ONEOK INC /NEW/
Form 10-Q
May 02, 2018
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

X Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended March 31, 2018.
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 001-13643

ONEOK, Inc.
(Exact name of registrant as specified in its charter)

Oklahoma	73-1520922
(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

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 whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer X	Accelerated filer __	Non-accelerated filer __
Smaller reporting company__	Emerging growth company__	

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.__

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

On April 23, 2018, the Company had 411,076,188 shares of common stock outstanding.

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ONEOK, Inc.

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As used in this Quarterly Report, references to “we,” “our” or “us” refer to ONEOK, Inc., an Oklahoma corporation, and its predecessors, divisions, and subsidiaries, unless the context indicates otherwise.

The statements in this Quarterly 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,” “pla “believe,” “should,” “goal,” “forecast,” “guidance,” “could,” “may,” “continue,” “might,” “potential,” “scheduled” and other w 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 2, Management's Discussion and Analysis of Financial Condition and Results of Operations “Forward-Looking Statements,” in this Quarterly Report and under Part I, Item 1A, “Risk Factors,” in our Annual Report.

INFORMATION AVAILABLE ON OUR WEBSITE

We make available, free of charge, on our website (www.oneok.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, Corporate Governance Guidelines, Director Independence Guidelines, Bylaws and the written charter of our Audit Committee are also available on our website, and we will provide copies of these documents upon request.

In addition to our filings with the SEC and materials posted on our website, we also use Twitter®, LinkedIn® and Facebook® as additional channels of distribution to reach public investors. Information contained on our website, posted on our social media accounts, and any corresponding applications, 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.

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GLOSSARY

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

$2.5 Billion Credit Agreement	ONEOK's $2.5 billion revolving credit agreement, effective June 30, 2017
AFUDC	Allowance for funds used during construction
Annual Report	Annual Report on Form 10-K for the year ended December 31, 2017
ASU	Accounting Standards Update
Bbl	Barrels, 1 barrel is equivalent to 42 United States gallons
BBtu/d	Billion British thermal units per day
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
CFTC	U.S. Commodity Futures Trading Commission
Clean Air Act	Federal Clean Air Act, as amended
DJ	Denver-Julesburg
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
FERC	Federal Energy Regulatory Commission
GAAP	Accounting principles generally accepted in the United States of America
Intermediate Partnership	ONEOK Partners Intermediate Limited Partnership, a wholly owned subsidiary of ONEOK Partners, L.P.
LIBOR	London Interbank Offered Rate
MBbl/d	Thousand barrels per day
MDth/d	Thousand dekatherms per day
Merger Transaction	The transaction, effective June 30, 2017, in which ONEOK acquired all of ONEOK Partners' outstanding common units not already directly or indirectly owned by ONEOK
MMBbl	Million barrels
MMBtu	Million British thermal units
MMcf/d	Million cubic feet per day
Moody's	Moody's Investors Service, Inc.
Natural Gas Act	Natural Gas Act of 1938, as amended
NGL(s)	Natural gas liquid(s)
NGL products	Marketable natural gas liquid purity products, such as ethane, ethane/propane mix, propane, iso-butane, normal butane and natural gasoline
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
ONEOK	ONEOK, Inc.
ONEOK Partners	ONEOK Partners, L.P.
OPIS	Oil Price Information Service
PHMSA	United States Department of Transportation Pipeline and Hazardous Materials Safety Administration
POP	Percent of Proceeds
Quarterly Report(s)	Quarterly Report(s) on Form 10-Q
Roadrunner	Roadrunner Gas Transmission, LLC, a 50 percent-owned joint venture
S&P	S&P Global Ratings
SCOOP	South Central Oklahoma Oil Province, an area in the Anadarko Basin in Oklahoma
SEC	Securities and Exchange Commission
	Series E Non-Voting, Perpetual Preferred Stock, par value $0.01 per share

Series E Preferred Stock	
STACK	Sooner Trend Anadarko Canadian Kingfisher, an area in the Anadarko Basin in Oklahoma
Tax Cuts and Jobs Act	H.R. 1, the tax reform bill, signed into law on December 22, 2017

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Term Loan Agreement	ONEOK Partners’ senior unsecured three-year $1.0 billion term loan agreement dated January 8, 2016, as amended
Topic 606	Accounting Standards Update 2014-09, “Revenue from Contracts with Customers”
West Texas LPG	West Texas LPG Pipeline Limited Partnership and Mesquite Pipeline
WTI	West Texas Intermediate
WTLPG	West Texas LPG Pipeline Limited Partnership, an 80 percent-owned joint venture
XBRL	eXtensible Business Reporting Language

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PART I - FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

ONEOK Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended March 31,	
(Unaudited)	2018	2017
	(Thousands of dollars, except per share amounts)	
Revenues		
Commodity sales	$2,820,004	$2,216,717
Services	282,073	532,894
Total revenues	3,102,077	2,749,611
Cost of sales and fuel (exclusive of items shown separately below)	2,368,026	2,143,843
Operations and maintenance	181,181	162,052
Depreciation and amortization	104,237	99,419
General taxes	29,023	27,153
(Gain) loss on sale of assets	(89)	7
Operating income	419,699	317,137
Equity in net earnings from investments (Note I)	40,187	39,564
Allowance for equity funds used during construction	230	13
Other income	738	4,341
Other expense	(3,309)	(3,467)
Interest expense (net of capitalized interest of $2,038, and $1,441, respectively)	(115,725)	(116,462)
Income before income taxes	341,820	241,126
Income taxes	(75,771)	(54,941)
Net income	266,049	186,185
Less: Net income attributable to noncontrolling interests	1,541	98,824
Net income attributable to ONEOK	264,508	87,361
Less: Preferred stock dividends	275	—
Net income available to common shareholders	$264,233	$87,361
Basic earnings per common share	$0.65	$0.41
Diluted earnings per common share	$0.64	$0.41
Average shares (thousands)		
Basic	409,676	211,619
Diluted	412,173	213,602
Dividends declared per share of common stock	$0.77	$0.615

See accompanying Notes to Consolidated Financial Statements.

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ONEOK, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Unaudited)	Three Months Ended March 31, 2018	2017
	(Thousands of dollars)	
Net income	$266,049	$186,185
Other comprehensive income (loss), net of tax		
Unrealized gains (losses) on derivatives, net of tax of $(10,312) and $(4,401), respectively	34,524	24,456
Realized (gains) losses on derivatives recognized in net income, net of tax of $(3,578) and $(3,365), respectively	11,976	17,283
Change in pension and postretirement benefit plan liability, net of tax of $(781) and $(1,360), respectively	2,615	2,041
Other comprehensive income (loss) on investments in unconsolidated affiliates, net of tax of $(844) and $(58), respectively	2,824	325
Total other comprehensive income (loss), net of tax	51,939	44,105
Comprehensive income	317,988	230,290
Less: Comprehensive income attributable to noncontrolling interests	1,541	127,641
Comprehensive income attributable to ONEOK	$316,447	$102,649

See accompanying Notes to Consolidated Financial Statements.

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ONEOK, Inc. and Subsidiaries
CONSOLIDATED BALANCE SHEETS

	March 31,	December 31,
(Unaudited)	2018	2017
Assets	(Thousands of dollars)	
Current assets		
Cash and cash equivalents	$17,474	$37,193
Accounts receivable, net	844,218	1,202,951
Materials and supplies	98,695	90,301
Natural gas and natural gas liquids in storage	185,298	342,293
Commodity imbalances	38,993	38,712
Other current assets	106,067	53,008
Total current assets	1,290,745	1,764,458
Property, plant and equipment		
Property, plant and equipment	15,838,443	15,559,667
Accumulated depreciation and amortization	2,960,254	2,861,541
Net property, plant and equipment	12,878,189	12,698,126
Investments and other assets		
Investments in unconsolidated affiliates	997,380	1,003,156
Goodwill and intangible assets	990,485	993,460
Deferred income taxes	116,120	205,907
Other assets	159,428	180,830
Total investments and other assets	2,263,413	2,383,353
Total assets	$16,432,347	$16,845,937

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ONEOK, Inc. and Subsidiaries
CONSOLIDATED BALANCE SHEETS
(Continued)

(Unaudited)	March 31, 2018	December 31, 2017
Liabilities and equity	(Thousands of dollars)	
Current liabilities		
Current maturities of long-term debt (Note D)	$932,650	$432,650
Short-term borrowings (Note D)	—	614,673
Accounts payable	773,054	1,140,571
Commodity imbalances	124,687	164,161
Accrued interest	97,525	135,309
Other current liabilities	122,922	179,971
Total current liabilities	2,050,838	2,667,335
Long-term debt, excluding current maturities (Note D)	7,091,751	8,091,629
Deferred credits and other liabilities		
Deferred income taxes	53,805	52,697
Other deferred credits	366,701	348,924
Total deferred credits and other liabilities	420,506	401,621
Commitments and contingencies (Note J)		
Equity (Note E)		
ONEOK shareholders' equity:		
Preferred stock, $0.01 par value: issued 20,000 shares at March 31, 2018 and December 31, 2017	—	—
Common stock, $0.01 par value: authorized 1,200,000,000 shares, issued 445,016,234 shares and outstanding 411,073,529 shares at March 31, 2018; issued 423,166,234 shares and outstanding 388,703,543 shares at December 31, 2017	4,450	4,232
Paid-in capital	7,735,173	6,588,878
Accumulated other comprehensive loss (Note F)	(174,692)	(188,530)
Retained earnings	—	—
Treasury stock, at cost: 33,942,705 shares at March 31, 2018, and 34,462,691 shares at December 31, 2017	(863,485)	(876,713)
Total ONEOK shareholders' equity	6,701,446	5,527,867
Noncontrolling interests in consolidated subsidiaries	167,806	157,485
Total equity	6,869,252	5,685,352
Total liabilities and equity	$16,432,347	$16,845,937

See accompanying Notes to Consolidated Financial Statements.

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ONEOK, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)	Three Months Ended March 31, 2018	2017
	(Thousands of dollars)	
Operating activities		
Net income	$266,049	$186,185
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	104,237	99,419
Equity in net earnings from investments	(40,187)	(39,564)
Distributions received from unconsolidated affiliates	41,095	39,520
Deferred income taxes	74,890	53,397
Share-based compensation expense	7,203	5,907
Pension and postretirement benefit expense, net of contributions	(8,393)	(5,018)
Allowance for equity funds used during construction	(230)	(13)
(Gain) loss on sale of assets	(89)	7
Changes in assets and liabilities:		
Accounts receivable	358,733	137,586
Natural gas and natural gas liquids in storage	149,825	(53,305)
Accounts payable	(361,008)	(122,843)
Commodity imbalances, net	(39,755)	1,888
Settlement of exit activities liabilities	(1,580)	(4,119)
Accrued interest	(37,784)	(22,363)
Risk-management assets and liabilities	34,387	45,977
Other assets and liabilities, net	(52,072)	(53,571)
Cash provided by operating activities	495,321	269,090
Investing activities		
Capital expenditures (less allowance for equity funds used during construction)	(264,467)	(112,737)
Contributions to unconsolidated affiliates	(147)	(4,422)
Distributions received from unconsolidated affiliates in excess of cumulative earnings	8,721	7,400
Proceeds from sale of assets	241	296
Cash used in investing activities	(255,652)	(109,463)
Financing activities		
Dividends paid	(316,408)	(129,842)
Distributions to noncontrolling interests	(1,500)	(136,680)
Borrowing (repayment) of short-term borrowings, net	(614,673)	180,452
Repayment of long-term debt	(501,913)	(1,951)
Issuance of common stock	1,182,117	3,722
Other, net	(7,011)	(13,395)
Cash used in financing activities	(259,388)	(97,694)
Change in cash and cash equivalents	(19,719)	61,933
Cash and cash equivalents at beginning of period	37,193	248,875
Cash and cash equivalents at end of period	$17,474	$310,808

See accompanying Notes to Consolidated Financial Statements.

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ONEOK, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(Unaudited)	ONEOK Shareholders' Equity Common Stock Issued	Preferred Stock Issued	Common Stock	Preferred Stock	Paid-in Capital
	(Shares)		(Thousands of dollars)		
January 1, 2018	423,166,234	20,000	$4,232	$ —	$6,588,878
Cumulative effect adjustment for adoption of ASUs (Note A)	—	—	—	—	—
Net income	—	—	—	—	—
Other comprehensive income (loss) (Note F)	—	—	—	—	—
Common stock issued	21,850,000	—	218	—	1,169,247
Common stock dividends - $0.77 per share (Note E)	—	—	—	—	(11,960)
Preferred stock dividends (Note E)	—	—	—	—	(275)
Distributions to noncontrolling interests	—	—	—	—	—
Contributions from noncontrolling interests	—	—	—	—	—
Other	—	—	—	—	(10,717)
March 31, 2018	445,016,234	20,000	$4,450	$ —	$7,735,173

(Unaudited)	ONEOK Shareholders' Equity Common Stock Issued	Preferred Stock Issued	Common Stock	Preferred Stock	Paid-in Capital
	(Shares)		(Thousands of dollars)		
January 1, 2017	245,811,180	—	$2,458	$ —	$1,234,314
Cumulative effect adjustment for adoption of ASU 2016-09	—	—	—	—	—
Net income	—	—	—	—	—
Other comprehensive income (loss)	—	—	—	—	—
Common stock issued	—	—	—	—	(2,506)
Common stock dividends - $0.615 per share	—	—	—	—	—
Distributions to noncontrolling interests	—	—	—	—	—
Other	—	—	—	—	261
March 31, 2017	245,811,180	—	$2,458	$ —	$1,232,069

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ONEOK, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(Continued)

(Unaudited)	ONEOK Shareholders' Equity Accumulated Other Comprehensive Loss	Retained Earnings	Treasury Stock	Noncontrolling Interests in Consolidated Subsidiaries	Total Equity
	(Thousands of dollars)				
January 1, 2018	$(188,530)	$ —	$(876,713)	$ 157,485	$5,685,352
Cumulative effect adjustment for adoption of ASUs (Note A)	(38,101)	39,803	—	17	1,719
Net income	—	264,508	—	1,541	266,049
Other comprehensive income (loss) (Note F)	51,939	—	—	—	51,939
Common stock issued	—	—	13,228	—	1,182,693
Common stock dividends - $0.77 per share (Note E)	—	(304,311)	—	—	(316,271)
Preferred stock dividends (Note E)	—	—	—	—	(275)
Distributions to noncontrolling interests	—	—	—	(1,500)	(1,500)
Contributions from noncontrolling interests	—	—	—	10,263	10,263
Other	—	—	—	—	(10,717)
March 31, 2018	$(174,692)	$ —	$(863,485)	$ 167,806	$6,869,252

(Unaudited)	ONEOK Shareholders' Equity Accumulated Other Comprehensive Loss	Retained Earnings	Treasury Stock	Noncontrolling Interests in Consolidated Subsidiaries	Total Equity
	(Thousands of dollars)				
January 1, 2017	$(154,350)	$—	$(893,677)	$ 3,240,170	$3,428,915
Cumulative effect adjustment for adoption of ASU 2016-09	—	73,368	—	—	73,368
Net income	—	87,361	—	98,824	186,185
Other comprehensive income (loss)	15,288	—	—	28,817	44,105
Common stock issued	—	—	5,707	—	3,201
Common stock dividends - $0.615 per share	—	(129,842)	—	—	(129,842)
Distributions to noncontrolling interests	—	—	—	(136,680)	(136,680)
Other	—	—	—	—	261
March 31, 2017	$(139,062)	$30,887	$(887,970)	$ 3,231,131	$3,469,513

See accompanying Notes to Consolidated Financial Statements.

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ONEOK, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Our accompanying unaudited consolidated financial statements have been prepared pursuant to the rules and regulations of the SEC. These statements have been prepared in accordance with GAAP and reflect all adjustments that, in our opinion, are necessary for a fair statement of the results for the interim periods presented. All such adjustments are of a normal recurring nature. The 2017 year-end Consolidated Balance Sheet data was derived from our audited financial statements but does not include all disclosures required by GAAP. Certain reclassifications have been made in the prior-year financial statements to conform to the current year presentation. These unaudited consolidated financial statements should be read in conjunction with our audited consolidated financial statements in our Annual Report.

Merger Transaction - On June 30, 2017, we completed the acquisition of all of the outstanding common units of ONEOK Partners that we did not already own at a fixed exchange ratio of 0.985 of a share of our common stock for each ONEOK Partners common unit. We issued 168.9 million shares of our common stock to third-party common unitholders of ONEOK Partners in exchange for all of the 171.5 million outstanding common units of ONEOK Partners that we previously did not own. As a result of the completion of the Merger Transaction, common units of ONEOK Partners are no longer publicly traded.

Prior to June 30, 2017, we and our subsidiaries owned all of the general partner interest, which included incentive distribution rights, and a portion of the limited partner interest, which together represented a 41.2 percent ownership interest in ONEOK Partners. The earnings of ONEOK Partners that are attributed to its units held by the public until June 30, 2017, are reported as “Net income attributable to noncontrolling interest” in our accompanying Consolidated Statements of Income. Our general partner incentive distribution rights effectively terminated at the closing of the Merger Transaction.

Our significant accounting policies are consistent with those disclosed in Note A of the Notes to Consolidated Financial Statements in our Annual Report, except as described below for accounting standards adopted this quarter.

Recently Issued Accounting Standards Update - Changes to GAAP are established by the Financial Accounting Standards Board (FASB) in the form of ASUs to the FASB Accounting Standards Codification. We consider the applicability and impact of all ASUs. ASUs not listed below were assessed and determined to be either not applicable or clarifications of ASUs listed below. We also exclude ASUs not yet adopted that were disclosed in our Annual Report to not materially impact us. The following tables provide a brief description of recent accounting pronouncements and our analysis of the effects on our financial statements:

Standard	Description	Date of Adoption	Effect on the Financial Statements or Other Significant Matters
Standards that were adopted			
ASU 2014-09, “Revenue from Contracts with Customers (Topic 606)”	The standard outlines the principles an entity must apply to measure and recognize revenue for entities that enter into contracts to provide goods or services to their customers. The core principle is that an entity should recognize revenue at an amount that reflects the consideration to which the entity expects to be entitled in exchange	First quarter 2018	We adopted this standard on January 1, 2018, using the modified retrospective method. We recognized the cumulative effect of adopting the new revenue standard as an increase to beginning retained earnings of $1.7 million. Results for reporting periods beginning after January 1, 2018, are presented under the new standard, while prior periods are not adjusted and continue to be reported under the accounting standards in effect

for transferring goods or services to a customer. The amendment also requires more extensive disaggregated revenue disclosures in interim and annual financial statements.	for those periods. The adoption of Topic 606 was not material to our net income; however, a significant portion of amounts historically presented as services revenues are now presented as a reduction to cost of sales and fuel. See Note K for discussion of these changes and additional disclosures.

