 2011		**1,460,498**		1,426,115
Accumulated other comprehensive loss		**(99,322)**		(51,088)
Total ONEOK Partners, L.P. partners' equity		**4,458,740**		3,441,400
Noncontrolling interests in consolidated subsidiaries		**4,767**		5,112
Total equity		**4,463,507**		3,446,512
Total liabilities and equity	**$**	**10,959,230**	$	8,946,676

See accompanying Notes to Consolidated Financial Statements.

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

	Years Ended December 31,		
	2012	**2011**	**2010**
	(Thousands of dollars)		
Operating activities			
Net income	**$ 888,428**	$ 830,892	$ 473,308
Depreciation and amortization	**203,101**	177,549	173,708
Allowance for equity funds used during construction	**(13,648)**	(2,335)	(1,018)
Loss (gain) on sale of assets	**(6,736)**	963	(18,632)
Deferred income taxes	**6,815**	4,417	10,824
Equity earnings from investments	**(123,024)**	(127,246)	(101,880)
Distributions received from unconsolidated affiliates	**120,442**	132,741	96,958
Changes in assets and liabilities:			
Accounts receivable	**8,201**	(107,096)	(196,293)
Affiliate receivables	**(11,960)**	1,029	27,236
Gas and natural gas liquids in storage	**(33,650)**	114,973	(100,167)
Accounts payable	**(45,014)**	161,323	138,900
Affiliate payables	**34,614**	11,331	7,899
Commodity imbalances, net	**43,811**	(59,099)	(5,754)
Other assets and liabilities	**(125,327)**	(9,707)	(9,885)
Cash provided by operating activities	**946,053**	1,129,735	495,204
Investing activities			
Capital expenditures (less allowance for equity funds used during construction)	**(1,560,513)**	(1,063,383)	(352,714)
Contributions to unconsolidated affiliates	**(30,768)**	(64,491)	(1,331)
Distributions received from unconsolidated affiliates	**35,299**	23,644	17,847
Proceeds from sale of assets	**10,778**	1,093	428,485
Cash provided by (used in) investing activities	**(1,545,204)**	(1,103,137)	92,287
Financing activities			
Cash distributions:			
General and limited partners	**(760,912)**	(609,446)	(563,184)
Noncontrolling interests	**(783)**	(637)	(1,005)
Repayment of notes payable, net	**—**	(429,855)	(93,145)
Issuance of long-term debt, net of discounts	**1,295,036**	1,295,450	—
Long-term debt financing costs	**(9,641)**	(10,986)	—
Repayment of long-term debt	**(361,062)**	(236,931)	(261,931)
Issuance of common units, net of issuance costs	**919,427**	—	322,701
Contribution from general partner	**19,069**	—	6,820
Cash provided by (used in) financing activities	**1,101,134**	7,595	(589,744)
Change in cash and cash equivalents	**501,983**	34,193	(2,253)
Cash and cash equivalents at beginning of period	**35,091**	898	3,151
Cash and cash equivalents at end of period	**$ 537,074**	$ 35,091	$ 898
Supplemental cash flow information:			
Cash paid for interest, net of amounts capitalized	**$ 317,044**	$ 198,579	$ 206,706
Cash paid for income taxes	**$ 7,542**	$ 2,252	$ 7,215

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, 2010	119,825,554	72,988,252	$ 84,434	$ 1,561,762
Net income	—	—	118,165	226,752
Other comprehensive income	—	—	—	—
Issuance of common units (Note H)	11,001,800	—	—	322,701
Contribution from general partner (Note H)	—	—	6,820	—
Distributions paid (Note H)	—	—	(114,728)	(285,694)
Other	—	—	—	—
December 31, 2010	130,827,354	72,988,252	94,691	1,825,521
Net income	—	—	147,820	438,089
Other comprehensive loss	—	—	—	—
Distributions paid (Note H)	—	—	(135,575)	(304,173)
Other	—	—	—	—
December 31, 2011	130,827,354	72,988,252	106,936	1,959,437
Net income	**—**	**—**	**227,855**	**436,710**
Other comprehensive loss	**—**	**—**	**—**	**—**
Issuance of common units (Note H)	**16,000,000**	**—**	**—**	**919,427**
Contribution from general partner (Note H)	**—**	**—**	**19,069**	**—**
Distributions paid (Note H)	**—**	**—**	**(201,347)**	**(370,523)**
December 31, 2012	**146,827,354**	**72,988,252**	**$ 152,513**	**$ 2,945,051**

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, 2010	$ 1,380,299	$ (22,037)	$ 5,603	$ 3,010,061
Net income	127,785	—	606	473,308
Other comprehensive income	—	28,320	—	28,320
Issuance of common units (Note H)	—	—	—	322,701
Contribution from general partner (Note H)	—	—	—	6,820
Distributions paid (Note H)	(162,762)	—	(1,005)	(564,189)
Other	—	—	(28)	(28)
December 31, 2010	1,345,322	6,283	5,176	3,276,993
Net income	244,410	—	573	830,892
Other comprehensive loss	—	(57,371)	—	(57,371)
Distributions paid (Note H)	(169,698)	—	(637)	(610,083)
Other	6,081	—	—	6,081
December 31, 2011	1,426,115	(51,088)	5,112	3,446,512
Net income	**223,425**	**—**	**438**	**888,428**
Other comprehensive loss	**—**	**(48,234)**	**—**	**(48,234)**
Issuance of common units (Note H)	**—**	**—**	**—**	**919,427**
Contribution from general partner (Note H)	**—**	**—**	**—**	**19,069**
Distributions paid (Note H)	**(189,042)**	**—**	**(783)**	**(761,695)**
December 31, 2012	**$ 1,460,498**	**$ (99,322)**	**$ 4,767**	**$ 4,463,507**

ONEOK PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Nature of Operations - ONEOK Partners, L.P. is a publicly traded master limited partnership, organized under the laws of the state of Delaware, that was formed in 1993. Our equity consists of a 2-percent general partner interest and a 98-percent limited partner interest. Our limited partner interests are represented by our common units, which are listed on the NYSE under the trading symbol "OKS," and our Class B limited partner units. We are managed under the direction of the Board of Directors of our sole general partner, ONEOK Partners GP. ONEOK Partners GP is a wholly owned subsidiary of ONEOK. ONEOK and its subsidiaries own a 43.4-percent aggregate equity interest in us.

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 and Granite Wash formations, 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. The natural gas we gather in 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 market for a fee.

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 have access to the major natural gas producing areas including the Cana-Woodford Shale, Granite Wash and Mississippian Lime areas, and transport natural gas throughout the state. We also have access to the major natural gas producing area 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 area, and the Permian Basin and transport natural gas throughout the western portion of the state, 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, Kansas and Texas, which are connected to our intrastate natural gas pipeline assets.

Our natural gas liquids assets consist of facilities that gather, fractionate and treat NGLs and store NGL products primarily in Oklahoma, Kansas and Texas. We own or have an ownership interest in FERC-regulated natural gas liquids gathering and distribution pipelines in Oklahoma, Kansas, Texas, Wyoming, Colorado, North Dakota and Montana 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 fractionation and pipeline assets.

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 K 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 and liabilities, 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 the income approach to determine the fair value of our derivative assets and liabilities and consider the markets in which the transactions are executed. We measure the fair value of a group of financial assets and liabilities consistent with how a market participant would price the net risk exposure at the measurement date.

While many of the contracts in our portfolio are executed in liquid markets where price transparency exists, some contracts are executed in markets for which market prices may exist, but the market may be relatively inactive. This results in limited price transparency that requires management's judgment and assumptions to estimate fair values. For certain transactions, we utilize modeling techniques using NYMEX-settled pricing data, historical correlations of NGL product prices to crude oil prices and implied forward LIBOR curves. 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. Finally, we consider the credit risk of our counterparties with whom our derivative assets and liabilities are executed. 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 significant.

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 - Unadjusted quoted prices in active markets for identical assets or liabilities;
- Level 2 - Significant observable pricing inputs other than quoted prices included within Level 1 that are either directly or indirectly observable as of the reporting date. Essentially, this represents inputs that are derived principally from or corroborated by observable market data;
- Level 3 - May include one or more unobservable inputs that are significant in establishing a fair value estimate. These unobservable inputs are developed based on the best information available and may include our own internal data.

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 B 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 operating 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 Pipelines segment and Natural Gas Liquids segment are recognized based upon contracted capacity and contracted volumes transported and stored under service agreements in the period services are provided.

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 regularly reviewed 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, 2012 and 2011, 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 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, options or swap transactions in order to hedge anticipated purchases and sales of natural gas, NGLs and condensate and fuel requirements. Interest-rate swaps are used from time to time to manage interest-rate risk. Under certain conditions, we designate these derivative instruments as a hedge of exposure to changes in fair values or cash flow. We formally document all relationships between hedging instruments and hedged items, as well as risk-management objectives and strategies for undertaking various hedge transactions and methods for assessing and testing correlation and hedge ineffectiveness. We specifically identify the forecasted transaction that has been designated as the hedged item with a cash flow hedge. 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 Consolidated Statement of Cash Flows category as the cash flows from the related hedged items.

See Notes B and C 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 D 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. There were no impairment charges resulting from our 2012, 2011 or 2010 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 exceeds 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 multiples to forecasted cash flows. 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.

Our goodwill impairment analysis performed as of July 1, 2012, 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.

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 2012, 2011 or 2010.

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 2012, 2011 or 2010.

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 the Powder River Basin. The reduced development activities and natural production declines in the Powder River Basin have resulted in lower natural gas volumes available to be gathered. While the reserve potential in the Powder River Basin still exists, future drilling and development in this area will be affected by commodity prices and producers' alternative prospects. Bighorn Gas Gathering, in which we own a 49-percent equity interest, has operations in the Powder River Basin. Due to declines in volumes gathered on the Bighorn Gas Gathering system, we tested our investment for impairment. The carrying amount of our investment as of December 31, 2012, was $90.4 million, which includes $53.4 million in equity method goodwill. We estimated the fair value of our investment in Bighorn Gas Gathering using an income approach, which discounted the estimate future cash flows of our investment's underlying assets with a discount rate reflective of our cost of capital and estimated contract rates, volumes, operating and maintenance costs and capital expenditures. The fair value exceeded the carrying value; therefore, no impairment was recorded.

A continued decline in volumes in the Powder River Basin may reduce our ability to recover the carrying value of our assets and equity investments in this area and could result in noncash charges to earnings. A 10-percent decline in the fair value of our investment in Bighorn Gas Gathering would result in a noncash impairment charge. For our other equity method investments with operations in the Powder River Basin with carrying values of approximately $200 million, which includes approximately $130 million in equity method goodwill, we did not identify current events or circumstances that warranted an impairment analysis or adjustment to our carrying values. We are not able to reasonably estimate a range of potential future charges, as many of the assumptions that would be used in a fair value model are dependent upon events such as commodity prices, producers' drilling and production activity and effects of government regulations and policies.

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 D and E for our goodwill and long-lived assets disclosures.

Regulation - Our intrastate natural gas transmission pipelines are subject to the rate regulation and accounting requirements of the OCC, KCC and RRC. 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 Pipelines and Natural Gas Liquids segments follow the accounting and reporting guidance for regulated operations. During the rate-making process, 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, 2012 and 2011, we recorded regulatory assets of approximately $7.9 million and $9.3 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 carry-forward 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 2012, 2011 and 2010, 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 J 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. 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 reasonably estimate the fair value of the asset retirement obligations for portions of our assets because the settlement dates are indeterminable. 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 are nonlegal obligations; however, the amounts collected in excess of the nonlegal asset removal costs incurred are accounted for as a regulatory liability. 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, significant uncertainty exists regarding the ultimate determination of this 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. Actual results may differ from our estimates resulting in an impact, positive or negative, on earnings. See Note M for additional discussion of contingencies.

Recently Issued Accounting Standards Update - In May 2011, the FASB issued ASU 2011-04, "Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and International Financial Reporting Standards (IFRS)," which provides a consistent definition of fair value and common requirements for measurement of and disclosure about fair value between GAAP and IFRS. This new guidance changes some fair value measurement principles and disclosure requirements. We adopted this guidance with our March 31, 2012, Quarterly Report, and the impact was not material.

