UNIT CORP
Form 10-K
February 26, 2019

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

FORM 10-K

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

For the fiscal year ended December 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: 1-9260

UNIT CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**73-1283193**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
8200 South Unit Drive, Tulsa, Oklahoma	**74132**
(Address of principal executive offices)	**(Zip Code)**

(Registrant's telephone number, including area code) (918) 493-7700

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

Title of each class	Name of each exchange on which registered
Common Stock, par value $.20 per share	NYSE

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes [x] No [ ]

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

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted 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 such files). Yes [x] No [ ]

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

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

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]
As of June 30, 2018, the aggregate market value of the voting and non-voting common equity (based on the closing price of the stock on the NYSE on June 30, 2018) held by non-affiliates was approximately $1,322,944,221. Determination of stock ownership by non-affiliates was made solely for the purpose of this requirement, and the registrant is not bound by these determinations for any other purpose.
Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding at February 12, 2019
Common Stock, $0.20 par value per share	54,366,397 shares

DOCUMENTS INCORPORATED BY REFERENCE

Document	Parts Into Which Incorporated
Portions of the registrant's definitive proxy statement (the Proxy Statement) with respect to its annual meeting of shareholders scheduled to be held on May 1, 2019. The Proxy Statement will be filed within 120 days after the end of the fiscal year to which this report relates.	Part III

Exhibit Index—See Page 135

FORM 10-K
UNIT CORPORATION

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The following are explanations of some terms used in this report.
ARO – Asset retirement obligations.
ASC – FASB Accounting Standards Codification.
ASU – Accounting Standards Update.
Bcf – Billion cubic feet of natural gas.
Bcfe – Billion cubic feet of natural gas equivalent. It is determined using the ratio of one barrel of crude oil or NGLs to six Mcf of natural gas.
Bbl – Barrel, or 42 U.S. gallons liquid volume.
Boe – Barrel of oil equivalent. Determined using the ratio of six Mcf of natural gas to one barrel of crude oil or NGLs.
BOKF – Bank of Oklahoma Financial Corporation.
Btu – British thermal unit, used in gas volumes. Btu is used to refer to the natural gas required to raise the temperature of one pound of water by one-degree Fahrenheit at one atmospheric pressure.
Development drilling – The drilling of a well within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.
DD&A – Depreciation, depletion, and amortization.
FASB – Financial and Accounting Standards Board.
Finding and development costs – Costs associated with acquiring and developing proved natural gas and oil reserves capitalized under generally accepted accounting principles, including any capitalized general and administrative expenses.
Gross acres or gross wells – The total acres or wells in which a working interest is owned.
IF – Inside FERC (U.S. Federal Energy Regulatory Commission).
LIBOR – London Interbank Offered Rate.
MBbls – Thousand barrels of crude oil or other liquid hydrocarbons.
Mcf – Thousand cubic feet of natural gas.
Mcfe – Thousand cubic feet of natural gas equivalent. It is determined using the ratio of one barrel of crude oil or NGLs to six Mcf of natural gas.
MMBbls – Million barrels of crude oil or other liquid hydrocarbons.
MMBoe – Million barrels of oil equivalents.
MMBtu – Million Btu’s.
MMcf – Million cubic feet of natural gas.
MMcfe – Million cubic feet of natural gas equivalent. It is determined using the ratio of one barrel of crude oil or NGLs to six Mcf of natural gas.
Net acres or net wells – The total fractional working interests owned in gross acres or gross wells.
NGLs – Natural gas liquids.
NYMEX – The New York Mercantile Exchange.
Play – A term applied by geologists and geophysicists identifying an area with potential oil and gas reserves.
Producing property – A natural gas or oil property with existing production.

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Proved developed reserves – Reserves expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and through installed extraction equipment and infrastructure operational at the time of the reserves estimate. For additional information, see the SEC's definition in Rule 4-10(a)(3) of Regulation S-X.