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Standard	Description	Date of Adoption	Effect on the Financial Statements or Other Significant Matters
Standards that were adopted (continued)			
ASU 2016-01, “Financial Instruments-Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities”	The standard requires all equity investments, other than those accounted for using the equity method of accounting or those that result in consolidation of the investee, to be measured at fair value with changes in fair value recognized in net income, eliminates the available-for-sale classification for equity securities with readily determinable fair values and eliminates the cost method for equity investments without readily determinable fair values.	First quarter 2018	We do not have any equity investments classified as available-for-sale or accounted for using the cost method, therefore, the impact of adopting of this standard was not material.
ASU 2016-15, “Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments”	The standard clarifies the classification of certain cash receipts and cash payments on the statement of cash flows where diversity in practice has been identified.	First quarter 2018	The impact of adopting this standard was not material.
ASU 2017-07, “Compensation - Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost”	The standard requires the service cost component of net benefit cost to be reported in the same line item or items as other compensation costs from services rendered by the pertinent employees during the period. The other components of net benefit cost are required to be presented in the income statement separately from the service cost component and outside a subtotal of income from operations.	First quarter 2018	We adopted this standard on January 1, 2018, and utilized the practical expedient to estimate the impact on the prior comparative period information presented. Immaterial reclassifications have been made to prior comparative period information to reflect the current period presentation. Prior to adoption, we expensed all components of the net periodic benefit costs for our pension and postretirement benefit plans in operations and maintenance expense. We now record only the service component of the net periodic benefit costs in operations and maintenance expense, with the remainder being recorded in other expense. There was no change to net income from the adoption of this standard.
ASU 2017-12, “Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities	The standard more closely aligns hedge accounting with companies’ existing risk-management strategies by expanding the strategies eligible for hedge accounting, relaxing the timing	First quarter 2018	We adopted this standard in the first quarter 2018 and recorded an immaterial cumulative-effect adjustment to the opening balance of retained earnings and other comprehensive income to eliminate the separate measurement of hedge

	requirements of hedge documentation and effectiveness assessments, permitting in certain cases, the use of qualitative assessments on an ongoing basis to assess hedge effectiveness, and requiring new disclosures and presentation.		ineffectiveness. See Note C for changes to disclosures due to adopting this standard.
ASU 2018-02, “Income Statement - Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income”	This standard allows a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the Tax Cuts and Jobs Act.	First quarter 2018	We adopted this standard in the first quarter 2018 and recorded a $38.1 million adjustment to retained earnings and accumulated other comprehensive income to eliminate the stranded tax effects resulting from the Tax Cuts and Jobs Act.

Standard	Description	Date of Adoption	Effect on the Financial Statements or Other Significant Matters
Standards that are not yet adopted			
ASU 2016-02, "Leases (Topic 842)"	The standard requires the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases under previous GAAP. It also requires qualitative disclosures along with specific quantitative disclosures by lessees and lessors to meet the objective of enabling users of financial statements to assess the amount, timing and uncertainty of cash flows arising from leases.	First quarter 2019	We are evaluating our current leases and other contracts that may be considered leases under the new standard and the impact on our internal controls, accounting policies and financial statements and disclosures. Our evaluation process includes creating a database of our existing leases and identifying a central group to track and account for lease activity, which is ongoing. We are developing internal controls to ensure the completeness and accuracy of the data. Due to this ongoing work, we cannot yet determine the quantitative impact, but adoption of the standard will result in the recognition of right of use assets and lease liabilities not previously recorded that will be presented on our Consolidated Balance Sheet under Topic 842 and will require disclosure in our footnotes. We are also monitoring recent exposure drafts and clarifications issued by the FASB.

B. FAIR VALUE MEASUREMENTS

Determining Fair Value - We define fair value as the price that would be received from the sale of an asset or the transfer of a liability in an orderly transaction between market participants at the measurement date. We use market and income approaches to determine the fair value of our assets and liabilities and consider the markets in which the transactions are executed. We measure the fair value of a group of financial assets and liabilities consistent with how a market participant would price the net risk exposure at the measurement date.

While many of the contracts in our derivative portfolio are executed in liquid markets where price transparency exists, some contracts are executed in markets for which market prices may exist, but the market may be relatively inactive. This results in limited price transparency that requires management's judgment and assumptions to estimate fair values. For certain transactions, we utilize modeling techniques using NYMEX-settled pricing data and implied forward LIBOR curves. Inputs into our fair value estimates include commodity-exchange prices, over-the-counter quotes, historical correlations of pricing data, data obtained from third-party pricing services and LIBOR and other liquid money-market instrument rates. We validate our valuation inputs with third-party information and settlement prices from other sources, where available.

In addition, as prescribed by the income approach, we compute the fair value of our derivative portfolio by discounting the projected future cash flows from our derivative assets and liabilities to present value using interest-rate yields to calculate present-value discount factors derived from LIBOR, Eurodollar futures and the LIBOR interest-rate swaps market. We also take into consideration the potential impact on market prices of liquidating positions in an orderly manner over a reasonable period of time under current market conditions. We consider current market data in evaluating counterparties', as well as our own, nonperformance risk, net of collateral, by using specific and sector bond yields and monitoring the credit default swap markets. Although we use our best estimates to determine the fair value of the derivative contracts we have executed, the ultimate market prices realized could differ from our estimates, and the differences could be material.

The fair value of our forward-starting interest-rate swaps are determined using financial models that incorporate the implied forward LIBOR yield curve for the same period as the future interest-rate swap settlements.

Fair Value Hierarchy - At each balance sheet date, we utilize a fair value hierarchy to classify fair value amounts recognized or disclosed in our financial statements based on the observability of inputs used to estimate such fair value. The levels of the hierarchy are described below:

- Level 1 - fair value measurements are based on unadjusted quoted prices for identical securities in active markets, including NYMEX-settled prices. These balances are comprised predominantly of exchange-traded derivative contracts for natural gas and crude oil.
- Level 2 - fair value measurements are based on significant observable pricing inputs, such as NYMEX-settled prices for natural gas and crude oil, and financial models that utilize implied forward LIBOR yield curves for interest-rate swaps.
- Level 3 - fair value measurements are based on inputs that may include one or more unobservable inputs, including internally developed natural gas basis and NGL price curves that incorporate observable and unobservable market data

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from broker quotes, third-party pricing services, market volatilities derived from the most recent NYMEX close spot prices and forward LIBOR curves, and adjustments for the credit risk of our counterparties. We corroborate the data on which our fair value estimates are based using our market knowledge of recent transactions, analysis of historical correlations and validation with independent broker quotes. These balances categorized as Level 3 are composed of derivatives for natural gas and NGLs. We do not believe that our Level 3 fair value estimates have a material impact on our results of operations, as the majority of our derivatives are accounted for as hedges.

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.

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

	March 31, 2018					
	Level 1	Level 2	Level 3	Total - Gross	Netting (a)	Total - Net
	(Thousands of dollars)					
Derivative assets						
Commodity contracts						
Financial contracts	$3,180	$—	$20,065	$23,245	$(23,245)	$—
Physical contracts	—	—	40	40	—	40
Interest-rate contracts	—	83,513	—	83,513	—	83,513
Total derivative assets	$3,180	$83,513	$20,105	$106,798	$(23,245)	$83,553
Derivative liabilities						
Commodity contracts						
Financial contracts	$(8,121)	$—	$(15,799)	$(23,920)	$23,920	$—
Physical contracts	—	—	(1,208)	(1,208)	—	(1,208)
Interest-rate contracts	—	(11,169)	—	(11,169)	—	(11,169)
Total derivative liabilities	$(8,121)	$(11,169)	$(17,007)	$(36,297)	$23,920	$(12,377)

(a) - Derivative assets and liabilities are presented in our Consolidated Balance Sheets on a net basis. We net derivative assets and liabilities when a legally enforceable master-netting arrangement exists between the counterparty to a derivative contract and us. At March 31, 2018, we held no cash and posted $18.5 million of cash with various counterparties, including $0.7 million of cash collateral that is offsetting derivative net liability positions under master-netting arrangements in the table above. The remaining $17.8 million of cash collateral in excess of derivative net liability positions is included in other current assets in our Consolidated Balance Sheets.

	December 31, 2017					
	Level 1	Level 2	Level 3	Total - Gross	Netting (a)	Total - Net
	(Thousands of dollars)					
Derivative assets						
Commodity contracts						
Financial contracts	$4,252	$—	$20,203	$24,455	$(24,455)	$—
Interest rate contracts	—	49,960	—	49,960	—	49,960
Total derivative assets	$4,252	$49,960	$20,203	$74,415	$(24,455)	$49,960
Derivative liabilities						
Commodity contracts						
Financial contracts	$(5,708)	$—	$(48,260)	$(53,968)	$53,936	$(32)

Physical contracts	—	—	(4,781)	(4,781)	—	(4,781)
Total derivative liabilities	$(5,708)	$—	$(53,041)	$(58,749)	$53,936	$(4,813)

(a) - Derivative assets and liabilities are presented in our Consolidated Balance Sheets on a net basis. We net derivative assets and liabilities when a legally enforceable master-netting arrangement exists between the counterparty to a derivative contract and us. At December 31, 2017, we held no cash and posted $49.7 million of cash with various counterparties, including $29.5 million of cash collateral that is offsetting derivative net liability positions under master-netting arrangements in the table above. The remaining $20.2 million of cash collateral in excess of derivative net liability positions is included in other current assets in our Consolidated Balance Sheets.

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The following table sets forth a reconciliation of our Level 3 fair value measurements for the periods indicated:

Derivative Assets (Liabilities)	Three Months Ended March 31, 2018	2017
	(Thousands of dollars)	
Net assets (liabilities) at beginning of period	$(32,838)	$(23,319)
Total realized/unrealized gains (losses):		
Included in earnings (a)	(85)	913
Included in other comprehensive income (loss)	36,021	21,634
Net assets (liabilities) at end of period	$3,098	$(772)

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

Realized/unrealized gains (losses) include the realization of our derivative contracts through maturity. During the three months ended March 31, 2018 and 2017, gains or losses included in earnings attributable to the change in unrealized gains or losses relating to assets and liabilities still held at the end of each reporting period were not material.

We recognize transfers into and out of the levels in the fair value hierarchy as of the end of each reporting period. During the three months ended March 31, 2018 and 2017, there were no transfers between levels.

Other Financial Instruments - The approximate fair value of cash and cash equivalents, accounts receivable, accounts payable and short-term borrowings is equal to book value due to the short-term nature of these items. Our cash and cash equivalents are composed of bank and money market accounts and are classified as Level 1. Our short-term borrowings are classified as Level 2 since the estimated fair value of the short-term borrowings can be determined using information available in the commercial paper market.

The estimated fair value of our consolidated long-term debt, including current maturities, was $8.7 billion and $9.3 billion at March 31, 2018, and December 31, 2017, respectively. The book value of our consolidated long-term debt, including current maturities, was $8.0 billion and $8.5 billion at March 31, 2018, and December 31, 2017, respectively. The estimated fair value of the aggregate of our and ONEOK Partners’ senior notes outstanding was determined using quoted market prices for similar issues with similar terms and maturities. The estimated fair value of our consolidated 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 are also subject to the risk of interest-rate fluctuation in the normal course of business. We use physical-forward purchases and sales and financial derivatives to secure a certain price for a portion of our natural gas, condensate and NGL products; to reduce our exposure to commodity price and interest-rate fluctuations; and to achieve more predictable cash flows. We follow established policies and procedures to assess risk and approve, monitor and report our risk-management activities. We have not used these instruments for trading purposes.

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 reduce the near-term commodity price risk associated with a portion of the forecasted sales of these commodities:

- Futures contracts - Standardized contracts to purchase or sell natural gas and crude oil for future delivery or settlement under the provisions of exchange regulations;

- Forward contracts - Nonstandardized commitments between two parties to purchase or sell natural gas, crude oil or NGLs for future physical delivery. These contracts are typically nontransferable and can only be canceled with the consent of both parties;
- Swaps - Exchange of one or more payments based on the value of one or more commodities. These instruments transfer the financial risk associated with a future change in value between the counterparties of the transaction, without also conveying ownership interest in the asset or liability; and
- Options - Contractual agreements that give the holder the right, but not the obligation, to buy or sell a fixed quantity of a commodity at a fixed price within a specified period of time. Options may either be standardized and exchange-traded or customized and nonexchange-traded.

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We may also use other instruments including collars to mitigate commodity price risk. A collar is a combination of a purchased put option and a sold call option, which places a floor and a ceiling price for commodity sales being hedged.

In our Natural Gas Gathering and Processing segment, we are exposed to commodity price risk as a result of retaining a portion of the commodity sales proceeds associated with our POP with fee contracts. Under certain POP with fee contracts, our fees and POP percentage may increase or decrease if production volumes, delivery pressures or commodity prices change relative to specified thresholds. We also are exposed to basis risk between the various production and market locations where we buy and sell commodities. As part of our hedging strategy, we use the previously described commodity derivative financial instruments and physical-forward contracts to reduce the impact of price fluctuations related to natural gas, NGLs and condensate.

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

In our Natural Gas Pipelines segment, we are exposed to commodity price risk because our intrastate and interstate natural gas pipelines retain natural gas from our customers for operations or as part of our fee for services provided. When the amount of natural gas consumed in operations by these pipelines differs from the amount provided by our customers, our pipelines must buy or sell natural gas, or store or use natural gas from inventory, which can expose this segment 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 may use physical-forward sales or purchases to reduce the impact of price fluctuations related to natural gas. At March 31, 2018, and December 31, 2017, there were no financial derivative instruments with respect to our natural gas pipeline operations.

Interest-rate risk - We manage interest-rate risk through the use of fixed-rate debt, floating-rate debt and interest-rate swaps. Interest-rate swaps are agreements to exchange interest payments at some future point based on specified notional amounts. In January 2018, we settled the remaining $500 million of our interest-rate swaps used to hedge our LIBOR-based interest payments. In March 2018, we entered into forward-starting interest-rate swaps with notional amounts totaling $750 million to hedge the variability of interest payments on a portion of our forecasted debt issuances that may result from changes in the benchmark interest rate before the debt is issued.

At March 31, 2018, and December 31, 2017, we had forward-starting interest-rate swaps with notional amounts totaling $2.0 billion and $1.3 billion, respectively, to hedge the variability of interest payments on a portion of our forecasted debt issuances. At December 31, 2017, we had interest-rate swaps with a notional amount totaling $500 million to hedge the variability of our LIBOR-based interest payments. All of our interest-rate swaps are designated as cash flow hedges.

Accounting Treatment - Our accounting treatment of derivative instruments is consistent with that disclosed in Note A of the Notes to Consolidated Financial Statements in our Annual Report, updated for the adoption of ASU 2017-12.

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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 presented on a gross basis for the periods indicated:

	Location in our Consolidated Balance Sheets	March 31, 2018 Assets	March 31, 2018 (Liabilities)	December 31, 2017 Assets	December 31, 2017 (Liabilities)
		(Thousands of dollars)			
Derivatives designated as hedging instruments					
Commodity contracts					
Financial contracts	Other current assets/other current liabilities	$16,719	$(19,764)	$16,978	$(42,819)
	Other assets/other deferred credits	3,061	(747)	—	(3,838)
Physical contracts	Other current assets/other current liabilities	40	(1,208)	—	(4,781)
Interest-rate contracts	Other current assets	59,502	—	1,330	—
	Other assets/other deferred credits	24,011	(11,169)	48,630	—
Total derivatives designated as hedging instruments		103,333	(32,888)	66,938	(51,438)
Derivatives not designated as hedging instruments					
Commodity contracts					
Financial contracts	Other current assets/other current liabilities	3,465	(3,409)	7,477	(7,311)
Total derivatives not designated as hedging instruments		3,465	(3,409)	7,477	(7,311)
Total derivatives		$106,798	$(36,297)	$74,415	$(58,749)

Notional Quantities for Derivative Instruments - The following table sets forth the notional quantities for derivative instruments held for the periods indicated:

	Contract Type	March 31, 2018 Purchased/ Payor	March 31, 2018 Sold/ Receiver	December 31, 2017 Purchased/ Payor	December 31, 2017 Sold/ Receiver
Derivatives designated as hedging instruments:					
Cash flow hedges					
Fixed price					
- Natural gas (Bcf)	Futures and swaps	—	(18.5)	—	(24.5)
- Crude oil and NGLs (MMBbl)	Futures, forwards and swaps	3.5	(10.7)	3.5	(11.1)
Basis					
- Natural gas (Bcf)	Futures and swaps	—	(18.5)	—	(24.5)
Interest-rate contracts (Millions of dollars)	Swaps	$2,000.0	$ —	$1,750.0	$ —
Derivatives not designated as hedging instruments:					
Fixed price					
- NGLs (MMBbl)	Futures, forwards and swaps	0.5	(0.5)	0.8	(0.8)

These notional amounts are used to summarize the volume of financial instruments; however, they do not reflect the extent to which the positions offset one another and, consequently, do not reflect our actual exposure to market or credit risk.

Cash Flow Hedges - At March 31, 2018, our Consolidated Balance Sheet reflected a net loss of $174.7 million in accumulated other comprehensive loss. The portion of accumulated other comprehensive loss attributable to our commodity derivative financial instruments is an unrealized loss of $1.4 million, net of tax, which is expected to be realized within the next two years as the forecasted transactions affect earnings. If commodity prices remain at current levels, we will realize approximately $3.2 million in net losses, net of tax, over the next 12 months and approximately

$1.8 million in net gains, net of tax, thereafter. The amount deferred in accumulated other comprehensive loss attributable to our settled interest-rate swaps is a loss of $104.0

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million, net of tax, which will be recognized over the life of the long-term, fixed-rate debt, including losses of $17.5 million, net of tax, that will be reclassified into earnings during the next 12 months as the hedged items affect earnings. The remaining amounts in accumulated other comprehensive loss are attributable primarily to our pension and postretirement benefit plan obligations, which are expected to be amortized over the average remaining service period of employees participating in these plans.

The following table sets forth the unrealized effect of cash flow hedges recognized in other comprehensive income (loss) for the periods indicated:

Derivatives in Cash Flow Hedging Relationships	Three Months Ended March 31, 2018	2017
	(Thousands of dollars)	
Commodity contracts	$20,925	$27,328
Interest-rate contracts	23,911	1,529
Total unrealized gain (loss) recognized in other comprehensive income (loss) on derivatives	$44,836	$28,857

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

Derivatives in Cash Flow Hedging Relationships	Location of Gain (Loss) Reclassified from Accumulated Other Comprehensive Loss into Net Income	Three Months Ended March 31, 2018	2017
		(Thousands of dollars)	
Commodity contracts	Commodity sales revenues	$(11,611)	$(15,319)
Interest-rate contracts	Interest expense	(3,943)	(5,329)
Total gain (loss) reclassified from accumulated other comprehensive loss into net income on derivatives		$(15,554)	$(20,648)

Credit Risk - We monitor the creditworthiness of our counterparties and compliance with policies and limits established by our Risk Oversight and Strategy Committee. We maintain credit policies with regard to our counterparties that we believe minimize overall credit risk. These policies include an evaluation of potential counterparties’ financial condition (including credit ratings, bond yields and credit default swap rates), collateral requirements under certain circumstances and the use of standardized master-netting agreements that allow us to net the positive and negative exposures associated with a single counterparty. We have counterparties whose credit is not rated, and for those customers, we use internally developed credit ratings.

From time to time, we may enter into financial derivative instruments that contain provisions that require us to maintain an investment-grade credit rating from S&P and/or Moody’s. If our credit ratings on our senior unsecured long-term debt were to decline below investment grade, the counterparties to the derivative instruments could request collateralization on derivative instruments in net liability positions. There were no financial derivative instruments with contingent features related to credit risk at March 31, 2018.

The counterparties to our derivative contracts typically consist of major energy companies, financial institutions and commercial and industrial end users. This concentration of counterparties may affect our overall exposure to credit risk, either positively or negatively, in that the counterparties may be affected similarly by changes in economic, regulatory or other conditions. Based on our policies, exposures, credit and other reserves, we do not anticipate a material adverse effect on our financial position or results of operations as a result of counterparty nonperformance.

At March 31, 2018, the credit exposure from our derivative assets is with investment-grade companies in the financial services sector.