In June 2011, the FASB issued ASU 2011-05, "Presentation of Comprehensive Income," which provides two options for presenting items of net income, other comprehensive income and total comprehensive income, by either creating one continuous statement of comprehensive income or two separate consecutive statements and requires certain other disclosures. In December 2011, the FASB issued ASU 2011-12, "Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05," which deferred certain presentation requirements in ASU 2011-05 for items reclassified out of accumulated other comprehensive income. We adopted this guidance except for the portions deferred by ASU 2011-12, with our March 31, 2012, Quarterly Report, and the impact was not material.

In February 2013, the FASB issued ASU 2013-02, "Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income," which requires presentation in a single location, either in a single note or parenthetically on the face of the financial statements, the effect of significant amounts reclassified from each component of accumulated other comprehensive income based on its source. We will adopt this guidance with our March 31, 2013, Quarterly Report.

In September 2011, the FASB issued ASU 2011-08, "Testing Goodwill for Impairment," which permits an entity to first assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount. Under the amendments in this update, an entity is not required to calculate the fair value of a reporting unit unless the entity determines that it is more likely than not that its fair value is less than its carrying amount. An entity has the option to bypass the qualitative assessment for any reporting unit in any period and proceed directly to performing the first step of the two-step goodwill impairment test. An entity may also resume performing the qualitative assessment in any subsequent period. We adopted this guidance beginning with our July 1, 2012, goodwill impairment test, and it did not impact our financial position or results of operations.

In December 2011, the FASB issued ASU No. 2011-11, "Disclosures about Offsetting Assets and Liabilities," which increases disclosures about offsetting assets and liabilities. In January 2013, the FASB issued ASU 2013-01, "Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities," which clarifies that the scope of ASU 2011-01 applies to derivatives accounted for in accordance with Topic 815, Derivatives and Hedging. New disclosures are required to enable users of financial statements to understand significant quantitative differences in balance sheets prepared under GAAP and IFRS related to the offsetting of financial instruments, including derivatives. The existing GAAP guidance allowing balance sheet offsetting remains unchanged. This guidance will be effective for interim and annual periods beginning on January 1, 2013, and will be applied retrospectively for all comparative periods presented. The adoption of this guidance beginning with our March 31, 2013, Quarterly Report will not affect our financial condition, results of operations or cash flows.

B. FAIR VALUE MEASUREMENTS

Recurring Fair Value Measurements - The following tables set forth our recurring fair value measurements for the periods indicated:

	December 31, 2012					
	Level 1	**Level 2**	**Level 3**	**Total - Gross**	**Netting (a)**	**Total - Net (b)**
			(Thousands of dollars)			
Derivatives - commodity						
Assets	**$ —**	**$ 17,581**	**$ 1**	**$ 17,582**	**$ (2,455)**	**$ 15,127**
Liabilities	**$ —**	**$ (31)**	**$ (2,424)**	**$ (2,455)**	**$ 2,455**	**$ —**
Derivatives - interest rate						
Assets	**$ —**	**$ 10,923**	**$ —**	**$ 10,923**	**$ —**	**$ 10,923**

	December 31, 2011					
	Level 1	**Level 2**	**Level 3**	**Total - Gross**	**Netting (a)**	**Total - Net (b)**
			(Thousands of dollars)			
Derivatives - commodity						
Assets	$ —	$ 27,608	$ 6,119	$ 33,727	$ (3,839)	$ 29,888
Liabilities	$ —	$ (837)	$ (3,002)	$ (3,839)	$ 3,839	$ —
Derivatives - interest rate						
Liabilities	$ —	$ (77,509)	$ —	$ (77,509)	$ —	$ (77,509)

(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.
(b) - Included in other current assets, other assets or other current liabilities in our Consolidated Balance Sheets.

At December 31, 2012 and 2011, we had no cash collateral held or posted under our master netting arrangements.

Our Level 1 fair value would include amounts based on unadjusted quoted prices in active markets including NYMEX-settled prices. These balances would be comprised predominantly of NYMEX-traded derivative contracts for natural gas and crude oil.

Our Level 2 fair value amounts 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.

Our Level 3 fair value amounts 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 natural gas liquids.

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, 2012**	**2011**
	(Thousands of dollars)	
Net assets (liabilities) at beginning of period	**$ 3,117**	$ 1,156
Total realized/unrealized gains (losses):		
Included in earnings (a)	**—**	(885)
Included in other comprehensive income (loss)	**(5,540)**	2,846
Net assets (liabilities) at end of period	**$ (2,423)**	$ 3,117
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)	**$ —**	$ —

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

During the year ended December 31, 2012, 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. The estimated fair value of the aggregate of our senior notes outstanding, including current maturities, was $5.6 billion and $4.5 billion at December 31, 2012 and 2011, respectively. The book value of the aggregate of our senior notes outstanding, including current maturities, was $4.8 billion and $3.9 billion at December 31, 2012 and 2011, respectively. The estimated fair value of the aggregate of our senior notes outstanding was determined using quoted market prices for similar issues with similar terms and maturities. Our long-term debt is classified as Level 2.

C. 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 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 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. This transfers 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.

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. To a lesser extent, exposures arise from the relative price differential between NGLs and natural gas, or the gross processing spread, with respect to our keep-whole 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 minimize the impact of price fluctuations related to natural gas, NGLs and condensate.

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, 2012 and 2011, there were no financial derivative instruments with respect to our natural gas pipeline operations.

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, 2012 and 2011, there were no financial derivative instruments with respect to our NGL 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.

We have entered into forward-starting interest-rate swaps 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, 2011, we had interest-rate swaps with notional values totaling $750 million. During the year ended December 31, 2012, we entered into additional interest-rate swaps with notional amounts totaling $650 million. Upon our debt issuance in September 2012, we settled $1 billion of our interest-rate swaps and realized a loss of $124.9 million in accumulated other comprehensive income (loss) that will be amortized to interest expense over the term of the related debt. At December 31, 2012, our remaining interest-rate swaps with notional amounts totaling $400 million have settlement dates greater than 12 months.

Fair Values of Derivative Instruments - See Note B for a discussion of the inputs associated with our fair value measurements. The following table sets forth the fair values of our derivative instruments, all of which were designated as cash flow hedges, for the periods indicated:

	December 31, 2012		December 31, 2011	
	Assets (a)	**(Liabilities) (a)**	**Assets (b)**	**(Liabilities) (b)**
	(Thousands of dollars)			
Commodity contracts - financial	**$ 17,582**	**$ (2,455)**	$ 33,727	$ (3,839)
Interest-rate contracts	**10,923**	**—**	—	(77,509)
Total derivatives designated as hedging instruments	**$ 28,505**	**$ (2,455)**	$ 33,727	$ (81,348)

(a) - Included on a net basis in other current assets and other assets on our Consolidated Balance Sheets.
(b) - Included on a net basis in other current assets, other assets and 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:

		December 31, 2012		December 31, 2011	
	Contract Type	**Purchased/ Payor**	**Sold/ Receiver**	**Purchased/ Payor**	**Sold/ Receiver**
Cash flow hedges					
Fixed price					
-Natural gas (*Bcf*)	Swaps	**—**	**(31.7)**	—	(21.5)
-Crude oil and NGLs (*MMBbl*)	Swaps	**—**	**(1.1)**	—	(2.9)
Basis					
-Natural gas (*Bcf*)	Swaps	**—**	**(31.7)**	—	(21.5)
Interest-rate contracts (*Millions of dollars*)	Forward-starting swaps	**$ 400.0**	**$ —**	$ 750.0	$ —

Cash Flow Hedges - At December 31, 2012, our Consolidated Balance Sheet reflected a net unrealized loss of $99.3 million in accumulated other comprehensive income (loss). The portion of accumulated other comprehensive income (loss) attributable to our commodity derivative financial instruments is a gain of $15.1 million, which will be realized within the next 24 months as the forecasted transactions affect earnings. If commodity prices remain at the current levels, we will recognize $13.3 million in gains over the next 12 months, and we will recognize $1.8 million in gains thereafter. The remaining amounts deferred in accumulated other comprehensive income (loss) are primarily attributable to our interest-rate swaps, of which we expect that losses of $10.1 million will be reclassified into earnings during the next 12 months as the hedged items affect earnings. Amounts in accumulated other comprehensive income (loss) attributable to forward-starting interest-rate swaps with settlement dates greater than 12 months 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 effect of cash flow hedges recognized in other comprehensive income (loss) for the periods indicated:

	Years Ended December 31,		
Derivatives in Cash Flow Hedging Relationships	**2012**	**2011**	**2010**
	(Thousands of dollars)		
Commodity contracts	**$ 46,804**	$ 18,164	$ 31,296
Interest-rate contracts	**(36,509)**	(77,509)	—
Total gain (loss) recognized in other comprehensive income (loss) (effective portion)	**$ 10,295**	$ (59,345)	$ 31,296

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 Income (Loss) into Net Income (Effective Portion)	Years Ended December 31, 2012	2011	2010
		(Thousands of dollars)		
Commodity contracts	Revenues	**$ 61,526**	$ (1,494)	$ 2,949
Interest-rate contracts	Interest expense	**(2,997)**	(480)	27
Total gain (loss) reclassified from accumulated other comprehensive income (loss) into net income (effective portion)		**$ 58,529**	$ (1,974)	$ 2,976

Ineffectiveness related to our cash flow hedges was not material for the years ended December 31, 2012, 2011 and 2010. 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 2012, 2011 and 2010.

Credit Risk - All of our commodity derivative financial contracts are with our affiliate, ONEOK Energy Services Company, L.P. (OES), a subsidiary of ONEOK. OES has entered into similar commodity derivative financial contracts with third parties at our direction and on our behalf. We have an indemnification agreement with OES that indemnifies and holds OES harmless from any liability it may incur solely as a result of its entering into commodity derivative financial contracts on our behalf. Derivative assets for which we would indemnify OES in the event of a default by the counterparty totaled $15.1 million and $29.9 million at December 31, 2012 and 2011, respectively, and were with investment-grade counterparties that are primarily in the oil and gas and financial services sectors. Our interest-rate derivatives are with investment-grade financial institutions.

D. 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, 2012	December 31, 2011
		(Thousands of dollars)	
Non-Regulated			
Gathering pipelines and related equipment	5 to 40	**$ 1,638,037**	$ 1,350,227
Processing and fractionation and related equipment	5 to 40	**1,625,146**	1,294,586
Storage and related equipment	5 to 54	**335,237**	299,610
Transmission pipelines and related equipment	22 to 54	**311,038**	182,863
General plant and other	2 to 42	**76,903**	67,006
Construction work in process	—	**860,265**	687,294
Regulated			
Storage and related equipment	5 to 54	**136,938**	136,971
Natural gas transmission pipelines and related equipment	5 to 77	**1,394,653**	1,404,288
Natural gas liquids transmission pipelines and related equipment	5 to 80	**1,490,511**	1,436,500
General plant and other	2 to 53	**53,552**	52,857
Construction work in process	—	**662,862**	51,450
Property, plant and equipment		**8,585,142**	6,963,652
Accumulated depreciation and amortization - non-regulated		**(864,287)**	(740,648)
Accumulated depreciation and amortization - regulated		**(576,584)**	(519,049)
Net property, plant and equipment		**$ 7,144,271**	$ 5,703,955

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, 2012	2011	2010
Natural Gas Pipelines	**2.2%**	2.2%	2.2%
Natural Gas Liquids	**1.9%**	1.9%	1.9%

We incurred liabilities for construction work in process that had not been paid at December 31, 2012, 2011 and 2010 of $216.5 million, $152.0 million and $56.2 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.