Proved reserves – Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs and under existing economic conditions, operating methods, and government regulations – before the time when the contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. For additional information, see the SEC's definition in Rule 4-10(a)(2)(i) through (iii) of Regulation S-X.

Proved undeveloped reserves – Proved reserves expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. For additional information, see the SEC's definition in Rule 4-10(a)(4) of Regulation S-X.

Reasonable certainty (regarding reserves) – If deterministic methods are used, reasonable certainty means high confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities recovered will equal or exceed the estimate.

Reliable technology – A grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

SARs – Stock appreciation rights.

Unconventional play – Plays targeting tight sand, carbonates, coal bed, or oil and gas shale reservoirs. The reservoirs tend to cover large areas and lack the readily apparent traps, seals, and discrete hydrocarbon-water boundaries that typically define conventional reservoirs. These reservoirs generally require horizontal wells and fracture stimulation treatments or other special recovery processes to produce economically.

Undeveloped acreage – Lease acreage on which wells have not been drilled or completed to the point that would permit the production of economic quantities of natural gas or oil regardless of whether the acreage contains proved reserves.

Well spacing – The regulation of the number and location of wells over an oil or gas reservoir, as a conservation measure. Well spacing is normally accomplished by order of the appropriate regulatory conservation commission.

Workovers – Operations on a producing well to restore or increase production.

WTI – West Texas Intermediate, the benchmark crude oil in the United States.

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UNIT CORPORATION
Annual Report
For The Year Ended December 31, 2018

PART I

Item 1. Business

Unless otherwise indicated or required by the context, the terms "Company," "Unit," "us," "our," "we," and "its" refer to Unit Corporation or, as appropriate, one or more of its subsidiaries. References to our mid-stream segment refer to Superior Pipeline Company, L.L.C. (and its subsidiaries) of which we own 50%.

Our executive offices are at 8200 South Unit Drive, Tulsa, Oklahoma 74132; our telephone number is (918) 493-7700.

Information regarding our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to these reports, will be provided free in print to any shareholders who request them. They are also available on our internet website at *www.unitcorp.com*, as soon as reasonably practicable after we electronically file these reports with or furnish them to the Securities and Exchange Commission (SEC). The SEC maintains an Internet website at *www.sec.gov* that contains reports, proxy and information statements, and other information about us that we file electronically with the SEC.

Also, we post on our Internet website, *www.unitcorp.com*, copies of our corporate governance documents. Our corporate governance guidelines and code of ethics, and the charters of our Board's Audit, Compensation, and Nominating and Governance Committees, are available for free on our website or in print to any shareholder who requests them. We may occasionally provide important disclosures to investors by posting them in the investor information section of our website, as allowed by SEC rules.

GENERAL

We were founded in 1963 as an oil and natural gas contract drilling company. Today, besides our drilling operations, we have operations in the exploration and production and mid-stream areas. We operate, manage, and analyze our results of operations through our three principal business segments:

- *Oil and Natural Gas* – carried out by our subsidiary Unit Petroleum Company. This segment explores, develops, acquires, and produces oil and natural gas properties for our account.
- *Contract Drilling* – carried out by our subsidiary Unit Drilling Company. This segment contracts to drill onshore oil and natural gas wells for others and our account.
- *Mid-Stream* – carried out by our subsidiary Superior Pipeline Company, L.L.C., and its subsidiaries (Superior). This segment buys, sells, gathers, processes, and treats natural gas for third parties and our account.

Each company may conduct operations through subsidiaries of its own.

This table provides certain information about us as of February 12, 2019:

Oil and Natural Gas	
Total number of wells in which we own	6,326

an interest	
Contract Drilling	
Total number of drilling rigs available for use	56
Mid-Stream	
Number of natural gas treatment plants we own	3
Number of processing plants we own	14
Number of natural gas gathering systems we own (1)	22

1.In 2018, two gathering systems were transferred to our oil and natural gas segment.