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D. DEBT

The following table sets forth our consolidated debt for the periods indicated:

	March 31, 2018	December 31, 2017
	(Thousands of dollars)	
ONEOK		
Commercial paper outstanding, bearing a weighted-average interest rate of 2.23% as of December 31, 2017	$—	$614,673
Senior unsecured obligations:		
$700,000 at 4.25% due February 2022	547,397	547,397
$500,000 at 7.5% due September 2023	500,000	500,000
$500,000 at 4.0% due July 2027	500,000	500,000
$100,000 at 6.875% due September 2028	100,000	100,000
$400,000 at 6.0% due June 2035	400,000	400,000
$700,000 at 4.95% due July 2047	700,000	700,000
ONEOK Partners		
Senior unsecured obligations:		
$425,000 at 3.2% due September 2018	425,000	425,000
$1,000,000 term loan, rate of 2.87% as of December 31, 2017, due January 2019	—	500,000
$500,000 at 8.625% due March 2019	500,000	500,000
$300,000 at 3.8% due March 2020	300,000	300,000
$900,000 at 3.375 % due October 2022	900,000	900,000
$425,000 at 5.0 % due September 2023	425,000	425,000
$500,000 at 4.9 % due March 2025	500,000	500,000
$600,000 at 6.65% due October 2036	600,000	600,000
$600,000 at 6.85% due October 2037	600,000	600,000
$650,000 at 6.125% due February 2041	650,000	650,000
$400,000 at 6.2% due September 2043	400,000	400,000
Guardian Pipeline		
Weighted average 7.85% due December 2022	34,695	36,607
Total debt	8,082,092	9,198,677
Unamortized portion of terminated swaps	18,038	18,468
Unamortized debt issuance costs and discounts	(75,729)	(78,193)
Current maturities of long-term debt	(932,650)	(432,650)
Short-term borrowings (a)	—	(614,673)
Long-term debt	$7,091,751	$8,091,629

(a) - Individual issuances of commercial paper under our commercial paper program generally mature in 90 days or less. These issuances are supported by and reduce the borrowing capacity under our $2.5 Billion Credit Agreement.

$2.5 Billion Credit Agreement - Our $2.5 Billion Credit Agreement is a $2.5 billion revolving credit facility and 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 $2.5 Billion Credit Agreement, adjusted for all noncash charges and increased for projected EBITDA from certain lender-approved capital expansion projects) of no more than 5.5 to 1 at March 31, 2018, and for the subsequent quarter and 5.0 to 1 thereafter. Once the covenant decreases to 5.0 to 1, if we consummate one or more acquisitions in which the aggregate purchase is $25 million or more, the allowable ratio of indebtedness to adjusted EBITDA will increase to 5.5 to 1 for the quarter in which the acquisition is completed and the two following quarters.

Our $2.5 Billion Credit Agreement includes a $100 million sublimit for the issuance of standby letters of credit and a $200 million sublimit for swingline loans. Under the terms of our $2.5 Billion Credit Agreement, we may request an increase in the size of the facility to an aggregate of $3.5 billion by either commitments from new lenders or increased commitments from existing lenders. Our $2.5 Billion Credit Agreement contains provisions for an applicable margin rate and an annual facility fee, both of which adjust with changes in our credit ratings. Based on our current credit ratings, borrowings, if any, will accrue at LIBOR plus 110 basis points, and the annual facility fee is 15 basis points. We have the option to request two one-year extensions, subject to lender approval, which may be used for working capital, capital expenditures, acquisitions and mergers, the issuance of letters of credit and for other general corporate purposes. At March 31, 2018, we had no borrowings outstanding, our ratio of indebtedness to adjusted EBITDA was 3.7 to 1, and we were in compliance with all covenants under our $2.5 Billion Credit Agreement.

Repayments - In January 2018, we repaid the remaining $500 million balance outstanding on the Term Loan Agreement due 2019 with a combination of cash on hand and short-term borrowings.

Debt Guarantees - Effective June 30, 2017, with the Merger Transaction, we, ONEOK Partners and the Intermediate Partnership issued, to the extent not already in place, guarantees of the indebtedness of ONEOK and ONEOK Partners.

E. EQUITY

Ownership Interest in ONEOK Partners - As a result of the Merger Transaction in 2017, we and our subsidiaries owned 100 percent of ONEOK Partners at March 31, 2018, and December 31, 2017. At March 31, 2018, the caption “Noncontrolling interests” on our Consolidated Balance Sheet reflects only the 20 percent of WTLPG that we do not own.

Equity Issuances - In January 2018, we completed an underwritten public offering of 21.9 million shares of our common stock at a public offering price of $54.50 per share, generating net proceeds of $1.2 billion. We used the net proceeds from this offering to fund capital expenditures and for general corporate purposes, which included repaying a portion of our outstanding indebtedness.

In July 2017, we established an “at-the-market” equity program for the offer and sale from time to time of our common stock up to an aggregate amount of $1 billion. The program allows us to offer and sell our common stock at prices we deem appropriate through a sales agent. Sales of our common stock may 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 stock under the program. During the three months ended March 31, 2018, no shares were sold through our “at-the-market” equity program.

During the year ended December 31, 2017, we sold 8.4 million shares of common stock through our “at-the-market” equity program that resulted in net proceeds of $448.3 million. The net proceeds from these issuances were used for general corporate purposes, including repayment of outstanding indebtedness and to fund capital expenditures.

Dividends - Holders of our common stock share equally in any dividend declared by our board of directors, subject to the rights of the holders of outstanding preferred stock. Dividends paid on our common stock in February 2018 were $0.77 per share. A dividend of $0.795 per share was declared for shareholders of record at the close of business on April 30, 2018, payable May 15, 2018.

The Series E Preferred Stock pays quarterly dividends on each share of Series E Preferred Stock, when, as and if declared by our Board of Directors, at a rate of 5.5 percent per year. We paid dividends for the Series E Preferred Stock of $0.6 million in 2017 and $0.3 million in February 2018. Dividends totaling $0.3 million were declared for the Series E Preferred Stock and are payable May 15, 2018.

Cash Distributions - Prior to the consummation of the Merger Transaction, we received distributions from ONEOK Partners on our common and Class B units and our 2 percent general partner interest, which included our incentive distribution rights.

As a result of the Merger Transaction in 2017, we are entitled to receive all available ONEOK Partners cash. Our incentive distribution rights effectively terminated at the close of the Merger Transaction.

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The following table sets forth ONEOK Partners’ distributions paid during the period prior to the closing of the Merger Transaction:

	Three Months Ended March 31, 2017
	(Thousands, except per unit amounts)
Distribution per unit	$ 0.79
General partner distributions	$ 6,660
Incentive distributions	100,538
Distributions to general partner	107,198
Limited partner distributions to ONEOK	90,323
Limited partner distributions to other unitholders	135,480
Total distributions paid	$ 333,001

F. ACCUMULATED OTHER COMPREHENSIVE LOSS

The following table sets forth the balance in accumulated other comprehensive loss for the period indicated:

	Unrealized Gains (Losses) on Risk-Management Assets/Liabilities (a)	Pension and Postretirement Benefit Plan Obligations (a) (b)	Unrealized Gains (Losses) on Risk-Management Assets/Liabilities of Unconsolidated Affiliates (a)	Accumulated Other Comprehensive Loss (a)
	(Thousands of dollars)			
January 1, 2018	$ (81,915)	$ (105,411)	$ (1,204)	$ (188,530)
Other comprehensive income (loss) before reclassifications	34,524	(601)	2,860	36,783
Amounts reclassified from accumulated other comprehensive loss	11,976	3,216	(36)	15,156
Net current-period other comprehensive income (loss) attributable to ONEOK	46,500	2,615	2,824	51,939
Impact of adoption of ASU 2018-02 (c)	(17,935)	(20,166)	—	(38,101)
March 31, 2018	$ (53,350)	$ (122,962)	$ 1,620	$ (174,692)

(a) - All amounts are presented net of tax.
(b) - Includes amounts related to supplemental executive retirement plan.
(c) - We elected to adopt this guidance in the first quarter 2018, which allows a reclassification from accumulated other comprehensive income/loss to retained earnings for the stranded tax effects resulting from the Tax Cuts and Jobs Act. After adopting and applying this guidance, our accumulated other comprehensive loss balance at March 31, 2018, does not include stranded taxes resulting from the Tax Cuts and Jobs Act.

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The following table sets forth the effect of reclassifications from accumulated other comprehensive loss in our Consolidated Statements of Income for the periods indicated:

Details about Accumulated Other Comprehensive Loss Components	Three Months Ended March 31, 2018	2017	Affected Line Item in the Consolidated Statements of Income
	(Thousands of dollars)		
Unrealized gains (losses) on risk-management assets/liabilities			
Commodity contracts	$(11,611)	$(15,319)	Commodity sales revenues
Interest-rate contracts	(3,943)	(5,329)	Interest expense
	(15,554)	(20,648)	Income before income taxes
	3,578	3,365	Income tax expense
	(11,976)	(17,283)	Net income
Noncontrolling interests	—	(11,625)	Less: Net income attributable to noncontrolling interests
	$(11,976)	$(5,658)	Net income attributable to ONEOK
Pension and postretirement benefit plan obligations (a)			
Amortization of net loss	$(4,592)	$(3,812)	Other income (expense)
Amortization of unrecognized prior service credit	415	415	Other income (expense)
	(4,177)	(3,397)	Income before income taxes
	961	1,359	Income tax expense
	$(3,216)	$(2,038)	Net income attributable to ONEOK
Unrealized gains (losses) on risk-management assets/liabilities of unconsolidated affiliates			
	$47	$(96)	Equity in net earnings from investments
	(11)	15	Income tax expense
	36	(81)	Net income
Noncontrolling interests	—	(56)	Less: Net income attributable to noncontrolling interests
	$36	$(25)	Net income attributable to ONEOK
Total reclassifications for the period attributable to ONEOK	$(15,156)	$(7,721)	Net income attributable to ONEOK

(a) - These components of accumulated other comprehensive loss are included in the computation of net periodic benefit cost. See Note H for additional detail of our net periodic benefit cost.

G. EARNINGS PER SHARE

The following tables set forth the computation of basic and diluted EPS for the periods indicated:

	Three Months Ended March 31, 2018		
	Income	Shares	Per Share Amount

	(Thousands, except per share amounts)		
Basic EPS			
Net income attributable to ONEOK available for common stock	$264,233	409,676	$ 0.65
Diluted EPS			
Effect of dilutive securities	—	2,497	
Net income attributable to ONEOK available for common stock and common stock equivalents	$264,233	412,173	$ 0.64

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	Three Months Ended March 31, 2017		
	Income	Shares	Per Share Amount
	(Thousands, except per share amounts)		
Basic EPS			
Net income attributable to ONEOK available for common stock	$87,361	211,619	$ 0.41
Diluted EPS			
Effect of dilutive securities	—	1,983	
Net income attributable to ONEOK available for common stock and common stock equivalents	$87,361	213,602	$ 0.41

H. EMPLOYEE BENEFIT PLANS

The following tables set forth the components of net periodic benefit cost for our pension and postretirement benefit plans for the periods indicated:

	Pension Benefits		Postretirement Benefits	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2018	2017	2018	2017
	(Thousands of dollars)			
Components of net periodic benefit cost				
Service cost	$1,832	$1,722	$211	$165
Interest cost	4,408	4,655	527	565
Expected return on plan assets	(5,969)	(5,336)	(672)	(564)
Amortization of prior service credit	—	—	(415)	(415)
Amortization of net loss	4,258	3,392	334	420
Net periodic benefit cost (income)	$4,529	$4,433	$(15)	$171

I. UNCONSOLIDATED AFFILIATES

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

	Three Months Ended March 31,	
	2018	2017
	(Thousands of dollars)	
Northern Border Pipeline	$17,137	$18,817
Overland Pass Pipeline Company	16,387	13,566
Roadrunner Gas Transmission	4,958	4,405
Other	1,705	2,776
Equity in net earnings from investments	$40,187	$39,564

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

	Three Months Ended March 31,	
	2018	2017
	(Thousands of dollars)	
Income Statement		
Operating revenues	$158,908	$154,280
Operating expenses	$68,401	$66,936
Net income	$84,480	$81,131
Distributions paid to us	$49,816	$46,920

We incurred expenses in transactions with unconsolidated affiliates of $37.5 million and $36.7 million for the three months ended March 31, 2018 and 2017, respectively, primarily related to Overland Pass Pipeline Company and Northern Border Pipeline. Accounts payable to our equity-method investees at March 31, 2018, and December 31, 2017, were $12.8 million and $13.6 million, respectively. Accounts receivable from our equity-method investees were $7.4 million at March 31, 2018, and were not material at December 31, 2017.

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.

Northern Border Pipeline entered into a settlement with shippers that was approved by the FERC in February 2018. The settlement provides for tiered rate reductions beginning January 1, 2018, that will reduce rates 12.5 percent by January 2020 compared with previous rates and requires new rates to be established by January 2024. We do not expect the resulting decrease in equity earnings and cash distributions from Northern Border Pipeline to be material to us.

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

Roadrunner Gas Transmission - The Roadrunner limited liability company agreement provides that distributions to members are made on a pro rata basis according to each member's ownership interest. As the operator, we have been delegated the authority to determine such distributions in accordance with, and on the frequency set forth in, the Roadrunner limited liability company agreement. Cash distributions are equal to 100 percent of available cash, as defined in the limited liability company agreement. During the three months ended March 31, 2017, we made contributions of $4 million to Roadrunner. We made no contributions to Roadrunner during the three months ended

March 31, 2018.

We have an operating agreement with Roadrunner that provides for reimbursement or payment to us for management services and certain operating costs. Reimbursements and payments from Roadrunner included in operating income in our Consolidated Statements of Income for the three months ended March 31, 2018 and 2017, were not material.

J. COMMITMENTS AND CONTINGENCIES

Environmental Matters and Pipeline Safety - The operation of pipelines, plants and other facilities for the gathering, processing, transportation and storage of natural gas, NGLs, condensate and other products is subject to numerous and complex laws and regulations pertaining to health, safety and the environment. As an owner and/or operator of these facilities, we must comply with United States laws and regulations at the federal, state, local and tribal levels that relate to air and water quality, hazardous and solid waste management and disposal, cultural resource protection and other environmental matters. The cost of planning, designing, constructing and operating pipelines, plants and other facilities must incorporate compliance with these laws and regulations and safety standards. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and potentially criminal enforcement measures, including citizen suits, which can include the assessment of monetary penalties, the imposition of remedial requirements and the issuance of injunctions or restrictions on operation or construction. Management believes that, based on currently known information, compliance with these laws and regulations will not have a material adverse effect on our results of operations, financial condition or cash flows.

Regulatory - The Tax Cuts and Jobs Act makes extensive changes to the U.S. tax laws and includes provisions that reduce the U.S. corporate tax rate to 21 percent from 35 percent, increase expensing for capital investment, and limit the interest deduction and use of net operating losses to offset future taxable income. The Tax Cuts and Jobs Act may reduce future tariff rates charged on our regulated pipelines. The rates charged to our customers have generally been established through shipper specific negotiation, discounts and negotiated settlements, which do not ascribe any specific cost of service elements. We expect future tariff rate changes, if any, related to the change in the U.S. corporate tax rate to be established prospectively over time on a similar negotiated basis. We will continue to monitor applicable FERC rule-making, including the March 2018 notice of proposed rule-making on the impact of the Tax Cuts and Jobs Act on FERC-regulated rates for natural gas pipelines, which is subject to a public comment process prior to being finalized. If in the future the FERC or other regulatory bodies were to require us to establish a regulatory liability for amounts previously collected on our regulated pipelines, then we would expect to record a regulatory liability through a one-time charge to expense.

We also continue to monitor the FERC’s March 2018 revised policy statement for master limited partnerships, which no longer allows interstate natural gas and oil pipelines owned by master limited partnerships to recover an income tax allowance in cost of service rates. This revised policy remains pending at the FERC based on various requests for reconsideration or rehearing. We do not expect this FERC action to be material to our results of operations, as we are organized as a C-corporation. Further, regardless of organizational structure, we do not expect this FERC action to materially affect us, as the rates charged to our customers have generally been established through shipper specific negotiation, discounts and negotiated settlements, which do not ascribe any specific cost of service elements.

The FERC allows regulated NGL pipelines an annual index adjustment to transportation rates, which is intended to allow recovery of changes in costs without a complicated cost of service filing. The FERC is expected to evaluate how best to incorporate the effects of new tax policies in its next calculation of the rate index in 2020, for indexing effective July 2021. We do not expect to be materially impacted by any such change in the index calculation, as our regulated NGL pipeline revenues are primarily under negotiated agreements.

Legal Proceedings - Gas Index Pricing Litigation - As previously reported, in March 2017, the United States District Court for the District of Nevada (the Court) granted summary judgment to OESC in Sinclair Oil Corporation v. ONEOK Energy Services Company, L.P. (filed in the United States District Court for the District of Wyoming in September 2005, transferred to MDL-1566 in the Court). In September 2017, the Court entered a final judgment in favor of OESC in Sinclair, which was appealed by Sinclair Oil Corporation to the Ninth Circuit Court of Appeals. We expect that future charges, if any, from the ultimate resolution of the Sinclair case will not be material to our results of operations, financial position or cash flows.

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

K. REVENUES

Adoption of ASC Topic 606: Revenue from Contracts with Customers - We adopted Topic 606 on January 1, 2018, using the modified retrospective method applied to those contracts, which were active as of January 1, 2018. Results for reporting periods beginning after January 1, 2018, are presented under Topic 606, while prior periods are not adjusted and continue to be reported under the accounting standards in effect for those periods. We recorded a net increase to the beginning balance of retained earnings of approximately $1.7 million as of January 1, 2018, due to the cumulative impact of adopting the standard, primarily related to the timing of revenue on transportation contracts with tiered rates that resulted in contract assets in our Natural Gas Pipelines segment, contributions in aid of construction from customers that resulted in contract liabilities and an adjustment to NGL inventory related to contractual fees in our Natural Gas Liquids Segment, as described below.

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Based on the new guidance, we determined that certain Natural Gas Gathering and Processing segment POP with fee contracts and Natural Gas Liquids segment exchange services contracts that include the purchase of commodities are supplier contracts. Therefore, contractual fees in these identified contracts are now recorded as a reduction to cost of sales and fuel pursuant to ASC 705 rather than as services revenue. To the extent we hold inventory related to these purchases, the related fees previously recorded in services revenue will not be recognized until the inventory is sold. We continue to be principal on the downstream sales of those commodities, which is unchanged from our assessment under previous guidance.

The impact on our Consolidated Income Statement and Balance Sheet is as follows (in thousands):

	Three Months Ended March 31, 2018		
Income Statement	As Reported	Balance Without Adoption of Topic 606	Effect of Change Increase/(Decrease)
Services revenue	$282,073	$634,315	$ (352,242)
Cost of sales and fuel (exclusive of depreciation and operating costs)	$2,368,026	$2,725,774	$ (357,748)
Depreciation and amortization	$104,237	$104,092	$ 145
Income taxes	$75,771	$74,539	$ 1,232
Net income	$266,049	$261,920	$ 4,129
Net income attributable to noncontrolling interests	$1,541	$1,539	$ 2
Net income attributable to ONEOK	$264,508	$260,381	$ 4,127

	March 31, 2018		
Balance Sheet	As Reported	Balance Without Adoption of Topic 606	Effect of Change Increase/(Decrease)
Natural gas and natural gas liquids in storage	$185,298	$186,998	$ (1,700)
Other current assets	$106,067	$105,097	$ 970
Property, plant and equipment	$15,838,443	$15,816,674	$ 21,769
Accumulated depreciation and amortization	$2,960,254	$2,958,737	$ 1,517
Deferred income taxes	$116,120	$117,854	$ (1,734)
Other assets	$159,428	$154,167	$ 5,261
Other current liabilities	$122,922	$120,877	$ 2,045
Other deferred credits	$366,701	$351,525	$ 15,176
Retained earnings/paid-in capital	$7,735,173	$7,729,364	$ 5,809
Noncontrolling interests in consolidated subsidiaries	$167,806	$167,787	$ 19

Revenue Recognition - Revenues are recognized when control of the promised goods or services is transferred to our customers in an amount that reflects the consideration we expect to be entitled to receive in exchange for those goods or services. Our payment terms vary by customer and contract type, including requiring payment before products or services are delivered to certain customers. However, the term between customer prepayments, completion of our performance obligations, invoicing and receipt of payment due is not significant.