E. GOODWILL AND INTANGIBLE ASSETS

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

	December 31, 2012	December 31, 2011
	(Thousands of dollars)	
Natural Gas Gathering and Processing	**$ 92,141**	$ 90,037
Natural Gas Pipelines	**129,011**	131,115
Natural Gas Liquids	**175,566**	175,566
Total goodwill	**$ 396,718**	$ 396,718

Intangible Assets - Our intangible assets relate primarily to contracts acquired through acquisitions in our Natural Gas Liquids segment, which are being amortized over an aggregate weighted-average period of 40 years. Amortization expense for intangible assets for 2012, 2011 and 2010 was $7.7 million each year, and the aggregate amortization expense for each of the next five years is estimated to be approximately $7.7 million. The following table reflects the gross carrying amount and accumulated amortization of intangible assets for the periods presented:

	December 31, 2012	December 31, 2011
	(Thousands of dollars)	
Gross intangible assets	**$ 306,650**	$ 306,650
Accumulated amortization	**(57,497)**	(49,831)
Net intangible assets	**$ 249,153**	$ 256,819

F. CREDIT FACILITIES AND SHORT-TERM NOTES PAYABLE

Partnership Credit Agreement - Our Partnership Credit Agreement contains certain financial, operational and legal covenants. Among other things, these covenants include maintaining a ratio of indebtedness to adjusted EBITDA (EBITDA, as defined in our Partnership Credit Agreement, adjusted for all noncash charges and increased for projected EBITDA from certain lender-approved capital expansion projects) of no more than 5.0 to 1.

If we consummate one or more acquisitions in which the aggregate purchase price is $25 million or more, the allowable ratio of indebtedness to adjusted EBITDA will increase to 5.5 to 1 for the quarter of the acquisition and the two following quarters. Upon breach of certain covenants by us in our Partnership Credit Agreement, amounts outstanding under our Partnership Credit Agreement, if any, may become due and payable immediately. At December 31, 2012, our ratio of indebtedness to adjusted EBITDA was 3.0 to 1, and we were in compliance with all covenants under our Partnership Credit Agreement.

Our Partnership Credit Agreement includes a $100 million sublimit for the issuance of standby letters of credit and also features an option that allows us to request an increase in the size of the facility to an aggregate of $1.7 billion from $1.2 billion by either commitments from new lenders or increased commitments from existing lenders.

Our Partnership Credit Agreement is available for general partnership purposes, including repayment of our commercial paper notes, if necessary. Amounts outstanding under our commercial paper program reduce the borrowing capacity under our Partnership Credit Agreement. The 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. Borrowings, if any, will accrue at LIBOR plus 130 basis points, and the annual facility fee is 20 basis points based on our current credit rating. Our Partnership Credit Agreement is guaranteed fully and unconditionally by the Intermediate Partnership. Borrowings under our Partnership Credit Agreement are nonrecourse to our general partner, and our general partner does not guarantee our debt, commercial paper or other similar commitments.

In October 2011, we increased the size of our commercial paper program to $1.2 billion from $1.0 billion. At December 31, 2012 and 2011, we had no commercial paper outstanding, no letters of credit issued and no borrowings under our Partnership Credit Agreement.

Effective August 1, 2012, we extended the maturity date of our Partnership Credit Agreement from August 1, 2016, to August 1, 2017, pursuant to an extension agreement between us and the lenders.

G. 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, 2012	December 31, 2011
	(Thousands of dollars)	
ONEOK Partners		
$350,000 at 5.90% due 2012	**$ —**	$ 350,000
$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**	—
$500,000 at 8.625% due 2019	**500,000**	500,000
$900,000 at 3.375 % due 2022	**900,000**	—
$600,000 at 6.65% due 2036	**600,000**	600,000
$600,000 at 6.85% due 2037	**600,000**	600,000
$650,000 at 6.125% due 2041	**650,000**	650,000
Guardian Pipeline		
Average 7.85%, due 2022	**74,857**	85,919
Total long-term notes payable	**4,824,857**	3,885,919
Unamortized debt discount and other	**(13,578)**	(9,291)
Current maturities	**(7,650)**	(361,062)
Long-term debt	**$ 4,803,629**	$ 3,515,566

The aggregate maturities of long-term debt outstanding for years 2013 through 2017 are shown below:

	ONEOK Partners	Guardian Pipeline	Total
		(Millions of dollars)	
2013	$ —	$ 7.7	$ 7.7
2014	$ —	$ 7.7	$ 7.7
2015	$ —	$ 7.7	$ 7.7
2016	$ 1,100.0	$ 7.7	$ 1,107.7
2017	$ 400.0	$ 7.7	$ 407.7

<u>Debt issuance and maturity</u> - In September 2012, we completed an underwritten public offering 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 $1.3 billion was used to repay amounts outstanding under our commercial paper program, and the balance will be 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.

In January 2011, we completed an underwritten public offering of senior notes, consisting of $650 million of 3.25-percent senior notes due 2016 and $650 million of 6.125-percent senior notes due 2041. The net proceeds from the offering were approximately $1.3 billion and were used to repay amounts outstanding under our commercial paper program, to repay the $225 million principal amount of senior notes due March 2011 and for general partnership purposes, including capital expenditures.

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. 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 P 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, 2012, 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.

H. 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 43.4-percent ownership interest in us at December 31, 2012.

We entered into an EDA for the offer and sale from time to time of our common units up to an aggregate amount of $300 million. The EDA allows us to offer and sell our common units at prices we deem appropriate through a sales agent. Sales of common units, if any, will be 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 EDA. We intend to use the net proceeds from sales under the program 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 contributed approximately $19 million in order to maintain its 2-percent general partner interest in us. The net proceeds from the issuances were used 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 April 2012 and for other general partnership purposes, including capital expenditures. As a result of these transactions, ONEOK's aggregate ownership interest increased to 43.4 percent from 42.8 percent.

In July 2011, a two-for-one split of our common and Class B units was completed, and our Partnership Agreement was amended to adjust the formula for distributing available cash among our general partner and limited partners to reflect the unit split.

In February 2010, we completed an underwritten public offering of 11,001,800 common units, including the partial exercise by the underwriters of their over-allotment option, at a public offering price of $30.38 per common unit, generating net proceeds of approximately $322.7 million. In conjunction with the offering, ONEOK Partners GP contributed $6.8 million in order to maintain its 2-percent general partner interest in us. We used the proceeds from the sale of common units and the general partner contribution to repay borrowings under our credit agreement and for general partnership purposes.

Partnership Agreement - Available cash, as defined in our Partnership Agreement generally will be distributed to our general partner and limited partners according to their partnership percentages of 2 percent and 98 percent, respectively. Our general partner’s percentage interest in quarterly distributions is increased after certain specified target levels are met during the quarter. On July 12, 2011, the Partnership Agreement was amended to adjust the formula for distributing available cash among our general partner and limited partners to reflect the two-for-one unit split described above. 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, 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
September 30, 2011	$	0.595	October 26, 2011	November 14, 2011
June 30, 2011	$	0.585	July 21, 2011	August 12, 2011
March 31, 2011	$	0.575	April 20, 2011	May 13, 2011
December 31, 2010	$	0.570	January 20, 2011	February 14, 2011
September 30, 2010	$	0.565	October 20, 2010	November 12, 2010
June 30, 2010	$	0.560	July 14, 2010	August 13, 2010
March 31, 2010	$	0.555	April 20, 2010	May 14, 2010
December 31, 2009	$	0.550	January 20, 2010	February 12, 2010

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

	Years Ended December 31,					
	2012		2011		2010	
	(Thousands, except per unit amounts)					
Distribution per unit	**$**	**2.590**	$	2.325	$	2.230
General partner distributions	**$**	**15,217**	$	12,189	$	11,265
Incentive distributions		**186,130**		123,386		103,463
Distributions to general partner		**201,347**		135,575		114,728
Limited partner distributions to ONEOK		**235,442**		197,132		189,076
Limited partner distributions to other unitholders		**324,123**		276,739		259,380
Total distributions paid	**$**	**760,912**	$	609,446	$	563,184

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,		
	2012	2011	2010
	(Thousands, except per unit amounts)		
Distribution per unit	**$ 2.690**	$ 2.365	$ 2.250
General partner distributions	**$ 16,355**	$ 12,515	$ 11,577
Incentive distributions	**210,095**	131,212	108,711
Distributions to general partner	**226,450**	143,727	120,288
Limited partner distributions to ONEOK	**249,600**	200,524	190,774
Limited partner distributions to other unitholders	**341,704**	281,500	267,812
Total distributions declared	**$ 817,754**	$ 625,751	$ 578,874

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.

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.

I. 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 $210.1 million, $131.2 million and $108.7 million for 2012, 2011 and 2010, 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 or distributions in excess of earnings. For additional information regarding our general partner's incentive distribution rights, see "Partnership Agreement" in Note H.

J. INCOME TAXES

The following table sets forth our provision for income taxes for the periods indicated:

	Years Ended December 31,		
	2012	**2011**	**2010**
		(Thousands of dollars)	
Current income tax provision			
Federal	**$ (156)**	$ 2,177	$ 539
State	**3,446**	5,975	3,719
Total current income tax provision	**3,290**	8,152	4,258
Deferred income tax provision			
Federal	**6,330**	3,831	10,125
State	**485**	586	699
Total deferred income tax provision	**6,815**	4,417	10,824
Total provision for income taxes	**$ 10,105**	$ 12,569	$ 15,082

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

	Years Ended December 31,		
	2012	**2011**	**2010**
		(Thousands of dollars)	
Income before income taxes	**$ 898,533**	$ 843,461	$ 488,390
Less: Net income attributable to noncontrolling interests	**438**	573	606
Income attributable to ONEOK Partners, L.P. before income taxes	**898,095**	842,888	487,784
Federal statutory income tax rate	**35.0%**	35.0%	35.0%
Provision for federal income taxes	**314,333**	295,011	170,724
Partnership earnings not subject to tax	**(307,839)**	(288,641)	(160,219)
State income taxes, net of federal benefit	**4,530**	6,239	4,398
Other, net	**(919)**	(40)	179
Income tax provision	**$ 10,105**	$ 12,569	$ 15,082

The following table sets forth the tax effects of temporary differences that gave rise to significant portions of the deferred tax assets and liabilities for the periods indicated:

	Years Ended December 31,	
	2012	**2011**
	(Thousands of dollars)	
Deferred tax assets		
Other	$ 1,302	$ 1,267
Total deferred tax assets	**1,302**	1,267
Deferred tax liabilities		
Excess of tax over book depreciation	**40,666**	33,938
Regulatory assets	**2,772**	2,896
Total deferred tax liabilities	**43,438**	36,834
Net deferred tax liabilities	**$ 42,136**	$ 35,567

Income taxes payable at December 31, 2012 and 2011, were not material.

K. 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, 2012	December 31, 2011
		(Thousands of dollars)	
Northern Border Pipeline	50%	**$ 393,317**	$ 416,206
Overland Pass Pipeline Company	50%	**468,710**	447,449
Fort Union Gas Gathering	37%	**120,782**	117,353
Bighorn Gas Gathering	49%	**90,428**	91,748
Other	Various	**148,168**	150,642
Investments in unconsolidated affiliates (a)		**$ 1,221,405**	$ 1,223,398

(a) - Equity method goodwill (Note A) was $224.3 million at December 31, 2012 and 2011.

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

	Years Ended December 31, 2012	2011	2010
		(Thousands of dollars)	
Northern Border Pipeline	**$ 72,705**	$ 76,365	$ 68,124
Overland Pass Pipeline Company (a)	**20,043**	19,535	5,421
Fort Union Gas Gathering	**17,218**	15,280	14,367
Bighorn Gas Gathering	**3,820**	5,990	5,495
Other	**9,238**	10,076	8,473
Equity earnings from investments	**$ 123,024**	$ 127,246	$ 101,880

(a) - Beginning in September 2010, following the sale of a 49-percent interest, Overland Pass Pipeline Company was deconsolidated and prospectively accounted for under the equity method.