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2018 SEGMENT OPERATIONS HIGHLIGHTS

Oil and Natural Gas

Contract Drilling

- Utilization cycle during 2018:
  - Started the year with 31 drilling rigs operating;
  - Placed one new BOSS drilling rig into service in the third quarter and made modifications to nine SCR drilling rigs; and
  - Gradual increase in utilization through mid-year for a high of 36 drilling rigs operating at the end of July and we exited the year with 32 drilling rigs operating, following weaker commodity prices in the fourth quarter.
- All 11 BOSS drilling rigs were operating during the year.
- Average drilling rig dayrates increased 8% during the year.

Mid-Stream

- Sold 50% of the ownership interests for $300.0 million.
- Increased average processed gas volumes up to 158 MMcf per day during 2018 which represents approximately a 15% increase over 2017.
- Increased average gas liquids sold up to approximately 663,000 gallons per day during 2018 which is a 24% increase over 2017.
- Connected seven infill wells to our Pittsburgh Mills gathering system which increased gathered volume approximately 50 MMcf per day.
- Continued to expand the Cashion gathering and processing system in order to allow us to gather and process production from a new producer with a significant acreage dedication in the area.
- Connected 22 new wells to the Cashion system and started construction of a new plant and compressor station in order to increase our processing capacity up to 105 MMcf per day.
- Connected 13 new wells to our Hemphill processing facility and completed the construction project to upgraded compression facilities in the Buffalo Wallow area in order to handle additional volume.

FINANCIAL INFORMATION ABOUT SEGMENTS

See Note 18 of our Notes to Consolidated Financial Statements in Item 8 of this report for information regarding each of our segment’s revenues, profits or losses, and total assets.

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OIL AND NATURAL GAS

General. All our oil and natural gas properties are in the United States. Our producing oil and natural gas properties, unproved properties, and related assets are in Oklahoma, Texas, Kansas, Arkansas, Colorado, Wyoming, Montana, North Dakota, and Utah.

When we are the operator of a property, we try to drill wells using a drilling rig owned by our contract drilling segment, and we use our mid-stream segment to gather our gas if it is economical to do so.

This table presents certain information regarding our oil and natural gas operations as of December 31, 2018:

	Number of Gross Wells	Number of Net Wells	Number of Gross Wells in Process	Number of Net Wells in Process	2018 Average Net Daily Production		
					Natural Gas (Mcf)	Oil (Bbls)	NGLs (Bbls)
Total	6,322	2,337.98	49	6.00	152,398	7,874	13,494

As of December 31, 2018, we had no significant water floods, pressure maintenance operations, or any other material related activities in process.

Acquisitions. On April 3, 2017, we closed an acquisition of certain oil and natural gas assets located primarily in Grady and Caddo Counties in western Oklahoma. The final adjusted value of consideration given was $54.3 million. As of January 1, 2017, the effective date of the acquisition, the estimated proved oil and gas reserves of the acquired properties were 3.2 million barrels of oil equivalent (MMBoe). The acquisition added approximately 8,300 net oil and gas leasehold acres to our core Hoxbar area in southwestern Oklahoma including approximately 47 proved developed producing wells. This acquisition included 13 potential horizontal drilling locations not otherwise included in our existing acreage. Of the acreage acquired, approximately 71% was held by production. We also received one gathering system as part of the transaction.

In December 2018, we closed on an acquisition of certain oil and natural gas assets located primarily in Custer County, Oklahoma. The total preliminary adjusted value of consideration was $29.6 million. As of November 1, 2018, the effective date of the acquisition, the estimated proved oil and gas reserves for the acquired properties was 2.6 MMBoe net to us. The acquisition added approximately 8,667 net oil and gas leasehold acres to our Penn Sands area in Oklahoma including approximately 44 wells. The acquisitions included approximately 30 potential horizontal drilling locations which are anticipated to have a high percentage of oil relative to the total production stream. Of the acreage acquired, approximately 82% was held by production.