Practical Expedients - We do not disclose the value of unsatisfied performance obligations for (i) contracts with an original expected length of one year or less and (ii) variable consideration on contracts for which we recognize revenue at the amount to which we have the right to invoice for services performed.

Receivables from Customers, Performance Obligations and Revenue Sources - The balances in accounts receivable on our Consolidated Balance Sheet at March 31, 2018, and December 31, 2017, include customer receivables of $832.1 million and $1.2 billion, respectively. Revenues sources are disaggregated in Note L and are derived from commodity sales and services revenues, as described below:

Commodity Sales (all segments) - We contract to deliver residue natural gas, condensate, unfractionated NGLs and/or NGL products to customers at a specified delivery point. Our sales agreements may be daily or longer-term contracts for a specified volume. We consider the sale and delivery of each unit of a commodity an individual performance obligation as the customer is expected to control, accept and benefit from each unit individually. We record revenue when the commodity is delivered to the customer as this represents the point in time when control of the product is transferred to the customer. Revenue is recorded based on the contracted selling price, which is generally index-based and settled monthly.

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Services

Gathering only contracts (Natural Gas Gathering and Processing segment) - Under this type of contract, we charge fees for providing midstream services, which include gathering our customer’s natural gas. Our performance obligation begins with delivery of raw natural gas to our system. This service is treated as one performance obligation that is satisfied over time. We use the output method based on delivery of product to our system as the measure of progress, as our services are performed simultaneously.

POP contracts with producer take-in-kind rights (Natural Gas Gathering and Processing segment) - Under this type of contract, we do not control the stream of unprocessed gas that we receive at the wellhead due to the producer’s take-in-kind rights. We charge fees for providing midstream services, which include gathering and processing our customer’s natural gas. After performing these services, we return a portion of the natural gas to the producer and purchase the remaining commodities. Our performance obligation begins with delivery of raw natural gas to our system. This service is treated as one performance obligation that is satisfied over time. We use the output method based on delivery of product to our system as the measure of progress, as our services are performed simultaneously.

Transportation and exchange contracts (Natural Gas Liquids segment) - Under this type of contract, we charge fees for providing midstream services, which may include a bundled combination of gathering, transporting and/or fractionation of our customer’s NGLs. Our performance obligation begins with delivery of unfractionated NGLs or NGL products to our system. These services represent a series of distinct services that are treated as one performance obligation that is satisfied over time. We use the output method based on delivery of product to our system as the measure of progress, as our services are performed simultaneously. For transportation services under a tariff on our NGL transportation pipelines, fees are recorded upon redelivery to our customer at the completion of the transportation services.

Storage contracts (Natural Gas Liquids and Natural Gas Pipelines segments) - We reserve a stated storage capacity and inject/withdraw/store commodities for our customer. The capacity reservation and injection/withdrawal/storage services are considered a bundled service, as we integrate them into one stand-ready obligation provided on a daily basis over the life of the agreement and satisfied over time. Fixed capacity reservation fees are allocated and evenly recognized in revenue. Capacity reservation fees that vary based on a stated or implied economic index and correspond with the costs to provide our services are recognized in revenue based on daily effective fee rate. Transportation, injection and withdrawal fees are recognized in revenue as those services are provided and are dependent on the volume transported, injected or withdrawn by our customer, which is at our customer’s discretion. We use the output method based on the passage of time to measure satisfaction of the performance obligation associated with our daily stand-ready services.

Firm service transportation contracts (Natural Gas Pipelines segment) - We reserve a stated transportation capacity and transport commodities for our customer. The capacity reservation and transportation services are considered a bundled service, as we integrate them into one stand-ready obligation provided on a daily basis over the life of the agreement and satisfied over time. Fixed capacity reservation fees are allocated and evenly recognized in revenue. Capacity reservation fees that vary based on a stated or implied economic index and correspond with the costs to provide our services are recognized in revenue based on a daily effective fee rate. If the capacity reservation fees vary solely as a contract feature, contract assets or liabilities are recorded for the difference between the amount recorded in revenue and the amount billed to the customer. Transportation fees are recognized in revenue as those services are provided and are dependent on the volume transported by our customer, which is at our customer’s discretion. We use the output method based on the passage of time to measure satisfaction of the performance obligation associated with our daily stand-ready services.

Interruptible transportation contracts (Natural Gas Pipelines segment) - We agree to transport natural gas on our pipelines between the customer’s specified nomination and delivery points if capacity is available after satisfying firm transportation service obligations. Our performance obligations and those of our customer begin with delivery of natural gas onto our pipeline and is satisfied over time. The transaction price is based on the transportation fees times the volumes transported. These fees may change over time based on an index or other factors provided in the agreement. We use the output method based on delivery of product to the customer to measure satisfaction of the performance obligation. The total consideration for delivered volumes is recorded in revenue at the time of delivery, when the customer obtains control.

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Contract Assets and Contract Liabilities - Contract assets and contract liabilities are recorded when the amount of revenue recognized from a contract with a customer differs from the amount billed to the customer and recorded in accounts receivable. Our contract asset balances at the beginning and end of the period primarily relate to our firm service transportation contracts with tiered rates and were approximately $6.2 million and $6.4 million as of March 31, 2018, and January 1, 2018, respectively. At March 31, 2018, contract assets of $1.0 million and $5.2 million, are included in other current assets and other assets, respectively, in our Consolidated Balance Sheet. There have been no additions to our contract asset balance in 2018. Our contract liabilities primarily represent deferred revenue on NGL storage contracts for which revenue is recognized over a one-year term and deferred revenue on contributions in aid of construction received from customers for which revenue is recognized over the contract period, which averages approximately 10 years.

Contract Liability	(Millions of dollars)
Balance at January 1, 2018 (a)	$ 33.3
Revenue recognized included in beginning balance	(17.3)
Net additions	5.2
Balance at March 31, 2018 (b)	$ 21.2

(a) - Balance includes $19.5 million of current liabilities.
(b) - Contract liabilities of $6.0 million and $15.2 million are included in other current liabilities and other deferred credits, respectively, in our Consolidated Balance Sheet.

Transaction Price Allocated to Unsatisfied Performance Obligations - The following table presents aggregate value allocated to unsatisfied performance obligations as of March 31, 2018, and the amounts we expect to recognize in revenue in future periods, related primarily to firm transportation and storage contracts with remaining contract terms ranging from one month to 26 years:

Expected Period of Recognition in Revenue	(Millions of dollars)
Remainder of 2018	$242.9
2019	247.3
2020	215.4
2021	209.7
2022 and beyond	1,032.6
Total estimated transaction price allocated to unsatisfied performance obligations	$1,947.9

The table above excludes variable consideration allocated entirely to wholly unsatisfied performance obligations, wholly unsatisfied promises to transfer distinct goods or services that are part of a single performance obligation and consideration we determine to be fully constrained. Information on the nature of the variable consideration excluded and the nature of the performance obligations to which the variable consideration relates can be found in the description of the major contract types discussed above. The amounts we determined to be fully constrained relate to future sales obligations under long-term sales contracts where the transaction price is not known and minimum volume agreements, which we consider to be fully constrained until invoiced.

L. SEGMENTS

Segment Descriptions - Our operations are divided into three reportable business segments, as follows:

- our Natural Gas Gathering and Processing segment gathers, treats and processes natural gas;
- our Natural Gas Liquids segment gathers, treats, fractionates and transports NGLs and stores, markets and distributes NGL products; and

- our Natural Gas Pipelines segment operates regulated interstate and intrastate natural gas transmission pipelines and natural gas storage facilities.

Other and eliminations consist of corporate costs, the operating and leasing activities of our headquarters building and related parking facility and eliminations necessary to reconcile our reportable segments to our Consolidated Financial Statements.

Accounting Policies - The accounting policies of the segments are described in Note A of the Notes to Consolidated Financial Statements in our Annual Report, updated as described in Note A of this Quarterly Report. Our chief operating decision-maker reviews the financial performance of each of our three segments, as well as our financial performance as a whole, on a regular basis. Adjusted EBITDA by segment is utilized in this evaluation. We believe this financial measure is useful to investors because it and similar measures are used by many companies in our industry as a measurement of financial performance and are commonly employed by financial analysts and others to evaluate our financial performance and to compare financial

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performance among companies in our industry. Adjusted EBITDA for each segment is defined as net income adjusted for interest expense, depreciation and amortization, noncash impairment charges, income taxes, allowance for equity funds used during construction, noncash compensation and other noncash items. This calculation may not be comparable with similarly titled measures of other companies.

Customers - Our Natural Gas Gathering and Processing segment derives services revenue primarily from crude oil and natural gas producers, which include both large integrated and independent exploration and production companies. The downstream commodity sales customers of our Natural Gas Gathering and Processing segment are primarily utilities, large industrial companies, marketing companies and our NGL affiliate. Our Natural Gas Liquids segment's customers are primarily NGL and natural gas gathering and processing companies; large integrated and independent crude oil and natural gas production companies; propane distributors; ethanol producers; and petrochemical, refining and NGL marketing companies. Our Natural Gas Pipelines segment's customers are primarily local natural gas distribution companies, electric-generation companies, large industrial companies, municipalities, producers and marketing companies.

For the three months ended March 31, 2018 and 2017, we had no single customer from which we received 10 percent or more of our consolidated revenues.

Operating Segment Information - The following tables set forth certain selected financial information for our operating segments for the periods indicated:

Three Months Ended March 31, 2018	Natural Gas Gathering and Processing	Natural Gas Liquids (a)	Natural Gas Pipelines (b)	Total
	(Thousands of dollars)			
NGL and condensate sales	$413,157	$2,552,770	$—	$2,965,927
Residue natural gas sales	254,997	—	4,919	259,916
Gathering, processing and exchange services revenue	38,429	83,258	—	121,687
Transportation and storage revenue	—	53,478	98,338	151,816
Other	1,408	2,963	6,654	11,025
Total revenues (c)	707,991	2,692,469	109,911	3,510,371
Cost of sales and fuel (exclusive of depreciation and operating costs)	(492,622)	(2,281,072)	(5,454)	(2,779,148)
Operating costs	(88,359)	(88,592)	(33,190)	(210,141)
Equity in net earnings from investments	1,668	16,424	22,095	40,187
Other	1,873	2,850	263	4,986
Segment adjusted EBITDA	$130,551	$342,079	$93,625	$566,255
Depreciation and amortization	$(47,748)	$(42,427)	$(13,269)	$(103,444)
Total assets	$5,462,305	$8,370,364	$2,060,700	$15,893,369
Capital expenditures	$111,729	$124,921	$19,898	$256,548

(a) - Our Natural Gas Liquids segment has regulated and nonregulated operations. Our Natural Gas Liquids segment's regulated operations had revenues of $300.0 million, of which $253.4 million related to sales within the segment and cost of sales and fuel of $122.8 million.
(b) - Our Natural Gas Pipelines segment has regulated and nonregulated operations. Our Natural Gas Pipelines segment's regulated operations had revenues of $68.0 million and cost of sales and fuel of $9.1 million.
(c) - Intersegment revenues for the Natural Gas Gathering and Processing, Natural Gas Liquids and Natural Gas Pipelines segments totaled $397.8 million, $9.0 million and $2.1 million respectively.

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Three Months Ended March 31, 2018	Total Segments	Other and Eliminations	Total
	(Thousands of dollars)		
Reconciliations of total segments to consolidated			
NGL and condensate sales	$2,965,927	$(408,910)	$2,557,017
Residue natural gas sales	259,916	2,250	262,166
Gathering, processing and exchange services revenue	121,687	(21)	121,666
Transportation and storage revenue	151,816	(2,094)	149,722
Other	11,025	481	11,506
Total revenues (a)	$3,510,371	$(408,294)	$3,102,077
Cost of sales and fuel (exclusive of depreciation and operating costs)	$(2,779,148)	$411,122	$(2,368,026)
Operating costs	$(210,141)	$(63)	$(210,204)
Depreciation and amortization	$(103,444)	$(793)	$(104,237)
Equity in net earnings from investments	$40,187	$—	$40,187
Total assets	$15,893,369	$538,978	$16,432,347
Capital expenditures	$256,548	$7,919	$264,467

(a) - Noncustomer revenue for the three months ended March 31, 2018, totaled $(9.0) million related primarily to losses reclassified from accumulated other comprehensive income from derivatives on commodity contracts.

Three Months Ended March 31, 2017	Natural Gas Gathering and Processing	Natural Gas Liquids (a)	Natural Gas Pipelines (b)	Total
	(Thousands of dollars)			
Sales to unaffiliated customers	$400,149	$2,244,000	$104,924	$2,749,073
Intersegment revenues	261,127	147,984	1,894	411,005
Total revenues	661,276	2,391,984	106,818	3,160,078
Cost of sales and fuel (exclusive of depreciation and operating costs)	(488,384)	(2,048,693)	(16,603)	(2,553,680)
Operating costs	(71,328)	(78,440)	(31,563)	(181,331)
Equity in net earnings from investments	2,630	13,722	23,212	39,564
Other	(227)	(344)	1,094	523
Segment adjusted EBITDA	$103,967	$278,229	$82,958	$465,154
Depreciation and amortization	$(44,968)	$(41,115)	$(12,543)	$(98,626)
Total assets	$5,296,359	$8,194,835	$1,945,407	$15,436,601
Capital expenditures	$63,151	$20,453	$25,014	$108,618

(a) - Our Natural Gas Liquids segment has regulated and nonregulated operations. Our Natural Gas Liquids segment's regulated operations had revenues of $296.3 million, of which $252.9 million related to sales within the segment and cost of sales and fuel of $116.5 million.

(b) - Our Natural Gas Pipelines segment has regulated and nonregulated operations. Our Natural Gas Pipelines segment's regulated operations had revenues of $68.9 million and cost of sales and fuel of $14.1 million.

Three Months Ended March 31, 2017	Total Segments	Other and Eliminations	Total
	(Thousands of dollars)		
Reconciliations of total segments to consolidated			
Sales to unaffiliated customers	$2,749,073	$538	$2,749,611
Intersegment revenues	411,005	(411,005)	—
Total revenues	$3,160,078	$(410,467)	$2,749,611
Cost of sales and fuel (exclusive of depreciation and operating costs)	$(2,553,680)	$409,837	$(2,143,843)
Operating costs	$(181,331)	$(7,874)	$(189,205)
Depreciation and amortization	$(98,626)	$(793)	$(99,419)
Equity in net earnings from investments	$39,564	$—	$39,564
Total assets	$15,436,601	$630,957	$16,067,558
Capital expenditures	$108,618	$4,119	$112,737

	Three Months Ended March 31,	
	2018	2017
Reconciliation of net income to total segment adjusted EBITDA	(Thousands of dollars)	
Net income	$266,049	$186,185
Add:		
Interest expense, net of capitalized interest	115,725	116,462
Depreciation and amortization	104,237	99,419
Income taxes	75,771	54,941
Noncash compensation expense	9,226	1,647
Other corporate costs and noncash items	(4,753)	6,500
Total segment adjusted EBITDA	$566,255	$465,154

M. SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

ONEOK and ONEOK Partners are issuers of certain public debt securities. Effective with the Merger Transaction in 2017, we, ONEOK Partners and the Intermediate Partnership issued, to the extent not already in place, guarantees of the indebtedness of ONEOK and ONEOK Partners. The Intermediate Partnership holds all of ONEOK Partners' partnership interests and equity in its subsidiaries, as well as a 50 percent interest in Northern Border Pipeline. In lieu of providing separate financial statements for each subsidiary issuer and guarantor, we have included the accompanying condensed consolidating financial statements based on Rule 3-10 of the SEC's Regulation S-X. We have presented each of the parent and subsidiary issuers in separate columns in this single set of condensed consolidating financial statements.

For purposes of the following footnote:
- we are referred to as "Parent Issuer and Guarantor";
- ONEOK Partners is referred to as "Subsidiary Issuer and Guarantor";
- the Intermediate Partnership is referred to as "Guarantor Subsidiary"; and
- the "Non-Guarantor Subsidiaries" are all subsidiaries other than the Guarantor Subsidiary and Subsidiary Issuer and Guarantor.

The following unaudited supplemental condensed consolidating financial information is presented on an equity-method basis reflecting the separate accounts of ONEOK, ONEOK Partners and the Intermediate Partnership, the combined accounts of the Non-Guarantor Subsidiaries, the combined consolidating adjustments and eliminations, and our consolidated amounts for the periods indicated.