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

	December 31, 2012	December 31, 2011
	(Thousands of dollars)	
Balance Sheet		
Current assets	**$ 175,930**	$ 133,579
Property, plant and equipment, net	**$ 2,593,122**	$ 2,451,798
Other noncurrent assets	**$ 35,005**	$ 35,548
Current liabilities	**$ 145,147**	$ 76,355
Long-term debt	**$ 472,630**	$ 534,485
Other noncurrent liabilities	**$ 42,451**	$ 15,510
Accumulated other comprehensive loss	**$ (2,503)**	$ (2,700)
Owners' equity	**$ 2,146,332**	$ 1,997,275

	Years Ended December 31, 2012	2011	2010
		(Thousands of dollars)	
Income Statement (a)			
Operating revenues	**$ 573,197**	$ 496,158	$ 440,826
Operating expenses	**$ 269,858**	$ 221,261	$ 189,437
Net income	**$ 279,766**	$ 249,559	$ 223,715
Distributions paid to us (a)	**$ 155,741**	$ 156,385	$ 114,805

(a) - Financial information for 2012 and 2011 is not directly comparable with 2010 due to the deconsolidation of Overland Pass Pipeline Company in September 2010.

We incurred expenses in transactions with unconsolidated affiliates of $36.1 million, $31.0 million, and $11.8 million for 2012, 2011, and 2010, respectively, primarily related to Overland Pass Pipeline Company. Accounts payable to our equity method investees at December 31, 2012 and 2011, were not material.

Overland Pass Pipeline Company - In September 2010, we completed a transaction to sell a 49-percent ownership interest in Overland Pass Pipeline Company to a subsidiary of Williams Partners resulting in each joint-venture member now owning 50 percent of Overland Pass Pipeline Company. In accordance with the joint-venture agreement, we received approximately $423.7 million in cash at closing. As a result of the transaction, we no longer control or operate Overland Pass Pipeline Company and began accounting for our investment under the equity method of accounting in September 2010. In connection with the deconsolidation of Overland Pass Pipeline Company, we recognized approximately $16.3 million in gain on sale of assets, primarily attributable to the remeasurement of our retained investment in Overland Pass Pipeline Company to its fair value, and recorded our retained investment of approximately $438.0 million in investments in unconsolidated affiliates. Our estimate of the fair value of our retained interest in Overland Pass Pipeline Company was based upon the income and market valuation approaches.

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. The Northern Border Pipeline Management Committee has adopted a cash distribution policy related to financial ratio targets and capital contributions. The cash distribution policy defines minimum equity-to-total-capitalization ratios to be used by the Northern Border Pipeline Management Committee to establish the timing and amount of required capital contributions. In addition, any shortfall due to the inability to refinance maturing debt will be funded by capital contributions.

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 are effective January 1, 2013. The new long-term transportation rates are approximately 11 percent lower compared with previous rates and are expected to reduce our future equity earnings and cash distributions from Northern Border Pipeline.

L. RELATED-PARTY TRANSACTIONS

Intersegment and affiliate sales are recorded on the same basis as sales to unaffiliated customers. Our Natural Gas Gathering and Processing segment sells natural gas to ONEOK and its subsidiaries. A portion of our Natural Gas Pipelines segment's revenues are from ONEOK and its subsidiaries. Additionally, 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.

Under the Services Agreement with ONEOK and ONEOK Partners GP (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 and ONEOK Services Company 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. 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 having no direct basis for allocation is allocated by the modified Distrigas method, a method using a combination of ratios that includes gross plant and investment, operating income and payroll expense. It is not practicable to determine what these general overhead costs would be on a stand-alone basis. All costs directly charged or allocated to us are included in our Consolidated Statements of Income.

Our derivative contracts with OES are discussed under "Credit Risk" in Note C.

The following table sets forth the transactions with related parties for the periods indicated:

	Years Ended December 31,		
	2012	**2011**	**2010**
	(Thousands of dollars)		
Revenues	**$ 352,099**	$ 403,603	$ 457,740
Expenses			
Cost of sales and fuel	**$ 33,094**	$ 48,163	$ 53,107
Administrative and general expenses	**246,050**	251,239	207,282
Total expenses	**$ 279,144**	$ 299,402	$ 260,389

ONEOK Partners GP made additional general partner contributions to us of $19 million and $6.8 million in 2012 and 2010, respectively, to maintain its 2-percent general partner interest in connection with the issuances of common units. See Note H for additional information about cash distributions paid to ONEOK for its general partner and limited partner interests.

Previously, we had a Processing and Services Agreement with ONEOK and OBPI, under which we contracted for all of OBPI's rights, including all of the capacity of the Bushton Plant, reimbursing OBPI for all costs associated with the operation and maintenance of the Bushton Plant and its obligations under equipment leases covering portions of the Bushton Plant. On June 30, 2011, we acquired OBPI and terminated the equipment lease agreements. The total amount paid by us to complete the transactions was approximately $94.2 million, which included the reimbursement to ONEOK of obligations related to the Processing and Services Agreement.

M. COMMITMENTS AND CONTINGENCIES

Commitments - Operating leases represent future minimum lease payments under noncancelable leases covering office space, pipeline equipment and vehicles. Firm transportation and storage contracts are fixed-price contracts that provide us with firm transportation and storage capacity. Rental expense in 2012, 2011 and 2010 was not material. The following table sets forth our operating lease and firm transportation and storage contracts payments for the periods presented:

	Operating Leases	Firm Transportation and Storage Contracts	Total
		(Millions of dollars)	
2013	$ 0.6	$ 16.3	$ 16.9
2014	1.8	13.2	15.0
2015	0.4	13.0	13.4
2016	0.3	11.7	12.0
2017	0.2	10.1	10.3
Thereafter	0.3	42.3	42.6
Total	$ 3.6	$ 106.6	$ 110.2

Environmental Matters - We are subject to multiple historical, wildlife preservation and environmental laws and regulations, which 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 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. Revised or additional regulations that result in increased compliance costs or additional operating restrictions could have a material adverse effect on our business, financial condition, 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 had no material effects on earnings or cash flows during the years ended December 31, 2012, 2011 and 2010.

In May 2010, the EPA finalized the "Tailoring Rule" that regulates greenhouse gas emissions at new or modified facilities that meet certain criteria. Affected facilities are required to review best available control technology, conduct air-quality analysis, impact analysis and public reviews with respect to such emissions. The rule was phased in beginning January 2011, and at current emission threshold levels, has not had a material impact on our existing facilities. The EPA has stated it will consider lowering the threshold levels over the next five years, which could increase the impact on our existing facilities; however, potential costs, fees or expenses associated with the potential adjustments are unknown.

In 2010, the EPA issued a rule on air-quality standards titled, "National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines," also known as RICE NESHAP, which initially included a compliance date in 2013. Subsequent industry appeals and settlements with the EPA have extended timelines associated with the final RICE NESHAP rule. While the rule could require capital expenditures for the purchase and installation of new emissions-control equipment, we do not expect these expenditures will have a material impact on our results of operations, financial position or cash flows.

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 gas industry, including natural gas production, processing, transmission and underground storage. 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. Further, pursuant to various industry comments, administrative petitions for reconsideration and/or judicial appeals of portions of the NSPS final rule, the EPA has indicated it may provide certain responses, amendments and/or policy guidance to amend or clarify portions of the final rule in 2013. We anticipate that if the EPA issues additional responses, amendments and/or policy guidance on the final rule, it will reduce the anticipated capital, operations and maintenance costs resulting from the regulation. Generally, the NSPS final rule will require expenditures for updated emissions controls, monitoring and record-keeping requirements at affected facilities. We do not expect these expenditures will have a material impact on our results of operations, financial position or cash flows.

Pipeline Safety - We are subject to PHMSA regulations, including 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 new law increased the 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 of 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.

Financial Markets Legislation - The Dodd-Frank Act represents a far-reaching overhaul of the framework for regulation of United States financial markets. Various regulatory agencies, including the SEC and the CFTC, have proposed regulations for implementation of many of the provisions of the Dodd-Frank Act. The CFTC has issued final regulations for many provisions of the Dodd-Frank Act that have varying effective dates for compliance, but others remain outstanding. Based on our assessment of the regulations issued to date and those proposed, we expect to be able to continue to participate in financial markets for hedging certain risks inherent in our business, including commodity and interest-rate risks; however, the capital requirements and costs of hedging may increase as a result of the regulations. We also may incur additional costs associated with our compliance with the new regulations and anticipated additional record keeping, reporting and disclosure obligations; however, we do not believe the costs will be material. These requirements could affect adversely market liquidity and pricing of derivative contracts, making it more difficult to execute our risk-management strategies in the future. Also, the anticipated increased costs of compliance by dealers and counterparties likely will be passed on to customers, which could decrease the benefits of hedging to us and could reduce our profitability and liquidity.

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 liquidity.

N. 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 Pipelines segment operates regulated interstate and intrastate natural gas transmission pipelines and natural gas storage facilities; and
- our Natural Gas Liquids segment gathers, treats, fractionates and transports NGLs and stores, markets and distributes NGL products.

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 and transportation costs.

Customers - The primary customers for our Natural Gas Gathering and Processing segment are major and independent crude oil and natural gas production companies. Customers served by our Natural Gas Pipelines segment include natural gas distribution companies, electric-generation companies, natural gas marketing companies and petrochemical 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.

For the year ended December 31, 2012, we had no single customer from which we received 10 percent or more of our consolidated revenues. For the year ended December 31, 2011, we had one customer, Dow Hydrocarbons and Resources, L.L.C., from which we received $1.2 billion, or approximately 11 percent, of our consolidated revenues. All of these revenues were earned in our Natural Gas Liquids segment. For the year ended December 31, 2010, we had no single customer from which we received 10 percent or more of our consolidated revenues.

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

(a) - 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.
(b) - 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.

Year Ended December 31, 2011	Natural Gas Gathering and Processing	Natural Gas Pipelines (a)	Natural Gas Liquids (b)	Other and Eliminations	Total
	(Thousands of dollars)				
Sales to unaffiliated customers	$ 363,491	$ 230,389	$ 10,325,124	$ —	$ 10,919,004
Sales to affiliated customers	298,040	105,563	—	—	403,603
Intersegment revenues	871,943	1,847	36,155	(909,945)	—
Total revenues	$ 1,533,474	$ 337,799	$ 10,361,279	$ (909,945)	$ 11,322,607
Net margin	$ 402,854	$ 284,393	$ 891,788	$ (1,655)	$ 1,577,380
Operating costs	153,686	108,635	198,907	(1,864)	459,364
Depreciation and amortization	68,255	45,390	63,904	—	177,549
Loss on sale of assets	(299)	(286)	(378)	—	(963)
Operating income	$ 180,614	$ 130,082	$ 628,599	$ 209	$ 939,504
Equity earnings from investments	$ 30,523	$ 76,870	$ 19,853	$ —	$ 127,246
Investments in unconsolidated affiliates	$ 324,610	$ 423,603	$ 475,185	$ —	$ 1,223,398
Total assets	$ 2,424,626	$ 1,886,046	$ 4,595,852	$ 40,152	$ 8,946,676
Noncontrolling interests in consolidated subsidiaries	$ —	$ 5,171	$ —	$ (59)	$ 5,112
Capital expenditures	$ 623,739	$ 37,846	$ 401,278	$ 520	$ 1,063,383

(a) - Our Natural Gas Pipelines segment has regulated and non-regulated operations. Our Natural Gas Pipelines segment's regulated operations had revenues of $265.2 million, net margin of $218.2 million and operating income of $88.0 million.
(b) - Our Natural Gas Liquids segment has regulated and non-regulated operations. Our Natural Gas Liquids segment's regulated operations had revenues of $393.3 million, of which $267.0 million related to sales within the segment, net margin of $250.8 million and operating income of $144.8 million.