Dispositions. We had non-core asset sales, net of related expenses, of $22.5 million, $18.6 million, and $67.2 million, in 2018, 2017, and 2016, respectively. Proceeds from these sales reduced the net book value of the full cost pool with no gain or loss recognized.

During prior years, we determined the value of some of our unproved oil and gas properties were diminished (in part or whole) based on an impairment evaluation and our anticipated future exploration plans. Those determinations resulted in $7.6 million and $10.5 million in 2016 and 2017, respectively, of costs being added to the total of our capitalized costs being amortized. We incurred a $161.6 million pre-tax ($100.6 million net of tax) non-cash ceiling test write-down of our oil and natural gas properties in 2016 primarily due to the reduction of the 12-month average commodity prices during the first three quarters of the year. We had no ceiling test write-downs for 2017 or 2018.

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Well and Leasehold Data. These tables identify certain information regarding our oil and natural gas exploratory and development drilling operations:

	Year Ended December 31,					
	2018		2017		2016	
	Gross	Net	Gross	Net	Gross	Net
Wells drilled:						
Development:						
Oil	52	9.18	45	10.98	9	3.57
Natural Gas	63	22.96	23	13.90	11	5.10
Dry	2	1.02	2	0.83	—	—
Total development	117	33.16	70	25.71	20	8.67
Exploratory:						
Oil	—	—	—	—	1	1.00
Natural gas	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total exploratory	—	—	—	—	1	1.00
Total wells drilled	117	33.16	70	25.71	21	9.67

	Year Ended December 31,					
	2018 (1)		2017		2016 (2)	
	Gross	Net	Gross	Net	Gross	Net
Wells producing or capable of producing:						
Oil	1,533	598.50	1,554	632.85	1,574	634.56
Natural gas	4,775	1,734.96	4,887	1,797.66	4,944	1,770.43
Total	6,308	2,333.46	6,441	2,430.51	6,518	2,404.99

1.There were 56 gross wells with multiple completions.

2.During 2016, we divested 1,300 gross (407.70 net) wells. There were no significant divestitures in 2017 or 2018.

As of February 12, 2019, we were involved in drilling nine gross (4.54 net) wells started during 2019.

Cost for development drilling includes $76.3 million, $41.6 million, and $2.5 million in 2018, 2017, and 2016, respectively, to develop previously booked proved undeveloped oil and natural gas reserves.

This table summarizes our leasehold acreage at December 31, 2018:

	Year Ended December 31, 2018					
	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net (1)	Gross	Net
Total	561,687	387,176	127,834	81,139	689,521	468,315

1.Approximately 76% of the net undeveloped acres are covered by leases that will expire in the years 2019—2021 unless drilling or production extends the terms of those leases. Currently, we do not have any material proved undeveloped (PUD) reserves attributable to acreage where the expiration date precedes the scheduled PUD reserve development plan.

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Price and Production Data. The following tables identify the average sales price, production volumes, and average production cost per equivalent barrel for our oil, NGLs, and natural gas production for the years indicated:

	Year Ended December 31,					
	2018		2017		2016	
Average sales price per barrel of oil produced:						
Price before derivatives	$	63.78	$	48.98	$	39.05
Effect of derivatives	(8.00)		0.46		1.45	
Price including derivatives	$	55.78	$	49.44	$	40.50
Average sales price per barrel of NGLs produced:						
Price before derivatives	$	22.58	$	18.35	$	11.26
Effect of derivatives	(0.40)		—		—	
Price including derivatives	$	22.18	$	18.35	$	11.26
Average sales price per Mcf of natural gas produced:						
Price before derivatives	$	2.42	$	2.49	$	1.98
Effect of derivatives	0.04		(0.03)		0.09	
Price including derivatives	$	2.46	$	2.46	$	2.07