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Condensed Consolidating Statements of Income

(Unaudited)	Three Months Ended March 31, 2018 Parent Issuer & Guarantor	Subsidiary Issuer & Guarantor	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
	(Millions of dollars)					
Revenues						
Commodity sales	$—	$—	$—	$ 2,820.0	$—	$2,820.0
Services	—	—	—	282.6	(0.5)	282.1
Total revenues	—	—	—	3,102.6	(0.5)	3,102.1
Cost of sales and fuel (exclusive of items shown separately below)	—	—	—	2,368.0	—	2,368.0
Operating expenses	(0.7)	—	—	315.7	(0.5)	314.5
Gain on sale of assets	—	—	—	(0.1)	—	(0.1)
Operating income	0.7	—	—	419.0	—	419.7
Equity in net earnings from investments	368.5	370.9	370.9	28.6	(1,098.7)	40.2
Other income (expense), net	7.2	77.1	77.1	(9.6)	(154.2)	(2.4)
Interest expense, net	(39.8)	(77.1)	(77.1)	(75.9)	154.2	(115.7)
Income before income taxes	336.6	370.9	370.9	362.1	(1,098.7)	341.8
Income taxes	(72.1)	—	—	(3.7)	—	(75.8)
Net income	264.5	370.9	370.9	358.4	(1,098.7)	266.0
Less: Net income attributable to noncontrolling interests	—	—	—	1.5	—	1.5
Net income attributable to ONEOK	264.5	370.9	370.9	356.9	(1,098.7)	264.5
Less: Preferred stock dividends	0.3	—	—	—	—	0.3
Net income available to common shareholders	$264.2	$ 370.9	$ 370.9	$ 356.9	$ (1,098.7)	$264.2

(Unaudited)	Three Months Ended March 31, 2017 Parent Issuer & Guarantor	Subsidiary Issuer & Guarantor	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
	(Millions of dollars)					
Revenues						
Commodity sales	$—	$—	$—	$ 2,216.7	$—	$2,216.7
Services	—	—	—	532.9	—	532.9
Total revenues	—	—	—	2,749.6	—	2,749.6
Cost of sales and fuel (exclusive of items shown separately below)	—	—	—	2,143.8	—	2,143.8
Operating expenses	6.9	—	—	281.8	—	288.7
Operating income	(6.9)	—	—	324.0	—	317.1
Equity in net earnings from investments	268.7	269.1	269.1	20.7	(788.0)	39.6
Other income (expense), net	0.5	91.3	91.3	0.4	(182.6)	0.9
Interest expense, net	(25.8)	(91.3)	(91.3)	(90.7)	182.6	(116.5)
Income before income taxes	236.5	269.1	269.1	254.4	(788.0)	241.1
Income taxes	(51.2)	—	—	(3.7)	—	(54.9)
Net income	185.3	269.1	269.1	250.7	(788.0)	186.2
	97.9	—	—	0.9	—	98.8

Less: Net income attributable to noncontrolling interests						
Net income attributable to ONEOK	$87.4	$ 269.1	$ 269.1	$ 249.8	$ (788.0)	$87.4

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Condensed Consolidating Statements of Comprehensive Income

(Unaudited)	Three Months Ended March 31, 2018					
	Parent Issuer & Guarantor	Subsidiary Issuer & Guarantor	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
	(Millions of dollars)					
Net income	$264.5	$ 370.9	$ 370.9	$ 358.4	$ (1,098.7)	$266.0
Other comprehensive income (loss), net of tax						
Unrealized gains (losses) on derivatives, net of tax	18.4	20.9	20.9	16.1	(41.8)	34.5
Realized (gains) losses on derivatives in net income, net of tax	0.9	14.3	11.6	8.3	(23.1)	12.0
Change in pension and postretirement benefit plan liability, net of tax	3.2	(0.6)	—	—	—	2.6
Other comprehensive income (loss) on investments in unconsolidated affiliates, net of tax	—	3.7	3.7	2.8	(7.4)	2.8
Total other comprehensive income (loss), net of tax	22.5	38.3	36.2	27.2	(72.3)	51.9
Comprehensive income	287.0	409.2	407.1	385.6	(1,171.0)	317.9
Less: Comprehensive income attributable to noncontrolling interests	—	—	—	1.5	—	1.5
Comprehensive income attributable to ONEOK	$287.0	$ 409.2	$ 407.1	$ 384.1	$ (1,171.0)	$316.4

(Unaudited)	Three Months Ended March 31, 2017					
	Parent Issuer & Guarantor	Subsidiary Issuer & Guarantor	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
	(Millions of dollars)					
Net income	$185.3	$ 269.1	$ 269.1	$ 250.7	$ (788.0)	$186.2
Other comprehensive income (loss), net of tax						
Unrealized gains (losses) on derivatives, net of tax	—	28.8	27.3	51.8	(83.4)	24.5
Realized (gains) losses on derivatives in net income, net of tax	0.5	19.8	15.3	32.1	(50.4)	17.3
Change in pension and postretirement benefit plan liability, net of tax	2.0	—	—	—	—	2.0
Other comprehensive income (loss) on investments in unconsolidated affiliates, net of tax	—	0.4	0.4	0.7	(1.2)	0.3
Total other comprehensive income (loss), net of tax	2.5	49.0	43.0	84.6	(135.0)	44.1
Comprehensive income	187.8	318.1	312.1	335.3	(923.0)	230.3
Less: Comprehensive income attributable to noncontrolling interests	126.8	—	—	0.9	—	127.7
Comprehensive income attributable to ONEOK	$61.0	$ 318.1	$ 312.1	$ 334.4	$ (923.0)	$102.6

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Condensed Consolidating Balance Sheets

(Unaudited)	March 31, 2018 Parent Issuer & Guarantor	Subsidiary Issuer & Guarantor	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
Assets	(Millions of dollars)					
Current assets						
Cash and cash equivalents	$17.5	$—	$—	$ —	$—	$17.5
Accounts receivable, net	—	—	—	844.2	—	844.2
Natural gas and natural gas liquids in storage	—	—	—	185.3	—	185.3
Other current assets	70.8	—	—	172.9	—	243.7
Total current assets	88.3	—	—	1,202.4	—	1,290.7
Property, plant and equipment						
Property, plant and equipment	134.1	—	—	15,704.3	—	15,838.4
Accumulated depreciation and amortization	87.7	—	—	2,872.5	—	2,960.2
Net property, plant and equipment	46.4	—	—	12,831.8	—	12,878.2
Investments and other assets						
Investments	5,823.6	3,207.8	8,443.5	802.9	(17,280.4)	997.4
Intercompany notes receivable	3,450.2	8,118.3	2,882.6	—	(14,451.1)	—
Other assets	305.4	—	—	1,008.0	(47.4)	1,266.0
Total investments and other assets	9,579.2	11,326.1	11,326.1	1,810.9	(31,778.9)	2,263.4
Total assets	$9,713.9	$11,326.1	$11,326.1	$ 15,845.1	$(31,778.9)	$16,432.3
Liabilities and equity						
Current liabilities						
Current maturities of long-term debt	$—	$925.0	$—	$ 7.7	$—	$932.7
Accounts payable	6.3	—	—	766.8	—	773.1
Other current liabilities	43.5	68.2	—	233.3	—	345.0
Total current liabilities	49.8	993.2	—	1,007.8	—	2,050.8
Intercompany debt	—	—	8,118.3	6,332.8	(14,451.1)	—
Long-term debt, excluding current maturities	2,726.8	4,338.1	—	26.9	—	7,091.8
Deferred credits and other liabilities	235.8	—	—	232.0	(47.4)	420.4
Commitments and contingencies						
Equity						
Equity excluding noncontrolling interests in consolidated subsidiaries	6,701.5	5,994.8	3,207.8	8,077.8	(17,280.4)	6,701.5
Noncontrolling interests in consolidated subsidiaries	—	—	—	167.8	—	167.8
Total equity	6,701.5	5,994.8	3,207.8	8,245.6	(17,280.4)	6,869.3
Total liabilities and equity	$9,713.9	$11,326.1	$11,326.1	$ 15,845.1	$(31,778.9)	$16,432.3

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(Unaudited)	December 31, 2017 Parent Issuer & Guarantor	Subsidiary Issuer & Guarantor	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
Assets	(Millions of dollars)					
Current assets						
Cash and cash equivalents	$37.2	$—	$—	$ —	$—	$37.2
Accounts receivable, net	—	—	—	1,203.0	—	1,203.0
Materials and supplies	—	—	—	90.3	—	90.3
Natural gas and natural gas liquids in storage	—	—	—	342.3	—	342.3
Other current assets	9.8	1.3	—	80.6	—	91.7
Total current assets	47.0	1.3	—	1,716.2	—	1,764.5
Property, plant and equipment						
Property, plant and equipment	128.3	—	—	15,431.3	—	15,559.6
Accumulated depreciation and amortization	86.4	—	—	2,775.1	—	2,861.5
Net property, plant and equipment	41.9	—	—	12,656.2	—	12,698.1
Investments and other assets						
Investments	5,752.1	3,133.7	8,058.4	803.0	(16,744.0)	1,003.2
Intercompany notes receivable	2,926.9	8,627.8	3,703.1	—	(15,257.8)	—
Other assets	416.9	0.2	—	1,007.4	(44.4)	1,380.1
Total investments and other assets	9,095.9	11,761.7	11,761.5	1,810.4	(32,046.2)	2,383.3
Total assets	$9,184.8	$11,763.0	$11,761.5	$ 16,182.8	$(32,046.2)	$16,845.9
Liabilities and equity						
Current liabilities						
Current maturities of long-term debt	$—	$425.0	$—	$ 7.7	$—	$432.7
Short-term borrowings	614.7	—	—	—	—	614.7
Accounts payable	12.0	—	—	1,128.6	—	1,140.6
Other current liabilities	65.9	85.0	—	328.4	—	479.3
Total current liabilities	692.6	510.0	—	1,464.7	—	2,667.3
Intercompany debt	—	—	8,627.8	6,630.0	(15,257.8)	—
Long-term debt, excluding current maturities	2,726.4	5,336.4	—	28.8	—	8,091.6
Deferred credits and other liabilities	237.9	—	—	208.1	(44.4)	401.6
Commitments and contingencies						
Equity						
Equity excluding noncontrolling interests in consolidated subsidiaries	5,527.9	5,916.6	3,133.7	7,693.7	(16,744.0)	5,527.9
Noncontrolling interests in consolidated subsidiaries	—	—	—	157.5	—	157.5
Total equity	5,527.9	5,916.6	3,133.7	7,851.2	(16,744.0)	5,685.4
Total liabilities and equity	$9,184.8	$11,763.0	$11,761.5	$ 16,182.8	$(32,046.2)	$16,845.9

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Condensed Consolidating Statements of Cash Flows

(Unaudited)	Three Months Ended March 31, 2018 Parent Issuer & Guarantor	Subsidiary Issuer & Guarantor	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
	(Millions of dollars)					
Operating activities						
Cash provided by operating activities	$266.8	$ 319.7	$ 17.1	$ 557.7	$ (666.0)	$495.3
Investing activities						
Capital expenditures	(5.7)	—	—	(258.8)	—	(264.5)
Contributions to unconsolidated affiliates	—	—	—	(0.1)	—	(0.1)
Other investing activities	—	—	5.0	4.0	—	9.0
Cash provided by (used in) investing activities	(5.7)	—	5.0	(254.9)	—	(255.6)
Financing activities						
Dividends paid	(316.4)	(333.0)	(333.0)	—	666.0	(316.4)
Distributions to noncontrolling interests	—	—	—	(1.5)	—	(1.5)
Intercompany borrowings (advances), net	(514.5)	513.3	310.9	(309.7)	—	—
Borrowing (repayment) of short-term borrowings, net	(614.7)	—	—	—	—	(614.7)
Repayment of long-term debt	—	(500.0)	—	(1.9)	—	(501.9)
Issuance of common stock	1,182.1	—	—	—	—	1,182.1
Other, net	(17.3)	—	—	10.3	—	(7.0)
Cash used in financing activities	(280.8)	(319.7)	(22.1)	(302.8)	666.0	(259.4)
Change in cash and cash equivalents	(19.7)	—	—	—	—	(19.7)
Cash and cash equivalents at beginning of period	37.2	—	—	—	—	37.2
Cash and cash equivalents at end of period	$17.5	$ —	$ —	$ —	$ —	$17.5

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(Unaudited)	Parent Issuer & Guarantor	Subsidiary Issuer & Guarantor	Guarantor Subsidiary	Combined Non-Guarantor Subsidiaries	Consolidating Entries	Total
	Three Months Ended March 31, 2017					
	(Millions of dollars)					
Operating activities						
Cash provided by operating activities	$134.2	$322.1	$18.8	$324.5	$(530.5)	$269.1
Investing activities						
Capital expenditures	(0.1)	—	—	(112.6)	—	(112.7)
Other investing activities	—	—	2.9	0.3	—	3.2
Cash provided by (used in) investing activities	(0.1)	—	2.9	(112.3)	—	(109.5)
Financing activities						
Dividends paid	(129.8)	(333.0)	(333.0)	—	666.0	(129.8)
Distributions to noncontrolling interests	—	—	—	(1.2)	(135.5)	(136.7)
Intercompany borrowings (advances), net	52.1	(162.4)	319.4	(209.1)	—	—
Borrowing (repayment) of short-term borrowings, net	—	180.5	—	—	—	180.5
Repayment of long-term debt	(0.1)	—	—	(1.9)	—	(2.0)
Issuance of common stock	3.7	—	—	—	—	3.7
Other	(6.2)	(7.2)	—	—	—	(13.4)
Cash used in financing activities	(80.3)	(322.1)	(13.6)	(212.2)	530.5	(97.7)
Change in cash and cash equivalents	53.8	—	8.1	—	—	61.9
Cash and cash equivalents at beginning of period	248.5	—	0.4	—	—	248.9
Cash and cash equivalents at end of period	$302.3	$—	$8.5	$—	$—	$310.8

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ITEM 2. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with our unaudited Consolidated Financial Statements and the Notes to Consolidated Financial Statements in this Quarterly Report, as well as our Annual Report.

RECENT DEVELOPMENTS

Please refer to the “Financial Results and Operating Information” and “Liquidity and Capital Resources” sections of Management’s Discussion and Analysis of Financial Condition and Results of Operations in this Quarterly Report for additional information.

Merger Transaction - On June 30, 2017, we completed the acquisition of all of the outstanding common units of ONEOK Partners that we did not already own. Prior to June 30, 2017, we and our subsidiaries owned all of the general partner interest, which included incentive distribution rights, and a portion of the limited partner interest, which together represented a 41.2 percent ownership interest in ONEOK Partners. The earnings of ONEOK Partners that are attributed to its units held by the public during first quarter 2017 are reported as “Net income attributable to noncontrolling interest” in our Consolidated Statement of Income. Our general partner incentive distribution rights effectively terminated at the closing of the Merger Transaction.

Business Update and Market Conditions - We operate primarily fee-based businesses in each of our three reportable segments, and we expect our consolidated earnings to be approximately 90 percent fee-based in 2018. Volumes increased across our asset footprint in our Natural Gas Gathering and Processing and Natural Gas Liquids segments in the first quarter 2018, compared with the same period in 2017, as producers experienced improved drilling economics, continued improvements in production due to enhanced completion techniques and more efficient drilling rigs.

We are connected to supply in growing basins and have significant basin diversification across our asset footprint, including the Williston, DJ, Permian and Powder River Basins and the STACK and SCOOP areas. Across this footprint, there was an increase in producer activity and demand for ethane from ethylene producers and NGL exporters in the Gulf Coast in 2017 and the first quarter 2018, which we expect to continue throughout the remainder of 2018. In addition, we are connected to major market centers for natural gas and NGL products. While our Natural Gas Gathering and Processing and Natural Gas Liquids segments generate primarily fee-based earnings, those segments’ results of operations are exposed to volumetric risk. Our exposure to volumetric risk can result from declining well productivity, reduced drilling activity, severe weather disruptions, operational outages, ethane rejection and competition for supply.

Rocky Mountain Region - We expect each of our business segments to benefit from increased production in this region, which includes the Williston, DJ and Powder River Basins. In our Natural Gas Gathering and Processing segment, our completed capital-growth projects have increased our gathering and processing capacity to approximately 1.0 Bcf/d in the Williston Basin and allow us to capture additional natural gas from the approximately 1 million acres dedicated to us in the core of this basin and approximately 3 million acres throughout the entire basin. With continued volume growth expected due to improved drilling economics and producer efficiencies, we announced plans to construct the 200 MMcf/d Demicks Lake natural gas processing plant in the core of the Williston Basin, which is expected to provide services necessary to help producers meet natural gas capture targets, while adding incremental NGLs to our NGL gathering system and supplying natural gas to our 50 percent owned Northern Border Pipeline. We are also expanding our existing Bear Creek natural gas processing plant in the Williston Basin to 130 MMcf/d from 80 MMcf/d. In our Natural Gas Liquids segment, the volume growth in this region has resulted in our existing Bakken NGL Pipeline and the Overland Pass Pipeline, of which we own 50 percent, operating at full capacity. We also announced plans to construct the Elk Creek pipeline, which is expected to strengthen our position in the high-production areas of the Williston, DJ and Powder River Basins and provide needed infrastructure to transport NGLs out of the region.

STACK and SCOOP - As producers continue to develop the STACK and SCOOP areas, we expect increased demand for our services from producers that need incremental takeaway capacity for natural gas and NGLs out of the Mid-Continent region. We anticipate NGL volume growth will also be driven by continued increases in ethane recovery as ethylene producers continue to complete their expansion projects and NGL exporters increase their export volumes. In our Natural Gas Gathering and Processing segment, we have more than 300,000 acres dedicated to us in the STACK and SCOOP areas and are responding to producers' needs by constructing the 200 MMcf/d expansion of our Canadian Valley natural gas processing plant, which will increase our capacity to 1.1 Bcf/d in Oklahoma. In our Natural Gas Liquids segment, we are the largest NGL takeaway provider in the STACK and SCOOP areas. We are expanding our NGL gathering system in the Mid-Continent region, expanding our existing Sterling III pipeline and plan to construct the Arbuckle II pipeline. The Arbuckle II pipeline will

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transport NGLs originating across our supply basins to Mont Belvieu, Texas. In our Natural Gas Pipelines segment, we are connected to more than 30 natural gas processing plants in Oklahoma, which have a total processing capacity of approximately 1.8 Bcf/d, and we recently expanded our ONEOK Gas Transportation pipeline by 100 MMcf/d to provide increased westbound transportation services from the STACK and SCOOP areas.

Permian Basin - We expect our Natural Gas Liquids and Natural Gas Pipelines business segments to benefit from increased production in the Permian Basin from the highly productive Delaware and Midland Basins. In our Natural Gas Liquids segment, we are well-positioned in the Permian Basin through our WTLPG joint venture, which is extending its pipeline system into the core of the Delaware Basin through construction of an approximately 120-mile pipeline lateral and related infrastructure. This project positions the West Texas LPG pipeline for significant future NGL volume growth. In our Natural Gas Pipelines segment, Roadrunner and our WesTex pipeline are well-positioned to serve growth in the Permian Basin. The Roadrunner pipeline connects with our existing natural gas pipeline and storage infrastructure in Texas and, together with our completed WesTex intrastate natural gas pipeline expansion project, creates future opportunities for us to deliver natural gas supply to Mexico and transport natural gas to other markets in the region.

Gulf Coast - Demand for NGLs is expected to grow at the NGL market center in Mont Belvieu, Texas, as new world-scale ethylene production projects, petrochemical plant expansions and NGL export facilities are completed. We expect increased NGL supply across our assets and construction of our Sterling III and WTLPG pipeline expansions, Elk Creek pipeline and Arbuckle II pipeline projects to result in higher NGL deliveries to this NGL market center. We have significant NGL fractionation and storage assets in this area, and additional capacity is needed to accommodate expected volume growth. To respond to this need, we announced plans to construct the 125 MBbl/d MB-4 fractionator and related infrastructure in Mont Belvieu, Texas, which includes additional NGL storage capacity. Following the completion of MB-4, we expect our total NGL fractionation capacity to be 965 MBbl/d.

Ethane Opportunity - Ethane demand has increased as ethane exports have increased and petrochemical companies have completed ethylene production projects and plant expansions. Ethane volumes across our system increased approximately 50 MBbl/d in the first quarter 2018, compared with the same period in the prior year. As NGL supply continues to increase, new plants are added or existing plants are modified to increase ethane recoveries, the amount of ethane volumes across our system and the amount of ethane rejected are expected to continue to fluctuate. In the first quarter 2018, ethane rejection levels across our system averaged more than 140 MBbl/d. We expect ethane rejection levels across our system to decrease to approximately 70 MBbl/d by the end of 2018, as ethylene producers continue to complete their expansion projects and NGL exporters increase their export volumes. We expect much of the ethane supply in the Rocky Mountain region to continue to be rejected.