Year Ended December 31, 2010		Natural Gas Gathering and Processing		Natural Gas Pipelines (a)		Natural Gas Liquids (b)		Other and Eliminations		Total
						(Thousands of dollars)				
Sales to unaffiliated customers	$	236,620	$	239,749	$	7,741,791	$	—	$	8,218,160
Sales to affiliated customers		347,909		109,831		—		—		457,740
Intersegment revenues		733,374		1,486		33,260		(768,120)		—
Total revenues	$	1,317,903	$	351,066	$	7,775,051	$	(768,120)	$	8,675,900
Net margin	$	351,372	$	300,174	$	499,627	$	(6,320)	$	1,144,853
Operating costs		136,757		96,525		173,940		(3,746)		403,476
Depreciation and amortization		60,700		44,133		68,875		—		173,708
Gain (loss) on sale of assets		(359)		3,488		15,503		—		18,632
Operating income	$	153,556	$	163,004	$	272,315	$	(2,574)	$	586,301
Equity earnings from investments	$	27,495	$	68,761	$	5,624	$	—	$	101,880
Investments in unconsolidated affiliates	$	324,936	$	392,079	$	471,109	$	—	$	1,188,124
Total assets	$	1,809,469	$	1,887,595	$	4,224,410	$	(1,374)	$	7,920,100
Noncontrolling interests in consolidated subsidiaries	$	—	$	5,161	$	—	$	15	$	5,176
Capital expenditures	$	216,049	$	27,621	$	107,933	$	1,111	$	352,714

(a) - Our Natural Gas Pipelines segment has regulated and non-regulated operations. Our Natural Gas Pipelines segment's regulated operations had revenues of $279.8 million, net margin of $234.9 million and operating income of $116.1 million.
(b) - Our Natural Gas Liquids segment has regulated and non-regulated operations. Our Natural Gas Liquids segment's regulated operations had revenues of $332.4 million, of which $214.5 million related to sales within the segment, net margin of $244.2 million and operating income of $134.8 million.

O. QUARTERLY FINANCIAL DATA (UNAUDITED)

Year Ended December 31, 2012		First Quarter		Second Quarter		Third Quarter		Fourth Quarter
		(Thousands of dollars, except per unit amounts)						
Revenues	**$**	**2,594,088**	**$**	**2,124,806**	**$**	**2,547,460**	**$**	**2,915,797**
Net margin	**$**	**421,090**	**$**	**401,462**	**$**	**419,737**	**$**	**399,543**
Net income	**$**	**238,964**	**$**	**206,580**	**$**	**232,377**	**$**	**210,507**
Net income attributable to ONEOK Partners, L.P.	**$**	**238,843**	**$**	**206,467**	**$**	**232,275**	**$**	**210,405**
Limited partners' per unit net income	**$**	**0.91**	**$**	**0.69**	**$**	**0.78**	**$**	**0.66**

Year Ended December 31, 2011		First Quarter		Second Quarter		Third Quarter		Fourth Quarter
		(Thousands of dollars, except per unit amounts)						
Revenues	$	2,499,610	$	2,784,219	$	2,903,576	$	3,135,202
Net margin	$	329,554	$	359,540	$	394,006	$	494,280
Net income	$	151,057	$	171,255	$	209,824	$	298,756
Net income attributable to ONEOK Partners, L.P.	$	150,910	$	171,124	$	209,686	$	298,599
Limited partners' per unit net income	$	0.58	$	0.67	$	0.84	$	1.26

P. 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. The Intermediate Partnership's guarantee is 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. We have recast prior period amounts in the condensed consolidating statements of cash flows to revise the classification of cash dividends received by the Parent from the Guarantor Subsidiary from financing to operating activities.

Condensed Consolidating Statements of Income

	Year Ended December 31, 2012				
	Parent	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
			(Millions of dollars)		
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 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

	Year Ended December 31, 2011				
	Parent	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
			(Millions of dollars)		
Revenues	$ —	$ —	$ 11,322.6	$ —	$ 11,322.6
Cost of sales and fuel	—	—	9,745.2	—	9,745.2
Net margin	—	—	1,577.4	—	1,577.4
Operating expenses					
Operations and maintenance	—	—	414.5	—	414.5
Depreciation and amortization	—	—	177.5	—	177.5
General taxes	—	—	44.9	—	44.9
Total operating expenses	—	—	636.9	—	636.9
Gain (loss) on sale of assets	—	—	(1.0)	—	(1.0)
Operating income	—	—	939.5	—	939.5
Equity earnings from investments	830.3	830.3	50.9	(1,584.3)	127.2
Allowance for equity funds used during construction	—	—	2.3	—	2.3
Other income (expense), net	215.8	215.8	(2.4)	(431.6)	(2.4)
Interest expense	(215.8)	(215.8)	(223.1)	431.6	(223.1)
Income before income taxes	830.3	830.3	767.2	(1,584.3)	843.5
Income taxes	—	—	(12.6)	—	(12.6)
Net income	830.3	830.3	754.6	(1,584.3)	830.9
Less: Net income attributable to noncontrolling interests	—	—	0.6	—	0.6
Net income attributable to ONEOK Partners, L.P.	$ 830.3	$ 830.3	$ 754.0	$ (1,584.3)	$ 830.3

	Year Ended December 31, 2010				
	Parent	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
			(Millions of dollars)		
Revenues	$ —	$ —	$ 8,675.9	$ —	$ 8,675.9
Cost of sales and fuel	—	—	7,531.0	—	7,531.0
Net margin	—	—	1,144.9	—	1,144.9
Operating expenses					
Operations and maintenance	—	—	363.5	—	363.5
Depreciation and amortization	—	—	173.7	—	173.7
General taxes	—	—	40.0	—	40.0
Total operating expenses	—	—	577.2	—	577.2
Gain on sale of assets	—	—	18.6	—	18.6
Operating income	—	—	586.3	—	586.3
Equity earnings from investments	472.7	472.7	33.8	(877.3)	101.9
Allowance for equity funds used during construction	—	—	1.0	—	1.0
Other income (expense), net	196.0	196.0	3.5	(392.0)	3.5
Interest expense	(196.0)	(196.0)	(204.3)	392.0	(204.3)
Income before income taxes	472.7	472.7	420.3	(877.3)	488.4
Income taxes	—	—	(15.1)	—	(15.1)
Net income	472.7	472.7	405.2	(877.3)	473.3
Less: Net income attributable to noncontrolling interests	—	—	0.6	—	0.6
Net income attributable to ONEOK Partners, L.P.	$ 472.7	$ 472.7	$ 404.6	$ (877.3)	$ 472.7

Condensed Consolidating Statements of Comprehensive Income

	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**

	Year Ended December 31, 2011				
	Parent	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
			(Millions of dollars)		
Net income	$ 830.3	$ 830.3	$ 754.6	$ (1,584.3)	$ 830.9
Other comprehensive income (loss)					
Unrealized gains (losses) on derivatives	(59.4)	18.2	18.2	(36.4)	(59.4)
Realized (gains) losses on derivatives recognized in net income	2.0	1.5	1.5	(3.0)	2.0
Total other comprehensive income (loss)	(57.4)	19.7	19.7	(39.4)	(57.4)
Comprehensive income	772.9	850.0	774.3	(1,623.7)	773.5
Less: Comprehensive income attributable to noncontrolling interests	—	—	0.6	—	0.6
Comprehensive income attributable to ONEOK Partners, L.P.	$ 772.9	$ 850.0	$ 773.7	$ (1,623.7)	$ 772.9

	Year Ended December 31, 2010				
	Parent	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
			(Millions of dollars)		
Net income	$ 472.7	$ 472.7	$ 405.2	$ (877.3)	$ 473.3
Other comprehensive income (loss)					
Unrealized gains (losses) on derivatives	31.3	31.3	31.3	(62.6)	31.3
Realized (gains) losses on derivatives recognized in net income	(3.0)	(3.0)	(3.0)	6.0	(3.0)
Total other comprehensive income (loss)	28.3	28.3	28.3	(56.6)	28.3
Comprehensive income	501.0	501.0	433.5	(933.9)	501.6
Less: Comprehensive income attributable to noncontrolling interests	—	—	0.6	—	0.6
Comprehensive income attributable to ONEOK Partners, L.P.	$ 501.0	$ 501.0	$ 432.9	$ (933.9)	$ 501.0

Condensed Consolidating Balance Sheets

	December 31, 2012				
	Parent	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
Assets			*(Millions of dollars)*		
Current assets					
Cash and cash equivalents	$ —	$ 537.1	$ —	$ —	$ 537.1
Accounts receivable, net	—	—	914.0	—	914.0
Affiliate receivables	—	—	16.1	—	16.1
Gas and natural gas liquids in storage	—	—	235.8	—	235.8
Commodity imbalances	—	—	89.7	—	89.7
Other current assets	10.9	—	88.1	—	99.0
Total current assets	10.9	537.1	1,343.7	—	1,891.7
Property, plant and equipment					
Property, plant and equipment	—	—	8,585.2	—	8,585.2
Accumulated depreciation and amortization	—	—	1,440.9	—	1,440.9
Net property, plant and equipment	—	—	7,144.3	—	7,144.3
Investments and other assets					
Investments in unconsolidated affiliates	4,458.7	3,858.9	828.6	(7,924.8)	1,221.4
Intercompany notes receivable	4,770.6	4,833.3	—	(9,603.9)	—
Goodwill and intangible assets	—	—	645.8	—	645.8
Other assets	31.6	—	24.4	—	56.0
Total investments and other assets	9,260.9	8,692.2	1,498.8	(17,528.7)	1,923.2
Total assets	$ 9,271.8	$ 9,229.3	$ 9,986.8	$ (17,528.7)	$ 10,959.2
Liabilities and partners' equity					
Current liabilities					
Current maturities of long-term debt	$ —	$ —	$ 7.6	$ —	$ 7.6
Accounts payable	—	—	1,058.0	—	1,058.0
Affiliate payables	—	—	75.7	—	75.7
Commodity imbalances	—	—	273.2	—	273.2
Other current liabilities	76.7	—	79.2	—	155.9
Total current liabilities	76.7	—	1,493.7	—	1,570.4
Intercompany debt	—	4,770.6	4,833.3	(9,603.9)	—
Long-term debt, excluding current maturities	4,736.4	—	67.2	—	4,803.6
Deferred credits and other liabilities	—	—	121.7	—	121.7
Commitments and contingencies					
Equity					
Equity excluding noncontrolling interests in consolidated subsidiaries	4,458.7	4,458.7	3,466.1	(7,924.8)	4,458.7
Noncontrolling interests in consolidated subsidiaries	—	—	4.8	—	4.8
Total equity	4,458.7	4,458.7	3,470.9	(7,924.8)	4,463.5
Total liabilities and equity	$ 9,271.8	$ 9,229.3	$ 9,986.8	$ (17,528.7)	$ 10,959.2

	December 31, 2011				
	Parent	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
Assets			*(Millions of dollars)*		
Current assets					
Cash and cash equivalents	$ —	$ 35.1	$ —	$ —	$ 35.1
Accounts receivable, net	—	—	922.2	—	922.2
Affiliate receivables	—	—	4.1	—	4.1
Gas and natural gas liquids in storage	—	—	202.2	—	202.2
Commodity imbalances	—	—	62.9	—	62.9
Other current assets	—	—	79.4	—	79.4
Total current assets	—	35.1	1,270.8	—	1,305.9
Property, plant and equipment					
Property, plant and equipment	—	—	6,963.7	—	6,963.7
Accumulated depreciation and amortization	—	—	1,259.7	—	1,259.7
Net property, plant and equipment	—	—	5,704.0	—	5,704.0
Investments and other assets					
Investments in unconsolidated affiliates	3,441.4	4,080.7	807.6	(7,106.3)	1,223.4
Intercompany notes receivable	3,913.9	3,239.5	—	(7,153.4)	—
Goodwill and intangible assets	—	—	653.5	—	653.5
Other assets	24.7	—	35.2	—	59.9
Total investments and other assets	7,380.0	7,320.2	1,496.3	(14,259.7)	1,936.8
Total assets	$ 7,380.0	$ 7,355.3	$ 8,471.1	$ (14,259.7)	$ 8,946.7
Liabilities and partners' equity					
Current liabilities					
Current maturities of long-term debt	$ 350.0	$ —	$ 11.1	$ —	$ 361.1
Accounts payable	—	—	1,049.3	—	1,049.3
Affiliate payables	—	—	41.1	—	41.1
Commodity imbalances	—	—	202.5	—	202.5
Other current liabilities	147.9	—	86.7	—	234.6
Total current liabilities	497.9	—	1,390.7	—	1,888.6
Intercompany debt	—	3,913.9	3,239.5	(7,153.4)	—
Long-term debt, excluding current maturities	3,440.7	—	74.9	—	3,515.6
Deferred credits and other liabilities	—	—	96.0	—	96.0
Commitments and contingencies					
Equity					
Equity excluding noncontrolling interests in consolidated subsidiaries	3,441.4	3,441.4	3,664.9	(7,106.3)	3,441.4
Noncontrolling interests in consolidated subsidiaries	—	—	5.1	—	5.1
Total equity	3,441.4	3,441.4	3,670.0	(7,106.3)	3,446.5
Total liabilities and equity	$ 7,380.0	$ 7,355.3	$ 8,471.1	$ (14,259.7)	$ 8,946.7