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	Year Ended December 31,		
	2018	2017	2016
Oil production (MBbls):			
Jazz Wilcox field	418	533	589
Buffalo Wallow field	258	127	120
All other fields	2,198	2,055	2,265
Total oil production	2,874	2,715	2,974
NGLs production (MBbls):			
Jazz Wilcox field	1,370	1,567	1,671
Buffalo Wallow field	1,235	728	592
All other fields	2,320	2,442	2,751
Total NGLs production	4,925	4,737	5,014
Natural gas production (MMcf):			
Jazz Wilcox field	17,494	16,799	18,145
Buffalo Wallow field	9,428	6,228	5,506
All other fields	28,704	28,233	32,084
Total natural gas production	55,626	51,260	55,735
Total production (MBoe):			
Jazz Wilcox field	4,703	4,900	5,284
Buffalo Wallow field	3,065	1,893	1,629
All other fields	9,302	9,203	10,364
	17,070	15,996	17,277

Total production						
Average production cost per equivalent Bbl [1]	$	6.50	$	6.24	$	5.31

1.Excludes ad valorem taxes and gross production taxes.

Our Buffalo Wallow field in Hemphill County, Texas, contained 29%, 24%, and 13% of our total proved reserves in 2018, 2017, and 2016, respectively, expressed on an oil-equivalent barrels basis. Our Jazz Wilcox field in South Texas, which includes our Gilly, Segno, and Wildwood prospects and several smaller prospects, contained 14%, 18%, and 26% of our total proved reserves for those same years also expressed on an oil-equivalent barrels basis. There are no other fields that accounted for more than 15% of our proved reserves.

Oil, NGLs, and Natural Gas Reserves. The following table identifies our estimated proved developed and undeveloped oil, NGLs, and natural gas reserves:

	Year Ended December 31, 2018			
	Oil (MBbls)	**NGLs (MBbls)**	**Natural Gas (MMcf)**	**Total Proved Reserves (MBoe)**
Total proved developed	15,192	33,515	377,216	111,576
Total proved undeveloped	7,366	14,281	158,747	48,105
Total proved	22,558	47,796	535,963	159,681

Oil, NGLs, and natural gas reserves cannot be measured exactly. Estimates of those reserves require extensive judgments of reservoir engineering data and are generally less precise than other estimates made in financial disclosures. We use Ryder Scott Company, L.P., (Ryder Scott), independent petroleum consultants, to audit the reserves prepared by our reservoir engineers. Ryder Scott has been providing petroleum consulting services throughout the world since 1937. Their summary report is attached as Exhibit 99.1 to this Form 10-K. The wells or locations for which reserve estimates were audited were taken from our reserve and income projections as of December 31, 2018, and comprised 83% of the total proved developed future net income discounted at 10% and 82% of the total proved discounted future net income (based on the SEC's unescalated pricing policy).

Our Reservoir Engineering department is responsible for reserve determination for the wells in which we have an interest. Their primary objective is to estimate the wells' future reserves and future net value to us. Data is incorporated from multiple

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sources including geological, production engineering, marketing, production, land, and accounting departments. The engineers review this information for accuracy as it is incorporated into the reservoir engineering database. Our internal audit group reviews our internal controls to help provide assurance all the data has been provided. New well reserve estimates are provided to management and the respective operational divisions for additional scrutiny. Major reserve changes on existing wells are reviewed regularly with the operational divisions to confirm completeness and accuracy. As the external audit is being completed by Ryder Scott, the reservoir department reviews all properties for accuracy of forecasting.

Technical Qualifications

Ryder Scott – Mr. Robert J. Paradiso was the primary technical person responsible for overseeing the estimate of the reserves, future production and income prepared by Ryder Scott.

Mr. Paradiso, an employee of Ryder Scott since 2008, is a Vice President and serves as Project Coordinator, responsible for coordinating and supervising staff and consulting engineers in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Paradiso served in several engineering positions with Getty Oil Company, Texaco, Union Texas Petroleum, Amax Oil and Gas, Inc., Norcen Explorer, Inc., Amerac Energy Corporation, Halliburton Energy Services, Santa Fe Snyder Corp., and Devon Energy Corporation.