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Growth Projects - Increased producer activity and volume growth across our assets have increased demand for midstream infrastructure. We are responding to this growing demand by constructing assets to meet the needs of natural gas processors and producers across our asset footprint, including the Williston, DJ, Permian and Powder River Basins and the STACK and SCOOP areas. We also expect additional demand for our services to support increased demand for NGL products from the petrochemical industry and NGL exporters, and increased demand for natural gas from exports and power plants, some of which were previously fueled by coal. Since June 2017, we have announced approximately $4.2 billion of additional capital-growth projects supported by a combination of long-term primarily fee-based contracts, minimum volume commitments and acreage dedications to serve the expected growth and needs of natural gas processors and producers. We have contracted a substantial amount of the steel required for our pipeline projects from vendors in the United States and Canada. Our announced capital-growth projects are outlined in the table below:

Project	Scope	Approximate Costs (a) (in millions)	Completion Date
Natural Gas Gathering and Processing			
Additional STACK processing capacity	200 MMcf/d processing capacity through long-term processing services agreement	$40	December 2017
Canadian Valley expansion	30-mile natural gas gathering pipeline 200 MMcf/d processing plant expansion in the STACK area and related gathering infrastructure Increases capacity to more than 400 MMcf/d 20 MBbl/d additional NGL volume Supported by acreage dedications, long-term primarily fee-based contracts and minimum volume commitments	160	Fourth Quarter 2018
Demicks Lake plant and related infrastructure	200 MMcf/d processing plant and related infrastructure in the core of the Williston Basin Supported by acreage dedications with long-term primarily fee-based contracts	400	Fourth Quarter 2019
Total Natural Gas Gathering and Processing		$600	
Natural Gas Liquids			
WTLPG pipeline expansion	120-mile pipeline lateral extension with capacity of 110 MBbl/d in the Permian Basin Supported by long-term dedicated NGL production from two planned third-party natural gas processing plants	$160 (b)	Third Quarter 2018
Sterling III pipeline expansion and Arbuckle connection	60 MBbl/d NGL pipeline expansion Increases capacity to 250 MBbl/d Includes additional NGL gathering system expansions Supported by long-term third-party contract	130	Fourth Quarter 2018
Elk Creek pipeline and related infrastructure	900-mile NGL pipeline from the Williston Basin to the Mid-Continent region with initial capacity of 240 MBbl/d, and related infrastructure Anchored by long-term contracts supported primarily by minimum volume commitments Expansion capability up to 400 MBbl/d with additional pump facilities	1,400	Fourth Quarter 2019
Arbuckle II pipeline and related infrastructure	530-mile NGL pipeline from the STACK area to Mont Belvieu, Texas, with initial capacity up to 400 MBbl/d, and related infrastructure	1,360	First Quarter 2020

	Supported by long-term contracts Expansion capability up to 1,000 MBbl/d		
MB-4 fractionator and related infrastructure	125 MBbl/d NGL fractionator in Mont Belvieu, Texas, and related infrastructure, which includes additional NGL storage in Mont Belvieu Fully contracted with long-term contracts	575	First Quarter 2020
Total Natural Gas Liquids		$3,625	
Total		$4,225	

(a) - Excludes capitalized interest/AFUDC.
(b) - Represents our portion of the total project cost of $200 million.

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Equity Issuances - In January 2018, we completed an underwritten public offering of 21.9 million shares of our common stock at a public offering price of $54.50 per share, generating net proceeds of $1.2 billion. We used the net proceeds from this offering to fund capital expenditures and for general corporate purposes, which included repaying a portion of our outstanding indebtedness. We have satisfied our expected equity financing needs through the remainder of 2018 and well into 2019.

Dividends - In February 2018, we paid a quarterly dividend of $0.77 per share ($3.08 per share on an annualized basis), an increase of 25 percent compared with the same period in the prior year. We declared a quarterly dividend of $0.795 per share ($3.18 per share on an annualized basis) in April 2018. The quarterly dividend will be paid May 15, 2018, to shareholders of record at the close of business on April 30, 2018. We expect 85 to 95 percent of our 2018 dividend payments to investors to be a return of capital. Our dividend growth is due to the increase in cash flows resulting from the Merger Transaction and the continued growth of our operations.

FERC Action - The Tax Cuts and Jobs Act makes extensive changes to the U.S. tax laws and includes provisions that reduce the U.S. corporate tax rate to 21 percent from 35 percent, increase expensing for capital investment, and limit the interest deduction and use of net operating losses to offset future taxable income. The Tax Cuts and Jobs Act may reduce future tariff rates charged on our regulated pipelines. The rates charged to our customers have generally been established through shipper specific negotiation, discounts and negotiated settlements, which do not ascribe any specific cost of service elements. We expect future tariff rate changes, if any, related to the change in the U.S. corporate tax rate to be established prospectively over time on a similar negotiated basis. We will continue to monitor applicable FERC rule-making, including the March 2018 notice of proposed rule-making on the impact of the Tax Cuts and Jobs Act on FERC-regulated rates for natural gas pipelines, which is subject to a public comment process prior to being finalized. If in the future the FERC or other regulatory bodies were to require us to establish a regulatory liability for amounts previously collected on our regulated pipelines, then we would expect to record a regulatory liability through a one-time charge to expense.

We also continue to monitor the FERC’s March 2018 revised policy statement for master limited partnerships, which no longer allows interstate natural gas and oil pipelines owned by master limited partnerships to recover an income tax allowance in cost of service rates. This revised policy remains pending at the FERC based on various requests for reconsideration or rehearing. We do not expect this FERC action to be material to our results of operations, as we are organized as a C-corporation. Further, regardless of organizational structure, we do not expect this FERC action to materially affect us, as the rates charged to our customers have generally been established through shipper specific negotiation, discounts and negotiated settlements, which do not ascribe any specific cost of service elements.

The FERC allows regulated NGL pipelines an annual index adjustment to transportation rates, which is intended to allow recovery of changes in costs without a complicated cost of service filing. The FERC is expected to evaluate how best to incorporate the effects of new tax policies in its next calculation of the rate index in 2020, for indexing effective July 2021. We do not expect to be materially impacted by any such change in the index calculation, as our regulated NGL pipeline revenues are primarily under negotiated agreements.

Revenue Recognition - We adopted Topic 606 on January 1, 2018, using the modified retrospective method. Results for reporting periods beginning after January 1, 2018, are presented under Topic 606, while prior periods are not adjusted and continue to be reported under the accounting standards in effect for those periods. The primary impact to our financial results is a classification change between line items in our Consolidated Income Statement, with an immaterial impact on net income. Based on the new guidance, we determined that certain Natural Gas Gathering and Processing segment POP with fee contracts and Natural Gas Liquids segment exchange services contracts that include the purchase of commodities are supplier contracts. Therefore, contractual fees in these identified contracts are now recorded as a reduction of the commodity purchase price in cost of sales and fuel rather than as services revenue. To the extent we hold inventory related to these purchases, the related fees previously recorded in services revenue will not be recognized until the inventory is sold. For the three months ended March 31, 2018, we recorded approximately $352.6 million of contractual fees charged under these contracts as a reduction of the commodity purchase price in cost of sales and fuel that we would have recorded as services revenue in our Consolidated Income Statements prior to adoption of Topic 606. The change in presentation resulting from the adoption of Topic 606 did not materially impact our reported operating income, net income or adjusted EBITDA.

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FINANCIAL RESULTS AND OPERATING INFORMATION

Consolidated Operations

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

Financial Results	Three Months Ended March 31, 2018	2017	Three Months 2018 vs. 2017 Increase (Decrease)	
	(Millions of dollars)			
Revenues				
Commodity sales	$2,820.0	$2,216.7	$603.3	27 %
Services	282.1	532.9	(250.8)	(47%)
Total revenues	3,102.1	2,749.6	352.5	13 %
Cost of sales and fuel (exclusive of items shown separately below)	2,368.0	2,143.8	224.2	10 %
Operating costs	210.3	189.3	21.0	11 %
Depreciation and amortization	104.2	99.4	4.8	5 %
(Gain) loss on sale of assets	(0.1)	—	0.1	*
Operating income	$419.7	$317.1	$102.6	32 %
Equity in net earnings from investments	$40.2	$39.6	$0.6	2 %
Interest expense, net of capitalized interest	$(115.7)	$(116.5)	$(0.8)	(1 %)
Net income	$266.0	$186.2	$79.8	43 %
Adjusted EBITDA	$570.3	$459.6	$110.7	24 %
Capital expenditures	$264.5	$112.7	$151.8	*

* Percentage change is greater than 100 percent or is not meaningful
See reconciliation of net income to adjusted EBITDA in the “Adjusted EBITDA” section.

Due to the nature of our contracts, changes in commodity prices and sales volumes affect both commodity sales and cost of sales and fuel in our Consolidated Statements of Income, and, therefore, the impact is largely offset between the two line items. Due to adoption of Topic 606 in January 2018, we recorded $352.6 million of fees associated with contracts that include the purchase of commodities as a reduction to the commodity purchase price in cost of sales and fuel during the three months ended March 31, 2018, that would have been recorded as services revenue prior to adoption. Total contractual fees, regardless of classification on our Consolidated Income Statements, increased by $98.5 million to $624.0 million in the first quarter 2018, compared with $525.5 million in the same period in the prior year.

Operating income and adjusted EBITDA increased for the three months ended March 31, 2018, compared with the same period in 2017, due primarily to higher revenues resulting from volume growth in the Williston Basin and STACK and SCOOP areas in our Natural Gas Gathering and Processing segment; volume growth in the Mid-Continent region, primarily the STACK and SCOOP areas, and the Williston and Permian Basins in our Natural Gas Liquids segment; higher optimization and marketing earnings due primarily to wider location price differentials and the sale of NGL inventory previously held in our Natural Gas Liquids segment; and the impact of $7 million in operating costs related to the Merger Transaction in the first quarter 2017. These increases were offset partially by higher operating costs related to employee-related costs associated with labor and benefits in all three of our segments, materials, supplies and outside services costs in our Natural Gas Gathering and Processing segment related to the growth of our operations and the timing of routine maintenance projects in our Natural Gas Liquids segment. Operating income was also impacted by higher depreciation expense in the three months ended March 31, 2018, compared with the same period in 2017, due to capital-growth projects placed in service.

Capital expenditures increased for the three months ended March 31, 2018, compared with the same period in 2017, due primarily to spending on our recently announced capital-growth projects.

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

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Natural Gas Gathering and Processing

Overview - Our Natural Gas Gathering and Processing segment provides midstream services to contracted producers in North Dakota, Montana, Wyoming, Kansas and Oklahoma. Raw natural gas is typically gathered at the wellhead, compressed and transported through pipelines to our processing facilities. In order for the natural gas to be accepted by the downstream market, it must have contaminants, such as water, nitrogen and carbon dioxide, removed and NGLs separated for further processing. Processed natural gas, usually referred to as residue natural gas, is then recompressed and delivered to natural gas pipelines, storage facilities and end users. The separated NGLs are sold and delivered through natural gas liquids pipelines to fractionation facilities for further separation.

Demand for gathering and processing services is dependent on natural gas production by producers, which is driven by the strength of the economy; producer firm commitments to transportation pipelines; natural gas, crude oil and NGL prices; and the demand for each of these products from end users. We generally contract with crude oil and natural gas producers who have proven reserves or are currently producing natural gas in areas within our existing infrastructure and need gathering and processing services.

The Williston Basin, which is located in portions of North Dakota and Montana, including the oil-producing, NGL-rich Bakken Shale and Three Forks formations, is an active drilling region. Our completed capital-growth projects in the Williston Basin since 2016 have increased our processing capacity to approximately 1.0 Bcf/d and allow us to capture increased natural gas production from new wells and previously flared natural gas production. Demand for our gathering and processing services in the Williston Basin has remained strong in both high and low commodity price environments. Requirements in North Dakota for producers to reduce natural gas flaring have increased the need for our services to gather and process natural gas, and we are responding by constructing the recently announced Demicks Lake natural gas processing plant and related infrastructure. In the Williston Basin we have approximately 125 MMcf/d of available capacity. Upon completion of the Demicks Lake plant, we will have approximately 1.2 Bcf/d of processing capacity in this basin.

The Mid-Continent is an active drilling region and includes the oil-producing, NGL-rich STACK and SCOOP areas and the Cana-Woodford Shale, Woodford Shale, Springer Shale, Meramec, Granite Wash and Mississippian Lime formations of Oklahoma and Kansas; and the Hugoton and Central Kansas Uplift Basins of Kansas. As producers continue to develop the STACK and SCOOP areas, we expect increased demand for our services. We have approximately 75 MMcf/d of available processing capacity in Oklahoma. We are responding to producers' needs by constructing the 200 MMcf/d expansion of our Canadian Valley natural gas processing plant, which will increase our processing capacity to 1.1 Bcf/d in Oklahoma.

The Powder River Basin is primarily located in Wyoming, which includes the NGL-rich Niobrara Shale and Frontier, Turner and Sussex formations where we provide gathering and processing services to customers in the southeast portion of Wyoming.

Revenues for this segment are derived primarily from commodity sales and service contracts. For commodity sales, we contract to deliver residue natural gas, condensate and/or unfractionated NGLs to downstream customers at a specified delivery point. Our sales of NGLs are typically to our affiliate in the Natural Gas Liquids segment. For fee-only contracts, we are paid a fee for the services we provide, based on volumes gathered, processed, treated and/or compressed. Under a POP with fee contract, we charge fees for gathering, treating, compressing and processing the producer's natural gas. We also generally purchase the producer's raw natural gas, which we process into residue natural gas and NGLs, then we sell these commodities and associated condensate to downstream customers. We remit sales proceeds to the producer according to the contractual terms and retain our portion. Upon adoption of Topic 606 in January 2018, the contractual fees we charge producers on the majority of our POP with fee contracts are now recorded as a reduction to the commodity purchase price in cost of sales and fuel. In 2017 and prior periods, we recorded these fees as services revenue. The contractual fees on POP with fee contracts that include producer take-in-kind rights will continue to be recorded as services revenue, as we do not control the raw natural gas stream while we are providing midstream services.

Our Natural Gas Gathering and Processing segment’s earnings are primarily fee-based, but have some direct commodity price exposure related primarily to POP contracts. To mitigate the impact of this commodity price exposure, we have hedged a significant portion of our Natural Gas Gathering and Processing segment’s commodity price risk for 2018 and 2019. This segment has substantial long-term acreage dedications in some of the most productive areas of the Williston Basin and Mid-Continent region, specifically the STACK and SCOOP areas, which helps to mitigate volumetric risk.

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Our natural gas gathered and processed volumes increased for the three months ended March 31, 2018, compared with the same period in 2017, due primarily to the following:

- producers focusing their drilling and completion in the most productive areas with favorable economics where we have significant gathering and processing assets; and
- continued producer improvements in production due to enhanced completion techniques and more efficient drilling rigs; offset partially by
- natural production declines.

We expect our natural gas volumes to continue to increase in 2018 due to the production activities discussed above.

Growth Projects - Our Natural Gas Gathering and Processing segment is investing in growth projects in NGL-rich areas, including the Bakken Shale and Three Forks formations in the Williston Basin and the STACK and SCOOP areas, that we expect will enable us to meet the needs of crude oil and natural gas producers in those areas. Nearly all of the new natural gas production is from horizontally drilled wells in nonconventional resource areas. These wells tend to produce volumes at higher initial production rates resulting generally in higher initial decline rates than conventional vertical wells; however, the decline rates flatten out over time. These wells are expected to have long productive lives. See “Growth Projects” in the “Recent Developments” section for discussion of our announced capital-growth projects.

We continue to evaluate opportunities to increase the capacity of our gathering and processing assets or construct new assets to accommodate supply growth from the Williston Basin and Mid-Continent region.

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

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

Financial Results	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017	Three Months 2018 vs. 2017 Increase (Decrease)	
	(Millions of dollars)			
NGL sales	$362.8	$245.5	$117.3	48 %
Condensate sales	50.4	19.0	31.4	*
Residue natural gas sales	255.0	210.5	44.5	21 %
Gathering, compression, dehydration and processing fees and other revenue	39.8	186.3	(146.5)	(79%)
Cost of sales and fuel (exclusive of depreciation and operating costs)	(492.6)	(488.4)	4.2	1 %
Operating costs	(88.4)	(71.3)	17.1	24 %
Equity in net earnings from investments; excluding noncash impairment charges	1.7	2.6	(0.9)	(35%)
Other	1.9	(0.2)	2.1	*
Adjusted EBITDA	$130.6	$104.0	$26.6	26 %
Capital expenditures	$111.7	$63.2	$48.5	77 %

* Percentage change is greater than 100 percent.

See reconciliation of net income to adjusted EBITDA in the “Adjusted EBITDA” section.

Due to the nature of our contracts, changes in commodity prices and sales volumes affect commodity sales and cost of sales and fuel, and, therefore, the impact is largely offset between these line items. As a result of our January 1, 2018, adoption of Topic 606, we recorded $194.8 million of fees charged on POP with fee contracts that include the purchase of commodities as a reduction to cost of sales and fuel during the three months ended March 31, 2018, that would have been recorded as services revenue prior to the adoption. Total contractual fees, regardless of classification on our Consolidated Income Statements, increased by $48.5 million to $233.2 million in the first quarter 2018, compared with $184.7 million in the same period in the prior year.

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Adjusted EBITDA increased $26.6 million for the three months ended March 31, 2018, compared with the same period in 2017, primarily as a result of the following:

- an increase of $41.5 million due primarily to natural gas volume growth in the Williston Basin and the STACK and SCOOP areas, offset partially by natural production declines; offset partially by
- an increase of $17.1 million in operating costs due primarily to increased materials and supplies and outside services related to the growth of our operations and higher employee-related costs associated with labor and benefits.

Capital expenditures increased for the three months ended March 31, 2018, compared with the same period in 2017, due to recently announced capital-growth projects and increased well connections.

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

	Three Months Ended March 31,	
Operating Information (a)	2018	2017
Natural gas gathered (BBtu/d)	2,460	1,985
Natural gas processed (BBtu/d) (b)	2,285	1,863
NGL sales (MBbl/d)	194	172
Residue natural gas sales (BBtu/d)	964	793
Average contractual fee rate ($/MMBtu)	$0.88	$0.83

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

Natural gas gathered, natural gas processed, NGL sales and residue natural gas sales increased during the three months ended March 31, 2018, compared with the same period in 2017, due to new supply in the Williston Basin and STACK and SCOOP areas, offset partially by natural production declines on existing wells.

The quantity and composition of NGLs and natural gas are expected to continue to change with anticipated production increases across our supply basins, new processing plants placed in service and increased ethane recovery.

Commodity Price Risk - See discussion regarding our commodity price risk and our expected equity volumes under “Commodity Price Risk” in Item 3, Quantitative and Qualitative Disclosures about Market Risk in this Quarterly Report.

Natural Gas Liquids

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

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

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Revenues for our Natural Gas Liquids segment are derived primarily from commodity sales and fee-based services. We also purchase NGLs and condensate from third parties, as well as from our Natural Gas Gathering and Processing segment. Our fee-based services have increased due primarily to new supply connections, expansion of existing connections and the completion of capital-growth projects. Our business activities are categorized as exchange services, transportation and storage services, and optimization and marketing, which are defined as follows:

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

In many of our exchange services contracts, we purchase the unfractionated NGLs at the tailgate of the processing plant and deduct contractual fees related to the transportation and fractionation services we must perform before we can sell them as NGL products. Upon adoption of Topic 606 in January 2018, the contractual fees we charge are now recorded as a reduction to the commodity purchase price in cost of sales and fuel. In 2017 and prior periods, we recorded these fees as exchange services revenue.

Supply growth from the development of NGL-rich areas and capacity available on pipelines that connect the Mid-Continent and Gulf Coast resulted in relatively narrow NGL price differentials between the Mid-Continent market center at Conway, Kansas, and the Gulf Coast market center at Mont Belvieu, Texas, for the past several years. For the past two quarters, we have experienced wider NGL price differentials for certain NGLs, including ethane, as demand increased from petrochemical companies completing expansion projects and international demand for NGLs increased as a result of increased export volumes. We expect NGL price differentials to fluctuate more widely as supply growth and market demand find equilibrium.

Supply growth has resulted in available ethane supply that has been greater than the petrochemical industry’s demand. Low or unprofitable price differentials between ethane and natural gas have resulted in varied levels of ethane rejection since early 2012 at most of our and our customers’ natural gas processing plants connected to our NGL system in the Mid-Continent and Rocky Mountain regions. Ethane demand has increased as ethane exports have increased and petrochemical companies have completed ethylene production projects and plant expansions. Ethane volumes across our system increased approximately 50 MBbl/d in the first quarter 2018, compared with the same period in the prior year. As NGL supply continues to increase, new plants are added or existing plants are modified to increase ethane recoveries, the amount of ethane volumes across our system and the amount of ethane rejected are expected to continue to fluctuate. In the first quarter 2018, ethane rejection levels across our system averaged more than 140 MBbl/d. We expect ethane rejection levels across our system to decrease to approximately 70 MBbl/d by the end of 2018, as ethylene producers continue to complete their expansion projects and NGL exporters increase their export volumes. We expect much of the ethane supply in the Rocky Mountain region to continue to be rejected.