Condensed Consolidating Statements of Cash Flows

	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 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**

	Year Ended December 31, 2011				
	Parent	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
			(Millions of dollars)		
Operating activities					
Cash provided by operating activities	$ 609.4	$ 76.4	$ 1,053.3	$ (609.4)	$ 1,129.7
Investing activities					
Capital expenditures (less allowance for equity funds used during construction)	—	—	(1,063.4)	—	(1,063.4)
Contributions to unconsolidated affiliates	—	—	(64.5)	—	(64.5)
Distributions received from unconsolidated affiliates	—	22.7	1.0	—	23.7
Proceeds from sale of assets	—	—	1.1	—	1.1
Cash provided by (used in) investing activities	—	22.7	(1,125.8)	—	(1,103.1)
Financing activities					
Cash distributions:					
General and limited partners	(609.4)	(609.4)	—	609.4	(609.4)
Noncontrolling interests	—	—	(0.6)	—	(0.6)
Repayment of notes payable, net	(429.9)	—	—	—	(429.9)
Intercompany borrowings (advances), net	(629.6)	544.5	85.1	—	—
Issuance of long-term debt, net of discounts	1,295.5	—	—	—	1,295.5
Long-term debt financing costs	(11.0)	—	—	—	(11.0)
Repayment of long-term debt	(225.0)	—	(12.0)	—	(237.0)
Cash provided by (used in) financing activities	(609.4)	(64.9)	72.5	609.4	7.6
Change in cash and cash equivalents	—	34.2	—	—	34.2
Cash and cash equivalents at beginning of period	—	0.9	—	—	0.9
Cash and cash equivalents at end of period	$ —	$ 35.1	$ —	$ —	$ 35.1

	Year Ended December 31, 2010				
	Parent	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
			(Millions of dollars)		
Operating activities					
Cash provided by operating activities	$ 563.2	$ 68.1	$ 427.1	$ (563.2)	$ 495.2
Investing activities					
Capital expenditures (less allowance for equity funds used during construction)	—	—	(352.7)	—	(352.7)
Contributions to unconsolidated affiliates	—	—	(1.3)	—	(1.3)
Distributions received from unconsolidated affiliates	—	17.8	—	—	17.8
Proceeds from sale of assets	—	—	428.4	—	428.4
Cash provided by investing activities	—	17.8	74.4	—	92.2
Financing activities					
Cash distributions:					
General and limited partners	(563.2)	(563.2)	—	563.2	(563.2)
Noncontrolling interests	—	—	(1.0)	—	(1.0)
Repayment of notes payable, net	(93.1)	—	—	—	(93.1)
Intercompany borrowings (advances), net	13.6	475.0	(488.6)	—	—
Repayment of long-term debt	(250.0)	—	(11.9)	—	(261.9)
Issuance of common units, net of issuance costs	322.7	—	—	—	322.7
Contribution from general partner	6.8	—	—	—	6.8
Cash used in financing activities	(563.2)	(88.2)	(501.5)	563.2	(589.7)
Change in cash and cash equivalents	—	(2.3)	—	—	(2.3)
Cash and cash equivalents at beginning of period	—	3.2	—	—	3.2
Cash and cash equivalents at end of period	$ —	$ 0.9	$ —	$ —	$ 0.9

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 and the Chief Financial Officer of ONEOK Partners GP, our general partner, who are the equivalent of our principal executive and principal financial officers, 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* 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, 2012.

Our internal control over financial reporting as of December 31, 2012, 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, 2012, 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 nine 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 seven of the nine members of our Board of Directors, Julie H. Edwards, Steven J. Malcolm, Jim W. Mogg, Gary N. Petersen, Gerald B. Smith, 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 director candidates, 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 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 and our Chief Executive Officer. 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, including the combined chairman and chief executive officer positions, 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 seven 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 2013, our Board of Directors affirmatively determined that Ms. Edwards and Messrs. Malcolm, Mogg, Petersen, Smith, 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 2013, our Board of Directors determined that Ms. Edwards and Messrs. Malcolm, Mogg, Petersen, Smith, 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 also 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 a company-wide 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 risk 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.

The Board 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.

The Board 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 President, Chief Financial Officer, General Counsel and Director - Audit Services as well as our independent registered public accounting firm in executive sessions, at which risk issues are regularly discussed, 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. Some of these individuals are also officers of certain of our subsidiaries and affiliates.

Name	Age	Position
John W. Gibson	60	Chairman of the Board and Chief Executive Officer
Terry K. Spencer	53	President and Member, Board of Directors
Robert F. Martinovich	55	Executive Vice President, Operations
Pierce H. Norton II	53	Executive Vice President, Commercial
Stephen W. Lake	49	Senior Vice President, General Counsel and Assistant Secretary
Derek S. Reiners	41	Senior Vice President, Chief Financial Officer and Treasurer
Sheppard F. Miers III	44	Vice President and Chief Accounting Officer
Julie H. Edwards	54	Member, Board of Directors and Audit Committee
Steven J. Malcolm	64	Member, Board of Directors and Audit Committee
Jim W. Mogg	64	Member, Board of Directors and Audit Committee
Gary N. Petersen	61	Member, Board of Directors, Audit and Conflicts Committees
Gerald B. Smith	62	Member, Board of Directors and Audit Committee
Craig F. Strehl	55	Member, Board of Directors and Vice Chairman, Audit and Conflicts Committees
Gil J. Van Lunsen	70	Member, Board of Directors and Chairman, Audit and Conflicts Committees

John W. Gibson is Chairman and Chief Executive Officer of ONEOK Partners GP and ONEOK. He has served as our Chairman of the Board and Chief Executive Officer since 2007 and also served as President from 2010 through 2011. Since 2007, he has 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 also serves on the Board of Directors of BOK Financial Corporation.

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 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 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. From 2003 to 2005, he served as Vice President and General Manager of Gas Supply and Project Development for ONEOK.

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 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.

Robert F. Martinovich was appointed Executive Vice President, Operations, of ONEOK Partners GP and ONEOK, effective January 1, 2013. Mr. Martinovich served 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.

Pierce H. Norton II was appointed Executive Vice President, Commercial, of ONEOK Partners GP and ONEOK, effective January 1, 2013. He served as Executive Vice President and Chief Operating Officer of ONEOK Partners GP and ONEOK from January 1, 2012, through December 31, 2012. Mr. Norton served as Chief Operating Officer of ONEOK from March 2011 through December 31, 2011. From July 2009 until his appointment as Chief Operating Officer of ONEOK, Mr. Norton was President of ONEOK Distribution Companies, which includes Kansas Gas Service Company, Oklahoma Natural Gas Company and Texas Gas Service Company, responsible for the operations of the Company's three natural gas utilities, energy services segment and environment, and safety and health organization. Mr. Norton was appointed President of our gathering and processing segment in January 2006 and served in that capacity until his appointment as our Executive Vice President - Natural Gas in July 2007.

Mr. Norton began his natural gas industry career in 1982 at Delhi Gas Pipeline, a subsidiary of Texas Oil and Gas Corporation. Mr. Norton later worked for American Oil and Gas and KN Energy. In 2002, Mr. Norton was named president of ONEOK Rockies Midstream, L.L.C., formally known as Bear Paw Energy, which is now a subsidiary of ONEOK Partners.

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.

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.

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 Texas-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, as vice chair of the Audit Committee and as a member of the Executive Compensation Committee. Mr. Malcolm served as President of The Williams Companies, Inc. (Williams) 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 Tulsa Regional Chamber of Commerce. 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 Executive Compensation Committee. Mr. Mogg served as Chairman of the Board of DCP Midstream GP, LLC, the general partner of DCP Midstream Partners, L.P., (DCP Midstream) from August 2005 to April 2007. In addition to presiding over board meetings and providing strategic oversight, he was involved in launching DCP Midstream 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 (Duke Energy) 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 lead director.

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 has 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. 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. In May 2011, Mr. Petersen became President of Energy Technology Unlimited of Minnesota, LLC, a start-up antifreeze recycling company based in Faribault, Minnesota.

Additionally, Mr. Petersen has been a consultant for the past 13 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 total operations. The first 10 years of his Minnegasco career included numerous management positions of continually increasing responsibility in the areas of 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.

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.

Gerald B. Smith was appointed to our Board of Directors in May 2006. Mr. Smith also serves on the Board of Directors of ONEOK and its Executive Compensation Committee. Mr. Smith is Chairman and Chief Executive Officer of Smith, Graham & Co., Investment Advisors, L.P., a global investment management firm, which was founded in 1990. Mr. Smith is a member of the Board of Trustees and chair of the Investment Oversight Committee for The Charles Schwab Family of Funds. He is also a member of the Board of Directors of New York Life Insurance Company and Eaton Corporation plc. He is a director of the Federal Reserve Bank of Dallas, Houston Branch, and serves as chairman of the Texas Southern University Foundation. He is a former director of the Fund Management Board of Robeco Group, Rorento N.V. (Netherlands).

On February 20, 2013, Mr. Smith notified us of his decision, due to other commitments, to resign from the board of directors of ONEOK Partners GP on May 22, 2013. On that date, the number of members of the board of directors of ONEOK Partners GP will be reduced to eight from nine.

Craig F. Strehl was appointed to our Board of Directors in August 2009. Mr. Strehl is an 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 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. Additionally, Mr. Van Lunsen was the Chairman of the Audit Committee of Sirenza Microdevices, Inc. and its predecessor entities in Broomfield, Colorado, from July 2002 until December 2007. 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, 2012, consisted of an annual cash retainer of $115,000. In addition, the chair of our Audit Committee received an additional annual cash fee of $10,000. 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 2012.

2012 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 ($)
Julie H. Edwards	$ 115,000	—	—	—	—	—	$ 115,000
Steven J. Malcolm	$ 115,000	—	—	—	—	—	$ 115,000
Jim W. Mogg	$ 115,000	—	—	—	—	—	$ 115,000
Shelby E. Odell (1)	$ 79,839	—	—	—	—	—	$ 79,839
Gary N. Petersen	$ 128,925	—	—	—	—	—	$ 128,925
Gerald B. Smith	$ 115,000	—	—	—	—	—	$ 115,000
Craig F. Strehl	$ 122,500	—	—	—	—	—	$ 122,500
Gil J. Van Lunsen	$ 128,575	—	—	—	—	—	$ 128,575

(1) Mr. Odell retired from the Board on August 18, 2012.

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 at each in-person meeting of the Board. The chairman of our Audit Committee, presides at regular sessions of the nonmanagement 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 annual self-evaluation of the board. Our Board of Directors recognizes that effective governance is an ongoing process, and the Board will review 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 and 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 will also be provided to our chairman and 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 2012, 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 2012 fiscal year or written representations from certain reporting persons that no Form 5s were required for those persons, we believe that during 2012 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 2013 Proxy Statement as filed with the SEC (ONEOK 2013 Proxy Statement), which is incorporated herein by this reference. A copy of the ONEOK 2013 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.