Growth Projects - Our growth strategy in our Natural Gas Liquids segment is focused around the crude oil and NGL-rich natural gas drilling activity in shale and other nonconventional resource areas from the Rocky Mountain region through the Mid-Continent region into the Permian Basin. Crude oil, natural gas and NGL production from this activity; higher petrochemical industry demand for NGL products; and increased exports have resulted in additional capital investments to expand our infrastructure to bring these commodities from supply basins to market.

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

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export demand in the Gulf Coast. See “Growth Projects” in the “Recent Developments” section for discussion of our announced capital-growth projects.

We continue to evaluate opportunities to increase the capacity of our gathering and fractionation assets or construct new assets to connect supply growth from the Williston Basin, Mid-Continent and Permian Basin with end-use markets.

In the first quarter 2018, a third-party natural gas processing plant was expanded on our NGL system in the STACK and SCOOP areas of the Mid-Continent region.

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

Selected Financial Results - The following table sets forth certain selected financial results for our Natural Gas Liquids segment for the periods indicated:

Financial Results	Three Months Ended March 31, 2018	2017	Three Months 2018 vs. 2017 Increase (Decrease)	
	(Millions of dollars)			
NGL and condensate sales	$2,552.8	$2,008.0	$544.8	27 %
Exchange service revenues and other	86.2	333.3	(247.1)	(74%)
Transportation and storage revenues	53.5	50.7	2.8	6 %
Cost of sales and fuel (exclusive of depreciation and operating costs)	(2,281.1)	(2,048.7)	232.4	11 %
Operating costs	(88.6)	(78.4)	10.2	13 %
Equity in net earnings from investments	16.4	13.7	2.7	20 %
Other	2.9	(0.4)	3.3	*
Adjusted EBITDA	$342.1	$278.2	$63.9	23 %
Capital expenditures	$124.9	$20.5	$104.4	*

* Percentage change is greater than 100 percent.
See reconciliation of net income to adjusted EBITDA in the “Adjusted EBITDA” section.

Due to the nature of our contracts, changes in commodity prices and sales volumes affect commodity sales and cost of sales and fuel, and, therefore, the impact is largely offset between these line items. As a result of our January 1, 2018, adoption of Topic 606, we recorded $293.6 million of fees charged on exchange services contracts that include the purchase of natural gas liquids as a reduction to cost of sales and fuel during the three months ended March 31, 2018, that would have been recorded as services revenue prior to adoption. Total contractual fees, regardless of classification on our Consolidated Income Statements, increased by $49.7 million to $430.3 million in the first quarter 2018, compared with $380.6 million in the same period in the prior year. A portion of these contractual fees are with our Natural Gas Gathering and Processing segment and are eliminated in consolidation.

Adjusted EBITDA increased $63.9 million for the three months ended March 31, 2018, compared with the same period in 2017, primarily as a result of the following:

- an increase of $43.4 million in exchange services due to increased volumes, including higher ethane recovery in the Mid-Continent region, primarily in the STACK and SCOOP areas, and increased volumes in the Williston and Permian Basins, offset partially by lower volumes in the Barnett Shale and the impact of severe winter weather in 2018;
- an increase of $24.9 million in optimization and marketing due primarily to wider location price differentials and the sale of NGL inventory previously held; and

- an increase of $2.7 million in equity in net earnings from investments due primarily to higher volumes delivered to Overland Pass Pipeline from our Bakken NGL Pipeline; offset partially by
- an increase of $10.2 million in operating costs due primarily to higher employee-related costs associated with labor and benefits, timing of routine maintenance projects and ad valorem taxes.

Capital expenditures increased for the three months ended March 31, 2018, compared with the same period in 2017, due primarily to our recently announced capital-growth projects.

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

	Three Months Ended March 31,	
Operating Information	2018	2017
NGLs transported-gathering lines (MBbl/d) (a)	855	764
NGLs fractionated (MBbl/d) (b)	693	574
NGLs transported-distribution lines (MBbl/d) (a)	597	550
Average Conway-to-Mont Belvieu OPIS price differential - ethane in ethane/propane mix ($/gallon)	$0.09	$0.03

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

NGLs transported on gathering lines and NGLs fractionated increased for the three months ended March 31, 2018, compared with the same period in 2017, due to increased volumes, including higher ethane recovery in the Mid-Continent region, primarily in the STACK and SCOOP areas, and increased volumes in the Williston and Permian Basins. These increases were offset partially by lower volumes from the Barnett Shale and the impact of severe winter weather in the first quarter 2018. NGLs transported on gathering lines were also impacted by higher volumes from the Permian Basin. While overall NGL volumes, including ethane, across our system increased, a portion of the contractual fees associated with those volumes gathered and fractionated was previously being earned under contracts with minimum volume obligations.

NGLs transported on distribution lines increased for the three months ended March 31, 2018, compared with the same period in 2017, due primarily to the increased NGLs gathered and fractionated discussed above.

Natural Gas Pipelines

Overview - Our Natural Gas Pipelines segment provides transportation and storage services to end users through its wholly owned assets and its 50 percent ownership interests in Northern Border Pipeline and Roadrunner.

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

- Midwestern Gas Transmission, which is a bidirectional system that interconnects with Tennessee Gas Transmission Company’s pipeline near Portland, Tennessee, and with several interstate pipelines that have access to both the Utica Shale and the Marcellus Shale at the Chicago Hub near Joliet, Illinois;
- Viking Gas Transmission, which is a bidirectional system that interconnects with a TransCanada Corporation pipeline at the United States border near Emerson, Canada, and ANR Pipeline Company near Marshfield, Wisconsin;
- Guardian Pipeline, which interconnects with several pipelines at the Chicago Hub near Joliet, Illinois, and with local natural gas distribution companies in Wisconsin; and
- OkTex Pipeline, which has interconnections with several pipelines in Oklahoma, Texas and New Mexico.

Intrastate Pipelines - Our intrastate natural gas pipeline assets in Oklahoma transport natural gas through the state and have access to the major natural gas production areas in the Mid-Continent region, which include the STACK and SCOOP areas and the Cana-Woodford Shale, Woodford Shale, Springer Shale, Meramec, Granite Wash and Mississippian Lime formations. Our intrastate natural gas pipeline assets in Oklahoma serve end-use markets, such as local distribution companies and power generation companies. In Texas, our intrastate natural gas pipelines are connected to the major natural gas producing formations in the Texas Panhandle, including the Granite Wash formation and Delaware, Cline and Midland producing formations in the Permian Basin. These pipelines are capable of transporting natural gas throughout the western portion of Texas, including the Waha Hub where other pipelines may be accessed for transportation to western markets, exports to Mexico, the Houston Ship Channel market to the east and the Mid-Continent market to the north. Our intrastate natural gas pipeline assets also have access to the Hugoton and Central Kansas Uplift Basins in Kansas.

Revenues in this segment are derived primarily from transportation and storage services.

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

- Firm service - Customers reserve a fixed quantity of pipeline capacity for a specified period of time, which obligates the customer to pay regardless of usage. Under this type of contract, the customer pays a monthly fixed fee and

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incremental fees, known as commodity charges, which are based on the actual volumes of natural gas they transport or store. Under the firm service contract, the customer generally is guaranteed access to the capacity they reserve.

- Interruptible service - Under interruptible service transportation agreements, the customer may utilize available capacity after firm service requests are satisfied. The customer is not guaranteed use of our pipelines unless excess capacity is available.

Our regulated natural gas transportation services contracts are based upon rates stated in the respective tariffs, which have generally been established through shipper specific negotiation, discounts and negotiated settlements. The rates are filed with FERC or the appropriate state jurisdictional agencies. In addition, customers typically are assessed fees, such as a commodity charge, and we may retain a percentage or specified volume of natural gas in-kind based on the natural gas volumes transported.

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

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

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

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

Financial Results	Three Months Ended March 31, 2018	2017	Three Months 2018 vs. 2017 Increase (Decrease)	
	(Millions of dollars)			
Transportation revenues	$81.8	$82.0	$(0.2)	— %
Storage revenues	16.5	14.2	2.3	16 %
Residue natural gas sales and other revenues	11.6	10.6	1.0	9 %
Cost of sales and fuel (exclusive of depreciation and and operating costs)	(5.5)	(16.6)	(11.1)	(67%)
Operating costs	(33.2)	(31.6)	1.6	5 %
Equity in net earnings from investments	22.1	23.2	(1.1)	(5 %)
Other	0.3	1.2	(0.9)	(75%)
Adjusted EBITDA	$93.6	$83.0	$10.6	13 %
Capital expenditures	$19.9	$25.0	$(5.1)	(20%)

See reconciliation of net income to adjusted EBITDA in the “Adjusted EBITDA” section.

As a result of our January 1, 2018, adoption of Topic 606, we recorded $3.1 million of retained fuel charges as a reduction to cost of sales and fuel during the three months ended March 31, 2018, that would have been recorded as transportation or storage revenue prior to adoption.

Adjusted EBITDA increased $10.6 million for the three months ended March 31, 2018, compared with the same period in 2017, primarily as a result of the following:

- an increase of $4.8 million from transportation services due primarily to increased interruptible transportation volumes;
- an increase of $4.8 million from natural gas storage services due primarily to higher park-and-loan activity; and
- an increase of $3.2 million from net retained fuel due primarily to higher natural gas volumes retained; offset partially by

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- an increase of $1.6 million in operating costs due primarily to employee-related costs associated with labor and benefits; and
- a decrease of $1.1 million in equity in net earnings from investments due primarily to lower settled rates on Northern Border Pipeline.

Capital expenditures decreased for the three months ended March 31, 2018, compared with the same period in 2017, due primarily to timing of maintenance projects and the completion of capital-growth projects.

Selected Operating Information - The following table sets forth selected operating information for our Natural Gas Pipelines segment for the periods indicated:

	Three Months Ended March 31,	
Operating Information (a)	2018	2017
Natural gas transportation capacity contracted (MDth/d)	6,779	6,757
Transportation capacity subscribed	97 %	97 %

(a) - Includes volumes for consolidated entities only.

Our natural gas pipelines primarily serve end users, such as natural gas distribution and electric-generation companies, that require natural gas to operate their businesses regardless of location price differentials. The development of shale and other resource areas has continued to increase available natural gas supply, and we expect producers to demand incremental transportation services in the future as additional supply is developed. The abundance of natural gas supply and regulations on emissions from coal-fired electric-generation plants may also increase the demand for our services from electric-generation companies as they convert to a natural gas fuel source.

Roadrunner, in which we have a 50 percent ownership interest, has contracted all of its capacity through 2041.

Northern Border Pipeline, in which we have a 50 percent ownership interest, has contracted substantially all of its long-haul transportation capacity through the fourth quarter 2020.

Northern Border Pipeline entered into a settlement with shippers that was approved by the FERC in February 2018. The settlement provides for tiered rate reductions beginning January 1, 2018, that will reduce rates 12.5 percent by January 2020 compared with previous rates and requires new rates to be established by January 2024. We do not expect the resulting decrease in equity earnings and cash distributions from Northern Border Pipeline to be material to us.

In March 2018, the FERC initiated a review of Midwestern Gas Transmission Company'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.

Adjusted EBITDA

Adjusted EBITDA is a non-GAAP measure of our financial performance. Adjusted EBITDA is defined as net income adjusted for interest expense, depreciation and amortization, noncash impairment charges, income taxes, allowance for equity funds used during construction, noncash compensation expense and other noncash items. We believe this non-GAAP financial measure is useful to investors because it and similar measures are used by many companies in our industry as a measurement of financial performance and is commonly employed by financial analysts and others to evaluate our financial performance and to compare financial performance among companies in our industry.

Adjusted EBITDA should not be considered an alternative to net income, earnings per share or any other measure of financial performance presented in accordance with GAAP. Additionally, this calculation may not be comparable with similarly titled measures of other companies.

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A reconciliation of net income, the nearest comparable GAAP financial performance measure, to adjusted EBITDA for the three months ended March 31, 2018 and 2017, is as follows:

	Three Months Ended March 31,	
	2018	2017
Reconciliation of net income to adjusted EBITDA	(Thousands of dollars)	
Net income	$266,049	$186,185
Add:		
Interest expense, net of capitalized interest	115,725	116,462
Depreciation and amortization	104,237	99,419
Income taxes	75,771	54,941
Noncash compensation expense	9,226	1,647
Other noncash items and equity AFUDC	(672)	958
Adjusted EBITDA	$570,336	$459,612
Reconciliation of segment adjusted EBITDA to adjusted EBITDA		
Segment adjusted EBITDA:		
Natural Gas Gathering and Processing	$130,551	$103,967
Natural Gas Liquids	342,079	278,229
Natural Gas Pipelines	93,625	82,958
Other	4,081	(5,542)
Adjusted EBITDA	$570,336	$459,612

CONTINGENCIES

See Note J of the Notes to Consolidated Financial Statements in this Quarterly Report for a discussion of developments concerning the Gas Index Pricing Litigation.

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

LIQUIDITY AND CAPITAL RESOURCES

General - Our primary sources of cash inflows are operating cash flows, commercial paper, bank credit facilities, debt issuances and the issuance of common stock for our liquidity and capital resources requirements. In addition, we expect cash outflows related to i) capital expenditures and ii) dividends paid to shareholders to increase due to our announced capital-growth projects and the increase in the number of shares outstanding as a result of the close of the Merger Transaction, our recent equity issuances and higher anticipated dividends per share, subject to board of directors' approval. We expect to pay no significant cash income taxes through 2021.

We expect our sources of cash inflow to provide sufficient resources to finance our operations, capital expenditures and quarterly cash dividends, including expected future dividend increases. To the extent operating cash flows are not sufficient to fund our dividends, we may utilize short- and long-term debt and issuances of equity, as necessary or appropriate. We may access the capital markets to issue debt or equity securities as we consider prudent to provide liquidity to refinance existing debt, improve credit metrics or to fund capital expenditures. However, with $1.6 billion of equity issued in 2017 and January 2018, we have satisfied our expected equity financing needs through the remainder of 2018 and well into 2019. We expect to fund capital-growth projects with cash from operations, short-term borrowings and long-term debt.

We manage interest-rate risk through the use of fixed-rate debt, floating-rate debt and interest-rate swaps. For additional information on our interest rate swaps, see Note C of the Notes to Consolidated Financial Statements in this Quarterly Report.

Cash Management - We use a centralized cash management program that concentrates the cash assets of our operating subsidiaries in joint accounts for the purposes of providing financial flexibility and lowering the cost of borrowing, transaction costs and bank fees. Our centralized cash management program provides that funds in excess of the daily needs of our

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operating subsidiaries are concentrated, consolidated or otherwise made available for use by other entities within our consolidated group. Our operating subsidiaries participate in this program to the extent they are permitted pursuant to FERC regulations or their operating agreements. Under the cash management program, depending on whether a participating subsidiary has short-term cash surpluses or cash requirements, we provide cash to the subsidiary or the subsidiary provides cash to us.

Short-term Liquidity - Our principal sources of short-term liquidity consist of cash generated from operating activities, distributions received from our equity-method investments, proceeds from our commercial paper program and our $2.5 Billion Credit Agreement.

At March 31, 2018, we had $17.5 million of cash and cash equivalents and $2.5 billion of borrowing capacity under our $2.5 Billion Credit Agreement, and we were in compliance with all covenants of our $2.5 Billion Credit Agreement.

We had working capital (defined as current assets less current liabilities) deficits of $0.8 billion and $0.9 billion as of March 31, 2018, and December 31, 2017, respectively. Although working capital is influenced by several factors, including, among other things: (i) the timing of (a) scheduled debt payments, (b) the collection and payment of accounts receivable and payable, and (c) equity and debt issuances, and (ii) the volume and cost of inventory and commodity imbalances, our working capital deficit at March 31, 2018, was driven primarily by current maturities of long-term debt, with December 31, 2017, also impacted by short-term borrowings. We may have working capital deficits in future periods as we continue to finance our capital-growth projects and repay long-term debt, often initially with short-term borrowings. Our decision to utilize short-term borrowings rather than long-term debt, due to more favorable interest rates, may also contribute to our working capital deficit. We do not expect this working capital deficit to have an adverse impact to our cash flows or operations.

For additional information on our $2.5 Billion Credit Agreement and commercial paper program, see Note D of the Notes to Consolidated Financial Statements in this Quarterly Report.

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

Debt issuances and upcoming maturities - We expect to repay ONEOK Partners’ $425 million, 3.2 percent senior notes due in September 2018, with a combination of cash on hand and short-term borrowings.

Repayments - In January 2018, we repaid the remaining $500 million balance outstanding on the Term Loan Agreement due 2019 with a combination of cash on hand and short-term borrowings.

For additional information on our long-term debt, see Note D of the Notes to Consolidated Financial Statements in this Quarterly Report.

Equity issuances - In January 2018, we completed an underwritten public offering of 21.9 million shares of our common stock at a public offering price of $54.50 per share, generating net proceeds of $1.2 billion. We used the net proceeds from this offering to fund capital expenditures and for general corporate purposes, which included repaying a portion of our outstanding indebtedness. We have satisfied our expected equity financing needs through the remainder of 2018 and well into 2019.

In July 2017, we established an "at-the-market" equity program for the offer and sale from time to time of our common stock up to an aggregate amount of $1 billion. The program allows us to offer and sell our common stock at prices we deem appropriate through a sales agent. Sales of our common stock may 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 stock under the program. During the three months ended March 31, 2018, no shares were sold through our "at-the-market" equity program.

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

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Capital expenditures, excluding AFUDC and capitalized interest, were $264.5 million and $112.7 million for the three months ended March 31, 2018 and 2017, respectively.

We expect our total 2018 growth capital expenditures to range from $2.0 billion to $2.3 billion and our maintenance capital expenditures to range from $140 million to $180 million, excluding AFUDC and capitalized interest. See discussion of our announced capital-growth projects in the “Recent Developments” section.

Credit Ratings - Our long-term debt credit ratings as of April 23, 2018, are shown in the table below:

Rating Agency	Rating	Outlook
Moody’s	Baa3	Stable
S&P	BBB	Stable

Our commercial paper program is rated Prime-3 by Moody’s and A-2 by S&P.

Our credit ratings, which are investment grade, may be affected by a material change in our financial ratios or a material event affecting our business and industry. The most common criteria for assessment of our credit ratings are the debt-to-EBITDA ratio, interest coverage, business risk profile and liquidity. If our credit ratings were downgraded, our cost to borrow funds under our $2.5 Billion 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 $2.5 Billion Credit Agreement, which expires in 2022. An adverse credit rating change alone is not a default under our $2.5 Billion Credit Agreement. We do not expect a downgrade in our credit rating to have a material impact on our results of operations.

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

Dividends - Holders of our common stock share equally in any dividend declared by our board of directors, subject to the rights of the holders of outstanding preferred stock. In February 2018, we paid a quarterly dividend of $0.77 per share ($3.08 per share on an annualized basis), an increase of 25 percent compared with the same period in the prior year. Our dividend growth is due to the increase in cash flows resulting from the Merger Transaction and the continued growth of our operations. A dividend of $0.795 per share ($3.18 per share on an annualized basis) was declared for the shareholders of record at the close of business on April 30, 2018, payable May 15, 2018.

The Series E Preferred Stock pays quarterly dividends on each share of Series E Preferred Stock, when, as and if declared by our Board of Directors, at a rate of 5.5 percent per year. In February 2018, we paid dividends totaling $0.3 million for the Series E Preferred Stock. Dividends totaling $0.3 million were declared for the Series E Preferred Stock and are payable May 15, 2018.