Under our Services Agreement with ONEOK, 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 2012 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 2012

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	2012	$ 611,531	$ 2,149,828	$ 675,903	$ 2,303,843	$ 94,891	$ 5,835,996
Chairman and Chief Executive Officer	2011	$ 527,595	$ 2,450,386	$ 879,325	$ 897,336	$ 67,718	$ 4,822,360
	2010	$ 492,990	$ 1,912,411	$ 547,767	$ 1,412,014	$ 67,628	$ 4,432,810
Terry K. Spencer	2012	$ 386,230	$ 1,061,643	$ 334,733	$ 342,156	$ 48,544	$ 2,173,306
President	2011	$ 500,000	$ 1,922,800	$ 650,000	$ 305,582	$ 55,764	$ 3,434,146
	2010	$ 415,000	$ 1,330,050	$ 400,000	$ 220,450	$ 45,080	$ 2,410,580
Robert F. Martinovich (5)	2012	$ 321,858	$ 928,938	$ 247,831	$ —	$ 72,973	$ 1,571,600
Executive Vice President, Operations	2011	$ 221,430	$ 699,325	$ 258,335	$ —	$ 47,926	$ 1,227,016
	2010	$ —	$ —	$ —	$ —	$ —	$ —
Curtis L. Dinan	2012	$ 435,000	$ 907,082	$ 300,000	$ 424,560	$ 52,911	$ 2,119,553
Senior Vice President, Natural Gas	2011	$ 394,180	$ 1,007,989	$ 408,093	$ 208,214	$ 43,032	$ 2,061,508
	2010	$ 219,107	$ 440,358	$ 178,024	$ 123,771	$ 25,844	$ 987,104
Sheridan C. Swords	2012	$ 425,000	$ 907,082	$ 345,000	$ 68,477	$ 79,461	$ 1,825,020
Senior Vice President, Natural Gas Liquids	2011	$ 350,000	$ 1,086,800	$ 400,000	$ 43,377	$ 56,897	$ 1,937,074
	2010	$ 315,000	$ 550,180	$ 235,000	$ 34,311	$ 47,780	$ 1,182,271

(1) The amounts included in the table relate to restricted stock units and performance units granted under the ONEOK Long-Term Incentive Plan (LTI Plan) and the ONEOK Equity Compensation Plan, respectively, and reflect the aggregate grant date fair value allocated to us in 2010, 2011 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 L to the ONEOK audited financial statements for the year ended December 31, 2012, included in the ONEOK 2012 Annual Report on Form 10-K filed with the SEC on February 26, 2013.

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	2012	2011	2010
John W. Gibson	$ 3,536,415	$ 4,065,413	$ 3,203,248
Terry K. Spencer	$ 1,746,378	$ 3,190,100	$ 2,212,140
Robert F. Martinovich	$ 1,528,080	$ 1,160,244	$ —
Curtis L. Dinan	$ 1,492,128	$ 1,672,345	$ 737,590
Sheridan C. Swords	$ 1,492,128	$ 1,803,100	$ 913,710

(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 and profitability of ONEOK, the performance of particular business units of ONEOK, and 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 2012 awards under the ONEOK annual short-term incentive plan, see "2012 Annual Short-Term Incentive Awards" in the Executive Compensation Discussion and Analysis section of the ONEOK 2013 Proxy Statement.

(3) The amounts reflected represent the aggregate change during 2012 in the actuarial present value of the named executive officers' accumulated benefits under the Retirement Plan for Employees of ONEOK, Inc. and Subsidiaries and the ONEOK, Inc. Supplemental

Executive Retirement Plan. A description of the Retirement Plan for Employees of ONEOK, Inc. and Subsidiaries and the ONEOK, Inc. Supplemental Executive Retirement Plan will be set forth in the Executive Compensation and Discussion and Analysis section of the ONEOK 2013 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 2012, 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 (4.25 percent for fiscal 2012, down from 5.00 percent in 2011). The Retirement Plan for Employees of ONEOK, Inc. and Subsidiaries 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, Dinan and Swords.

(4) Reflects the portion allocated to us of (i) the amounts paid as ONEOK's dollar-for-dollar match of contributions made by the named executive officer under both the ONEOK, Inc. Nonqualified Deferred Compensation Plan, the Thrift Plan for Employees of ONEOK, Inc. and Subsidiaries and the ONEOK Profit Sharing Plan, (ii) amounts paid for length of service awards, and (iii) the value of shares received under the ONEOK Employee Stock Award Program, as follows:

Name	Year	Match Under Nonqualified Deferred Compensation Plan (a)	Match Under Thrift Plan (b)	Company Contribution to Profit Sharing Plan (c)	Service Award	Stock Award
John W. Gibson	2012	$ 84,970	$ 9,656	$ —	$ —	$ 265
	2011	$ 58,211	$ 8,617	$ —	$ —	$ 557
	2010	$ 58,501	$ 8,052	$ —	$ 137	$ 30
Terry K. Spencer	2012	$ 38,623	$ 9,656	$ —	$ —	$ 265
	2011	$ 39,300	$ 14,700	$ —	$ 250	$ 949
	2010	$ 30,300	$ 14,700	$ —	$ —	$ 55
Robert F. Martinovich	2012	$ 54,877	$ 9,656	$ 8,046	$ 129	$ 265
	2011	$ 32,772	$ 7,233	$ 7,233	$ —	$ 467
	2010	$ —	$ —	$ —	$ —	$ —
Curtis L. Dinan	2012	$ 37,500	$ 15,000	$ —	$ —	$ 411
	2011	$ 28,103	$ 13,634	$ —	$ —	$ 881
	2010	$ 17,748	$ 8,052	$ —	$ —	$ 30
Sheridan C. Swords	2012	$ 63,250	$ 15,000	$ —	$ 800	$ 411
	2011	$ 40,800	$ 14,700	$ —	$ —	$ 949
	2010	$ 33,000	$ 14,700	$ —	$ —	$ 55

(a) Additional information on the ONEOK, Inc. Employee 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 2013 Proxy Statement.

(b) The Thrift Plan for Employees of ONEOK, Inc. and Subsidiaries is a tax-qualified plan that covers 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 nonbargaining unit employees hired after December 31, 2004, employees represented by Local No. 304 of the International Brotherhood of Electrical Workers hired after July 1, 2010, employees represented by the United Steelworkers hired on or after December 15, 2011, and employees who accepted a one-time opportunity to opt out of the ONEOK pension 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.

With respect to Messrs. Gibson, Spencer, Martinovich, Dinan and Swords, these amounts also reflect the allocated portion of tax gross-up payments received in 2010 in the amounts of $22, $25, $0, $14 and $25, respectively, and received in 2011 in the amounts of $333, $448, $221, $414 and $448, respectively, in connection with their receipt of a stock award under the ONEOK Employee Stock Award Program.

With respect to Mr. Gibson, this amount also reflects that portion of the tax gross-up payments received and allocated to us in 2010 in the amount of $99 in connection with his receipt of a ONEOK cash service award.

With respect to Mr. Spencer, this amount also reflects that portion of the tax gross-up payments received and allocated to us in 2011 in the amount of $117 in connection with his receipt of a ONEOK cash service award.

With respect to Mr. Gibson, this amount also reflects the portion of the tax gross-up payments received and allocated to us in 2010 in the amount of $787, with respect to income imputed to him under the Internal Revenue Code in connection with his personal use of ONEOK's aircraft.

In October 2011, ONEOK eliminated tax gross-up payments in connection with an employee's personal use of our aircraft, and, effective January 1, 2012, ONEOK eliminated tax gross-up payments in connection with shares awarded under the ONEOK Employee Stock Award Program and cash service awards.

The named executive officers did not receive perquisites or other personal benefits with an aggregate value of $10,000 or more during 2010, 2011 or 2012.

(5) Mr. Martinovich served as Executive Vice President, Chief Financial Officer and Treasurer of ONEOK Partners GP and ONEOK during 2012.

Potential Post-Employment Payments and Payments upon a Change in Control

The following is a description of the post-employment compensation and benefits that ONEOK provides our named executive officers. The objectives of the post-employment 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; and
- amounts accrued and vested through the Retirement Plan for Employees of ONEOK, Inc. and Subsidiaries and the ONEOK, Inc. Supplemental Executive Retirement Plan.

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 upon completion of the restricted period; 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 base 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 plus target annual 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 Post-Employment 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 upon 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, 2012, 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, 2012. 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 Change-in-Control Plan and, with respect to the performance units, assume a performance factor at target of 100 percent. It should be noted, however, that the salary and target bonus used to calculate such amounts are the base salaries and target bonuses in effect for the named executive officers as of December 31, 2012.

John W. Gibson	Termination Upon Death, Disability or Retirement	Termination Without Cause	Qualifying Termination Following a Change in Control
Cash Severance	$ —	$ —	$ 2,481,400
COBRA Premiums	$ —	$ —	$ 11,174
Equity			
Restricted Stock/Units	$ 1,353,604	$ 1,353,604	$ 1,998,768
Performance Shares/Units	$ 10,296,197	$ —	$ 7,995,071
Total	$ 11,649,801	$ 1,353,604	$ 9,993,839
Total	$ 11,649,801	$ 1,353,604	$ 12,486,413

Terry K. Spencer	Termination Upon Death, Disability or Retirement	Termination Without Cause	Qualifying Termination Following a Change in Control
Cash Severance	$ —	$ —	$ 1,410,480
COBRA Premiums	$ —	$ —	$ 16,857
Equity			
Restricted Stock/Units	$ 574,599	$ 574,599	$ 879,346
Performance Shares/Units	$ 4,228,306	$ —	$ 3,461,553
Total	$ 4,802,905	$ 574,599	$ 4,340,899
Total	$ 4,802,905	$ 574,599	$ 5,768,236

Robert F. Martinovich	Termination Upon Death, Disability or Retirement	Termination Without Cause	Qualifying Termination Following a Change in Control
Cash Severance	$ —	$ —	$ 1,110,100
COBRA Premiums	$ —	$ —	$ 16,857
Equity			
Restricted Stock/Units	$ 515,666	$ 515,666	$ 767,683
Performance Share/Units	$ 3,789,718	$ —	$ 3,014,901
Total	$ 4,305,384	$ 515,666	$ 3,782,584
Total	$ 4,305,384	$ 515,666	$ 4,909,541

Curtis L. Dinan	Termination Upon Death, Disability or Retirement	Termination Without Cause	Qualifying Termination Following a Change in Control
Cash Severance	$ —	$ —	$ 1,435,500
COBRA Premiums	$ —	$ —	$ 25,814
Equity			
Restricted Stock/Units	$ 504,668	$ 504,688	$ 765,225
Performance Shares/Units	$ 3,815,960	$ —	$ 3,060,900
Total	$ 4,320,648	$ 504,688	$ 3,826,125
Total	$ 4,320,648	$ 504,688	$ 5,287,439

Sheridan C. Swords	Termination Upon Death, Disability or Retirement	Termination Without Cause	Qualifying Termination Following a Change in Control
Cash Severance	$ —	$ —	$ 1,402,500
COBRA Premiums	$ —	$ —	$ 25,355
Equity			
Restricted Stock/Units	$ 423,938	$ 423,938	$ 679,725
Performance Shares/Units	$ 3,089,210	$ —	$ 2,676,150
Total	$ 3,513,148	$ 423,938	$ 3,355,875
Total	$ 3,513,148	$ 423,938	$ 4,783,730

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 February 1, 2013. 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	13.5%	72,988,252	100%	41.4% (1)
100 West Fifth Street					
Tulsa, OK 74103-4298					

(1) Does not reflect the general partner's 2 percent interest, which is wholly owned by ONEOK.

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, 2013, 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	51,000	*	—	—	*	770,586	(3)	*
Curtis L. Dinan	20,000	*	—	—	*	136,824	(4)	*
Robert F. Martinovich	288	*	—	—	*	149,076	(5)	*
Terry K. Spencer	—	—	—	—	—	216,675		*
Sheridan C. Swords	—	—	—	—	—	86,854	(6)	*
Gary N. Petersen	20,284	*	—	—	*	—		*
Gerald B. Smith	—	—	—	—	—	1,500		*
Gil J. Van Lunsen	4,000	*	—	—	*	—		—
Julie H. Edwards	—	—	—	—	—	33,690		*
Steven J. Malcolm	—	—	—	—	—	5,332		*
Jim W. Mogg	2,000	*	—	—	*	—		—
Craig F. Strehl	9,400	*	—	—	*	—		—
All directors and executive officers as a group	122,928	*	—	—	*	1,578,718		*

* 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, 2013.

(3) Excludes 82,782 shares, the receipt of which was deferred upon vesting in January 2010; 98,550 shares, the receipt of which was deferred upon vesting in January 2011; and 295,544 shares, the receipt of which was deferred upon vesting in January 2012, in each case under the deferral provisions of the ONEOK Equity Compensation Plan, and which shares will be issued to Mr. Gibson on July 17, 2013, 2014 and 2015, respectively, or upon his separation of service from ONEOK, whichever is later.

(4) Excludes 25,130 shares, the receipt of which was deferred upon vesting in January 2010; 27,594 shares, the receipt of which was deferred upon vesting in January 2011; and 74,504 shares, the receipt of which was deferred upon vesting in January 2012, in each case under the deferral provisions of the ONEOK Equity Compensation Plan, and which shares will be issued to Mr. Dinan upon his separation of services from the company.

(5) Excludes 11,418 shares, the receipt of which was deferred upon vesting in January 2011, under the deferral provisions of the ONEOK Equity Compensation Plan, and which shares will be issued to Mr. Martinovich upon his separation of services from the company.

(6) Excludes 2,771 shares, the receipt of which was deferred upon vesting in January 2010 and 11,413 shares, the receipt of which was deferred upon vesting in January 2011, in each case under under the deferral provisions of the ONEOK Equity Compensation Plan, and which shares will be issued to Mr. Swords upon his separation of service from the company.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Related-Person Transactions

The Board of Directors of our general partner 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. 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 43.4-percent ownership interest in us at December 31, 2012. In 2012, we paid total cash distributions to ONEOK of $436.8 million, which included $186.1 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 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 reflected in our Consolidated Statements of Income. In 2012, the aggregate amount charged by ONEOK and their affiliates to us for their services was approximately $246.1 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 $253.1 million of natural gas to ONEOK and its subsidiaries during 2012. Of our Natural Gas Pipelines segment's revenues, $99.0 million were from ONEOK and its subsidiaries during 2012 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 2012, the aggregate amount charged by ONEOK and its affiliates to us for their services was approximately $33.1 million.

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 2012, Northern Border Pipeline's revenue for capacity contracted on a firm basis included $5.6 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 2012, Overland Pass Pipeline Company's revenue for capacity contracted on a firm basis included $28.0 million from us.

Bushton Plant - Previously, we had a Processing and Services Agreement with ONEOK and OBPI, under which we contracted for all of OBPI's rights, including all of the capacity of the Bushton Plant, reimbursing OBPI for all costs associated with the operation and maintenance of the Bushton Plant and its obligations under equipment leases covering portions of the Bushton Plant. On June 30, 2011, we acquired OBPI and OBPI closed the purchase option and terminated the equipment lease agreements. The total amount paid by us to complete the transactions was approximately $94.2 million, which included the reimbursement to ONEOK of obligations related to the Processing and Services Agreement.

Derivative Contracts - ONEOK Energy Services Company ("OES"), a subsidiary of ONEOK, from time to time enters into commodity derivative contracts on behalf of our Natural Gas Gathering and Processing segment. We have an indemnification agreement with OES in which we have agreed to indemnify and hold OES harmless from any liability OES may incur solely as a result of entering into financial hedges on our behalf. See Note C of the Notes to Consolidated Financial Statements in this Annual Report for a discussion of our derivative instruments and hedging activities.

Relationship with TransCanada

ONEOK Partners GP and an affiliate of TransCanada entered into a transition services agreement for the transfer of the operator function to the affiliate of TransCanada from ONEOK Partners GP, effective April 1, 2007. Northern Border Pipeline agreed to pay ONEOK Partners GP an amount up to $1.0 million per year for years 2007 through 2011 to reimburse ONEOK Partners GP for shared equipment and furnishings acquired by ONEOK Partners GP and used to support Northern Border Pipeline operations.

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 2012 and 2011 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, 2012 and 2011:

	2012	2011
	(Thousands of dollars)	
Audit fees	$ 1,483.9	$ 1,362.5
Audit-related fees	—	—
Tax fees (1)	686.7	693.9
All other fees (2)	0.8	1.0
Total	$ 2,171.4	$ 2,057.4

(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 for the independent auditor. In recognition of this responsibility, the Audit Committee has established a policy with respect to the pre-approval of audit and permissible nonaudit services provided by the independent auditor.

Prior to engagement of PricewaterhouseCoopers LLP as our independent auditor for the 2012 audit, a plan was submitted to and approved by the Audit Committee setting forth the services expected to be rendered during 2012 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 for services for which fees are not determinable on an annual basis, are preapproved if the fees for such services will not exceed $75,000. In addition, the policy provides that the Audit Committee may delegate preapproval authority to one or more of its members. The member to whom such authority is delegated must report, for informational purposes only, any preapproval decisions to the Audit Committee at its next scheduled meeting.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(2) Financial Statements Schedules

All schedules have been omitted because of the absence of conditions under which they are required.

(3) Exhibits

3.0 Amendment No. 2 to Third Amended and Restated Agreement of Limited Partnership of ONEOK Partners, L.P. dated July 12, 2011 (incorporated by reference to Exhibit 3.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on July 13, 2011 (File No. 1-12202)).

3.1 Northern Border Partners, L.P. Certificate of Limited Partnership dated July 12, 1993, Certificate of Amendment dated February 16, 2001, and Certificate of Amendment dated May 20, 2003 (incorporated by reference to Exhibit 3.1 to Northern Border Partners, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2004, filed on March 14, 2005 (File No. 1-12202)).

3.2 Certificate of Amendment to Certificate of Limited Partnership of Northern Border Partners, L.P. dated May 17, 2006 (incorporated by reference to Exhibit 3.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on May 23, 2006 (File No. 1-12202)).

3.3 Third Amended and Restated Agreement of Limited Partnership of ONEOK Partners, L.P. dated as of September 15, 2006 (incorporated by reference to Exhibit 3.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on September 19, 2006 (File No. 1-12202)).

3.4 Certificate of Formation of ONEOK Partners GP, L.L.C., as amended, dated as of May 15, 2006 (incorporated by reference to Exhibit 3.5 to ONEOK Partners, L.P.'s Quarterly Report on Form 10-Q for the period ended June 30, 2006, filed on August 4, 2006 (File No. 1-12202)).

3.5 Amendment No. 3 to Third Amended and Restated Agreement of Limited Partnership of ONEOK Partners, L.P. (incorporated by reference to Exhibit 3.1 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on February 17, 2012 (File No. 1-12202)).

3.6	Certificate of Limited Partnership of Northern Border Intermediate Limited Partnership dated July 12, 1993, Certificate of Amendment dated February 16, 2001, and Certificate of Amendment dated May 20, 2003 (incorporated by reference to Exhibit 3.3 to Northern Border Partners, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2004, filed on March 14, 2005 (File No 1-12202)).
3.7	Certificate of Amendment to Certificate of Limited Partnership of Northern Border Intermediate Limited Partnership dated May 17, 2006 (incorporated by reference to Exhibit 3.3 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on May 23, 2006 (File No. 1-12202)).
3.8	Certificate of Amendment to Certificate of Limited Partnership of ONEOK Partners Intermediate Limited Partnership dated September 15, 2006 (incorporated by reference to Exhibit 3.2 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on September 19, 2006 (File No. 1-12202)).
3.9	Second Amended and Restated Agreement of Limited Partnership of ONEOK Partners Intermediate Limited Partnership dated as of May 17, 2006 (incorporated by reference to Exhibit 3.4 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on May 23, 2006 (File No. 1-12202)).
3.10	Amendment No. 1 to Second Amended and Restated Agreement of Limited Partnership of ONEOK Partners Intermediate Limited Partnership dated as of September 15, 2006 (incorporated by reference to Exhibit 3.3 to ONEOK Partners, L.P.'s Current Report on Form 8-K filed on September 19, 2006 (File No. 1-12202)).
3.11	Certificate of Formation of ONEOK ILP GP, L.L.C. dated May 12, 2006 (incorporated by reference to Exhibit 4.11 to ONEOK Partners, L.P.'s Registration Statement on Form S-3 filed on September 19, 2006 (File No. 333-137419)).
3.12	Not used.
3.13	Amendment No. 1 to Third Amended and Restated Agreement of Limited Partnership of ONEOK Partners, L.P. dated July 20, 2007 (incorporated by reference to Exhibit 3.1 to ONEOK Partners, L.P.'s Quarterly Report on Form 10-Q 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% 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% 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	Not used.
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	Not used.
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	Not used.
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. 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. 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	Not used.
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	Not used.
10.5	Not used.

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).
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).
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 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, swing line 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, 2012, 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, swing line 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 August 2, 2011 (File No. 001-12202)).
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 August 2, 2011 (File No. 001-12202)).
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)).

12	Computation of Ratio of Earnings to Fixed Charges for the years ended December 31, 2012, 2011, 2010, 2009 and 2008.
21	Required information concerning the registrant's subsidiaries.
23.1	Consent of Independent Registered Public Accounting Firm - PricewaterhouseCoopers LLP.
31.1	Certification of John W. Gibson 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 John W. Gibson 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, 2012, 2011 and 2010; (iii) Consolidated Statements of Comprehensive Income for the years ended December 31, 2012, 2011 and 2010; (iv) Consolidated Balance Sheets at December 31, 2012 and 2011; (v) Consolidated Statements of Cash Flows for the years ended December 31, 2012, 2011 and 2010; (vi) Consolidated Statement of Changes in Equity for the years ended December 31, 2012, 2011 and 2010; 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 26, 2013

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 26th day of February 2013.

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

GLOSSARY

Hedge, Hedging: The use of derivative commodity and interest-rate instruments to reduce financial exposure to commodity-price and interest-rate volatility.

Master Limited Partnership (MLP): A limited partnership business that is publicly traded on an exchange, such as the New York Stock Exchange. MLPs have one or more general partners that manage the business and assume its legal debts and obligations.

Natural Gas Liquids (NGL): Liquid hydrocarbons that are extracted and separated from the natural gas stream. NGL products include ethane, ethane/propane mix, propane, iso-butane, butane and natural gasoline.

Partnership Units: The ownership interests owned by partners – the investors – in a partnership; similar to owning shares of stock in a corporation.

Risk: Exposure to commodity-price, interest-rate and throughput volatility, as well as disruptions in the operations of the company's assets.

Units of Measure:
Mcf = Thousand cubic feet
Bbls = Barrels (42 U.S. gallons)
MMcf = Million cubic feet
MBbls = Thousand barrels
Bcf = Billion cubic feet
MGal = Thousand gallons
MMBtu = Million British thermal units
BBtu = Billion British thermal units
GPM = Gallons of NGLs per thousand cubic feet of natural gas
bpd = Barrels per day

CORPORATE INFORMATION

ONEOK Partners is a publicly traded master limited partnership engaged in the natural gas gathering and processing, natural gas pipelines and natural gas liquids 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), a diversified energy company founded in 1906 that's involved in natural gas distribution and energy services.

ONEOK owns 43.4 percent of the partnership.

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 are generally 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 related to the cash received.

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. Any unitholder receiving a duplicate copy of such 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
Moody's Investors Service	Baa2

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

Investor Relations
Andrew Ziola, *vice president – investor relations and communications*, by phone at 918-588-7163 or by email at andrew.ziola@oneok.com.

T.D. Eureste, *manager – investor relations*, by phone at 918-588-7167 or by email at teureste@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 earnings before interest, taxes, depreciation and amortization (EBITDA) and distributable cash flow (DCF) amounts that are non-GAAP financial measures. EBITDA and DCF are used as measures of the partnership's financial performance. EBITDA is defined as net income adjusted for interest expense, depreciation and amortization, income taxes and allowance for equity funds used during construction. DCF is defined as 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. The partnership believes the non-GAAP financial measures described above are useful to investors because these measurements are used by many companies in its industry as a measurement of 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. EBITDA and DCF 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 for a given period nor do they equate to available cash as defined in 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, 2012, included in this annual report.

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