In 2018, we expect our cash flows from operations to continue to sufficiently fund our cash dividends. For the three months ended March 31, 2018 and 2017, cash dividends paid to noncontrolling interests were sufficiently funded by cash flows from operations.

CASH FLOW ANALYSIS

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

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

	Three Months Ended March 31,		Variances 2018 vs. 2017 Favorable (Unfavorable)
	2018	2017	
	(Millions of dollars)		
Total cash provided by (used in):			
Operating activities	$495.3	$269.1	$ 226.2
Investing activities	(255.6)	(109.5)	(146.1)
Financing activities	(259.4)	(97.7)	(161.7)
Change in cash and cash equivalents	(19.7)	61.9	(81.6)
Cash and cash equivalents at beginning of period	37.2	248.9	(211.7)
Cash and cash equivalents at end of period	$17.5	$310.8	$ (293.3)

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

Cash flows from operating activities, before changes in operating assets and liabilities, increased to $444.6 million for the three months ended March 31, 2018, compared with $339.8 million for the same period in 2017. This increase is due primarily to higher earnings resulting from volume growth in the Williston Basin and STACK and SCOOP areas in our Natural Gas Gathering and Processing and Natural Gas Liquids segments and higher optimization and marketing earnings due primarily to wider location price differentials and the sale of NGL inventory previously held in our Natural Gas Liquids segment, as discussed in “Financial Results and Operating Information.”

The changes in operating assets and liabilities increased operating cash flows $50.7 million for the three months ended March 31, 2018, compared with a decrease of $70.7 million for the same period in 2017. This change is due primarily to the change in natural gas and NGLs in storage, which vary from period to period and vary with changes in commodity prices, and the change in accounts receivable, accounts payable, and other accruals and deferrals resulting from the timing of receipt of cash from customers and payments to vendors, suppliers and other third parties.

Investing Cash Flows - Cash used in investing activities for the three months ended March 31, 2018, increased $146.1 million compared with the same period in 2017, due primarily to increased capital expenditures related to our capital-growth projects.

Financing Cash Flows - Cash used in financing activities for the three months ended March 31, 2018, increased $161.7 million compared with the same period in 2017, due primarily to repayment of short-term borrowings and long-term debt and increased dividends, offset partially by the issuance of common stock through an underwritten public offering in January 2018.

REGULATORY, ENVIRONMENTAL AND SAFETY MATTERS

Regulatory - The Tax Cuts and Jobs Act makes extensive changes to the U.S. tax laws and includes provisions that reduce the U.S. corporate tax rate to 21 percent from 35 percent, increase expensing for capital investment, and limit the interest deduction and use of net operating losses to offset future taxable income. The Tax Cuts and Jobs Act may reduce future tariff rates charged on our regulated pipelines. The rates charged to our customers have generally been established through shipper specific negotiation, discounts and negotiated settlements, which do not ascribe any specific cost of service elements. We expect future tariff rate changes, if any, related to the change in the U.S. corporate tax rate to be established prospectively over time on a similar negotiated basis. We will continue to monitor applicable FERC rule-making, including the March 2018 notice of proposed rule-making on the impact of the Tax Cuts and Jobs Act on FERC-regulated rates for natural gas pipelines, which is subject to a public comment process prior to being finalized. If in the future the FERC or other regulatory bodies were to require us to establish a regulatory liability for amounts previously collected on our regulated pipelines, then we would expect to record a regulatory liability through a one-time charge to expense.

We also continue to monitor the FERC’s March 2018 revised policy statement for master limited partnerships, which no longer allows interstate natural gas and oil pipelines owned by master limited partnerships to recover an income tax allowance in cost

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of service rates. This revised policy remains pending at the FERC based on various requests for reconsideration or rehearing. We do not expect this FERC action to be material to our results of operations, as we are organized as a C-corporation. Further, regardless of organizational structure, we do not expect this FERC action to materially affect us, as the rates charged to our customers have generally been established through shipper specific negotiation, discounts and negotiated settlements, which do not ascribe any specific cost of service elements.

The FERC allows regulated NGL pipelines an annual index adjustment to transportation rates, which is intended to allow recovery of changes in costs without a complicated cost of service filing. The FERC is expected to evaluate how best to incorporate the effects of new tax policies in its next calculation of the rate index in 2020, for indexing effective July 2021. We do not expect to be materially impacted by any such change in the index calculation, as our regulated NGL pipeline revenues are primarily under negotiated agreements.

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

Additional information about our regulatory, environmental and safety matters can be found in “Regulatory, Environmental and Safety Matters” under Part I, Item 1, Business, in our Annual Report.

IMPACT OF NEW ACCOUNTING STANDARDS

See Note A of the Notes to Consolidated Financial Statements in this Quarterly Report for discussion of new accounting standards.

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.

Information about our estimates and critical accounting policies is included under Item 7, Management’s Discussion and Analysis of Financial Condition and Results of Operations, “Estimates and Critical Accounting Policies,” in our Annual Report.

FORWARD-LOOKING STATEMENTS

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

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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 Quarterly Report identified by words such as “anticipate,” “estimate,” “expect,” “project,” “intend,” “plan,” “believe,” “should,” “goal,” “guidance,” “could,” “may,” “continue,” “might,” “potential,” “scheduled” and other words and terms of similar meaning.

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

- the effects of weather and other natural phenomena, including climate change, on our operations, demand for our services and energy prices;
- competition from other United States and foreign energy suppliers and transporters, as well as alternative forms of energy, including, but not limited to, solar power, wind power, geothermal energy and biofuels such as ethanol and biodiesel;
- the capital intensive nature of our businesses;
- the profitability of assets or businesses acquired or constructed by us;
- our ability to make cost-saving changes in operations;
- risks of marketing, trading and hedging activities, including the risks of changes in energy prices or the financial condition of our counterparties;
- the uncertainty of estimates, including accruals and costs of environmental remediation;
- the timing and extent of changes in energy commodity prices;
- the effects of changes in governmental policies and regulatory actions, including changes with respect to income and other taxes, pipeline safety, environmental compliance, climate change initiatives and authorized rates of recovery of natural gas and natural gas transportation costs;
- the impact on drilling and production by factors beyond our control, including the demand for natural gas and crude oil; producers’ desire and ability to obtain necessary permits; reserve performance; and capacity constraints on the pipelines that transport crude oil, natural gas and NGLs from producing areas and our facilities;
- difficulties or delays experienced by trucks, railroads or pipelines in delivering products to or from our terminals or pipelines;
- changes in demand for the use of natural gas, NGLs and crude oil because of market conditions caused by concerns about climate change;
- the impact of unforeseen changes in interest rates, debt and equity markets, inflation rates, economic recession and other external factors over which we have no control, including the effect on pension and postretirement expense and funding resulting from changes in equity and bond market returns;
- our indebtedness and guarantee obligations 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 our credit;
- the results of administrative proceedings and litigation, regulatory actions, rule changes and receipt of expected clearances involving any local, state or federal regulatory body, including the FERC, the National Transportation Safety Board, the PHMSA, the EPA and CFTC;
- our ability to access capital at competitive rates or on terms acceptable to us;
- risks associated with adequate supply to our gathering, processing, fractionation and pipeline facilities, including production declines that outpace new drilling or extended periods of ethane rejection;
- the risk that material weaknesses or significant deficiencies in our internal controls over financial reporting could emerge or that minor problems could become significant;

- the impact and outcome of pending and future litigation;
- the ability to market pipeline capacity on favorable terms, including the effects of:
  - future demand for and prices of natural gas, NGLs and crude oil;
  - competitive conditions in the overall energy market;
  - availability of supplies of Canadian and United States natural gas and crude oil; and
  - availability of additional storage capacity;
- performance of contractual obligations by our customers, service providers, contractors and shippers;
- the timely receipt of approval by applicable governmental entities for construction and operation of our pipeline and other projects and required regulatory clearances;

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- our ability to acquire all necessary permits, consents or other approvals in a timely manner, to promptly obtain all necessary materials and supplies required for construction, and to construct gathering, processing, storage, fractionation and transportation facilities without labor or contractor problems;
- the mechanical integrity of facilities operated;
- demand for our services in the proximity of our facilities;
- our ability to control operating costs;
- acts of nature, sabotage, terrorism or other similar acts that cause damage to our facilities or our suppliers' or shippers' facilities;
- economic climate and growth in the geographic areas in which we do business;
- the risk of a prolonged slowdown in growth or decline in the United States or international economies, including liquidity risks in United States or foreign credit markets;
- the impact of recently issued and future accounting updates and other changes in accounting policies;
- the possibility of future terrorist attacks or the possibility or occurrence of an outbreak of, or changes in, hostilities or changes in the political conditions throughout the world;
- 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 our Annual Report and in our other filings that we make with the SEC, which are available via the SEC's website at www.sec.gov and our website at www.oneok.com. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these factors. Any such forward-looking statement speaks only as of the date on which such statement is made, and other than as required under securities laws, we undertake no obligation to update publicly any forward-looking statement whether as a result of new information, subsequent events or change in circumstances, expectations or otherwise.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our quantitative and qualitative disclosures about market risk are consistent with those discussed in Part II, Item 7A, Quantitative and Qualitative Disclosures about Market Risk, in our Annual Report.

COMMODITY PRICE RISK

As part of our hedging strategy, we use commodity derivative financial instruments and physical-forward contracts described in Note C of the Notes to Consolidated Financial Statements in this Quarterly Report to reduce the impact of near-term price fluctuations of natural gas, NGLs and condensate.

Although our businesses are primarily fee-based, in our Natural Gas Gathering and Processing segment, we are exposed to commodity price risk as a result of retaining a portion of the commodity sales proceeds associated with our POP with fee contracts. We have restructured a portion of our POP with fee contracts to include significantly higher fees, which reduces our equity volumes and the related commodity price exposure. However, under certain POP with fee contracts, our contractual fees and POP percentage may increase or decrease if production volumes, delivery pressures or commodity prices change relative to specified thresholds. We are exposed to basis risk between the various production and market locations where we buy and sell commodities.

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

	Nine Months Ending December 31, 2018		
	Volumes Hedged	Average Price	Percentage Hedged
NGLs - excluding ethane (MBbl/d) - Conway/Mont Belvieu	8.1	$0.66 / gallon	77%
Condensate (MBbl/d) - WTI-NYMEX	2.4	$52.84 / Bbl	79%
Natural gas (BBtu/d) - NYMEX and basis	67.1	$2.79 / MMBtu	89%

	Year Ending December 31, 2019		
	Volumes Hedged	Average Price	Percentage Hedged
NGLs - excluding ethane (MBbl/d) - Conway/Mont Belvieu	7.2	$0.71 / gallon	71%
Condensate (MBbl/d) - WTI-NYMEX	2.2	$56.90 / Bbl	65%

Our Natural Gas Gathering and Processing segment's commodity price sensitivity is estimated as a hypothetical change in the price of NGLs, crude oil and natural gas at March 31, 2018. Condensate sales are typically based on the price of crude oil. We estimate the following for our forecasted equity volumes, including the effects of hedging information set forth above, and assuming normal operating conditions:

- a $0.01 per-gallon change in the composite price of NGLs would change adjusted EBITDA for the nine months ending December 31, 2018, and for the year ending December 31, 2019, by approximately $1.8 million and $2.9 million, respectively;
- a $1.00 per-barrel change in the price of crude oil would change adjusted EBITDA for the nine months ending December 31, 2018, and for the year ending December 31, 2019, by approximately $0.3 million and $0.6 million, respectively; and
- a $0.10 per-MMBtu change in the price of residue natural gas would change adjusted EBITDA for the nine months ending December 31, 2018, and for the year ending December 31, 2019, by approximately $0.2 million and $2.8 million, respectively.

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

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

INTEREST-RATE RISK

We are exposed to interest-rate risk through our $2.5 Billion Credit Agreement, commercial paper program and long-term debt issuances. Future increases in LIBOR, corporate commercial paper rates or corporate bond rates could expose us to increased interest costs on future borrowings. We manage interest-rate risk through the use of fixed-rate debt, floating-rate debt and interest-rate swaps. Interest-rate swaps are agreements to exchange interest payments at some future point based on specified notional amounts. At March 31, 2018, and December 31, 2017, we had forward-starting interest-rate swaps with notional amounts totaling $2.0 billion and $1.3 billion, respectively, to hedge the variability of interest payments on a portion of our forecasted debt issuances. At December 31, 2017, we had interest-rate swaps with a notional amount totaling $500 million to hedge the variability of our LIBOR-based interest payments. All of our interest-rate swaps are designated as cash flow hedges. At March 31, 2018, we had derivative assets of $83.5 million and derivative liabilities of $11.2 million related to these interest-rate swaps. At December 31, 2017, we had derivative assets of $50.0 million related to these interest-rate swaps.

In January 2018, we settled the remaining $500 million of our interest-rate swaps used to hedge our LIBOR-based interest payments.

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

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COUNTERPARTY CREDIT RISK

We assess the creditworthiness of our counterparties on an ongoing basis and require security, including prepayments and other forms of collateral, when appropriate. Certain of our counterparties may be impacted by a relatively low commodity price environment and could experience financial problems, which could result in nonpayment and/or nonperformance, which could impact adversely our results of operations.

Customer concentration - For the three months ended March 31, 2018, no single customer represented more than 10 percent of our consolidated revenues.

Natural Gas Gathering and Processing - Our Natural Gas Gathering and Processing segment derives services revenue primarily from crude oil and natural gas producers, which include both large integrated and independent exploration and production companies. In this segment, our downstream commodity sales customers are primarily utilities, large industrial companies, marketing companies and our NGL affiliate. We are not typically exposed to material credit risk with producers under POP with fee contracts, as we sell the commodities and remit a portion of the sales proceeds back to the producer less our contractual fees. For the three months ended March 31, 2018 and 2017, approximately 90 percent and 99 percent, respectively, of the downstream commodity sales in our Natural Gas Gathering and Processing segment were made to investment-grade customers, as rated by S&P, Moody’s or our comparable internal ratings, or were secured by letters of credit or other collateral.

Natural Gas Liquids - Our Natural Gas Liquids segment’s counterparties are primarily NGL and natural gas gathering and processing companies; large integrated and independent crude oil and natural gas production companies; propane distributors; ethanol producers; and petrochemical, refining and NGL marketing companies. We charge fees to NGL and natural gas gathering and processing counterparties and natural gas liquids pipeline transportation customers. We are not typically exposed to material credit risk on the majority of our exchange services fees, as we purchase NGLs from our gathering and processing counterparties and deduct our fee from the amounts we remit. We earn sales revenue on the downstream sales of NGL products. For the three months ended March 31, 2018 and 2017, approximately 80 percent of this segment’s commodity sales were made to investment-grade customers, as rated by S&P, Moody’s or our comparable internal ratings, or were secured by letters of credit or other collateral. In addition, the majority of our Natural Gas Liquids segment’s pipeline tariffs provide us the ability to require security from shippers.

Natural Gas Pipelines - Our Natural Gas Pipelines segment’s customers are primarily local natural gas distribution companies, electric-generation facilities, large industrial companies, municipalities, producers and marketing companies. For the three months ended March 31, 2018 and 2017, approximately 90 percent and 85 percent, respectively, of our revenues in this segment were from investment-grade customers, as rated by S&P, Moody’s or our comparable internal ratings, or were secured by letters of credit or other collateral. In addition, the majority of our Natural Gas Pipelines segment’s pipeline tariffs provide us the ability to require security from shippers.

ITEM 4. CONTROLS AND PROCEDURES

Quarterly Evaluation of Disclosure Controls and Procedures - Our Chief Executive Officer (Principal Executive Officer) and Chief Financial Officer (Principal Financial Officer) 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.

Changes in Internal Control Over Financial Reporting - There have been no changes in our internal control over financial reporting during the quarter ended March 31, 2018, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II - OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Additional information about our legal proceedings is included in Note J of the Notes to Consolidated Financial Statements in this Quarterly Report and under Note O of the Notes to Consolidated Financial Statements in our Annual Report.

ITEM 1A. RISK FACTORS

Our investors should consider the risks set forth in Part I, Item 1A, Risk Factors, of our Annual Report 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

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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 discussion of risks and the other information included or incorporated by reference in this Quarterly Report, including "Forward-Looking Statements," which are included in Part I, Item 2, Management's Discussion and Analysis of Financial Condition and Results of Operations.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Not applicable.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not applicable.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

ITEM 5. OTHER INFORMATION

Not applicable.

ITEM 6. EXHIBITS

Readers of this report should not rely on or assume the accuracy of any representation or warranty or the validity of any opinion contained in any agreement filed as an exhibit to this Quarterly Report, because such representation, warranty or opinion may be subject to exceptions and qualifications contained in separate disclosure schedules, may represent an allocation of risk between parties in the particular transaction, may be qualified by materiality standards that differ from what may be viewed as material for securities law purposes, or may no longer continue to be true as of any given date. All exhibits attached to this Quarterly Report are included for the purpose of complying with requirements of the SEC. Other than the certifications made by our officers pursuant to the Sarbanes-Oxley Act of 2002 included as exhibits to this Quarterly Report, all exhibits are included only to provide information to investors regarding their respective terms and should not be relied upon as constituting or providing any factual disclosures about us, any other persons, any state of affairs or other matters.

The following exhibits are filed as part of this Quarterly Report:

Exhibit No.	Exhibit Description
3.1	Amended and Restated By-laws of ONEOK, Inc. (incorporated by reference from Exhibit 3.1 to ONEOK Inc.'s Current Report on Form 8-K filed February 22, 2017 (File No. 1-13643)).
3.2	Amended and Restated Certificate of Incorporation of ONEOK, Inc., dated July 3, 2017, as amended (incorporated by reference from Exhibit 3.2 to ONEOK Inc.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 2017, filed November 1, 2017 (File No. 1-13643)).
10.1	Underwriting Agreement, dated January 4, 2018, between ONEOK, Inc. and Credit Suisse Securities (USA) LLC, as representative of the several underwriters named therein (incorporated by reference to Exhibit 1.1 from ONEOK, Inc.'s Current Report on Form 8-K filed January 9, 2018 (File No. 1-13643)).

10.2	Form of 2018 Restricted Unit Award Agreement dated February 21, 2018 (incorporated by reference from Exhibit 10.17 to ONEOK Inc.'s Annual Report on Form 10-K filed February 27, 2018 (File No. 1-13643)).
10.3	Form of 2018 Performance Unit Award Agreement dated February 21, 2018 (incorporated by reference from Exhibit 10.18 to ONEOK Inc.'s Annual Report on Form 10-K filed February 27, 2018 (File No. 1-13643)).
31.1	Certification of Terry K. Spencer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Walter S. Hulse pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

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32.1	Certification of Terry K. Spencer pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished only pursuant to Rule 13a-14(b)).
32.2	Certification of Walter S. Hulse 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 Quarterly Report are the following XBRL-related documents: (i) Document and Entity Information; (ii) Consolidated Statements of Income for the three months ended March 31, 2018 and 2017; (iii) Consolidated Statements of Comprehensive Income for the three months ended March 31, 2018 and 2017; (iv) Consolidated Balance Sheets at March 31, 2018, and December 31, 2017; (v) Consolidated Statements of Cash Flows for the three months ended March 31, 2018 and 2017; (vi) Consolidated Statements of Changes in Equity for the three months ended March 31, 2018 and 2017; and (vii) Notes to Consolidated Financial Statements.

We also make available on our website the Interactive Data Files submitted as Exhibit 101 to this Quarterly Report.

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SIGNATURE

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

ONEOK, Inc.
Registrant

Date: May 2, 2018 By: /s/ Walter S. Hulse III
Walter S. Hulse III
Chief Financial Officer and
Executive Vice President, Strategic Planning
and Corporate Affairs
(Principal Financial Officer)