Mr. Paradiso earned a Bachelor of Science degree in Petroleum Engineering from Texas Tech University in 1979 and is a registered Professional Engineer in the State of Texas. He is also a member of the Society of Petroleum Engineers (SPE).

Besides gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires at least fifteen hours of continuing education annually, including at least one hour in professional ethics, which Mr. Paradiso fulfills. As part of his 2018 continuing education hours, Mr. Paradiso attended 6 hours of formalized training during the 2018 RSC Reserves Conference relating to the definitions and disclosure guidelines in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register. Mr. Paradiso attended an additional 20.8 hours of formalized in-house training during 2018 covering such topics as the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, reservoir engineering, geoscience and petroleum economics evaluation methods, procedures and software and ethics for consultants.

Based on his educational background, professional training and over 39 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Paradiso has attained the professional qualifications as a Reserves Estimator and Reserves Auditor in Article III of the “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information” promulgated by the SPE as of February 19, 2007. For more information regarding Mr. Paradiso’s geographic and job-specific experience, please refer to the Ryder Scott Company website at http://www.ryderscott.com/Company/Employees.

The Company – Responsibility for overseeing the preparation of our reserve report is shared by our reservoir engineers Trenton Mitchell and Derek Smith.

Mr. Mitchell earned a Bachelor of Science degree in Petroleum Engineering from Texas A&M University in 1994. He has been an employee of Unit since 2002. Initially, he was the Outside Operated Engineer and since 2003 he has served in the capacity of Reservoir Engineer and in 2010 he was promoted to Manager of Reservoir Engineering. Before joining Unit, he served in several engineering field and technical support positions with Schlumberger Well Services in their pumping services segment (formerly Dowell Schlumberger). He obtained his Professional Engineer registration from the State of Oklahoma in 2004. He has been a member of SPE since 1991 and joined the Society of

Petroleum Evaluation Engineers (SPEE) in 2017.

Mr. Smith received a Bachelor of Science in Petroleum Engineering with a Minor in Business from the University of Tulsa in 2005. He worked for Apache Corporation immediately after in Production Engineering, then Reservoir Engineering, followed by Drilling Engineering for approximately one year each before moving to Corporate Reserves in 2008. He joined Unit in 2009 as a Corporate Reserves Engineer involved in reserve evaluation, acquisition appraisals, and prospect reviews with increasing levels of responsibility. He has been a member of SPE since 2000 and joined the SPEE in 2018.

As part of their continuing education Mr. Mitchell and Mr. Smith have attended various seminars and forums to enhance their understanding of current standards and issues for reserves presentation. These forums have included those sponsored by various professional societies and professional service firms including Ryder Scott.

Definitions and Other. Proved oil, NGLs, and natural gas reserves, as defined in SEC Rule 4-10(a), are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be

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economically producible – from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations – before the time the contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

The area of the reservoir considered as "proved" includes:

•The area identified by drilling and limited by any fluid contacts, and
•Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with the reservoir and to contain economically producible oil or gas based on available geosciences and engineering data.

Absent data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as incurred in a well penetration unless geosciences, engineering, or performance data and reliable technology establish a lower contact with reasonable certainty.

Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geosciences, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

•Successful testing by a pilot project in an area of the reservoir with properties no more favorable than the reservoir as a whole;
•The operation of an installed program in the reservoir or other evidence using reliable technology establishes reasonable certainty of the engineering analysis on which the project or program was based; and
•The project has been approved for development by all necessary parties and entities, including governmental entities.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price used is the average of the prices over the 12 months before the ending date of the period covered by the report and is an unweighted arithmetic average of the first day of the month price for each month within the period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions.

"Proved developed" oil, NGLs, and natural gas reserves are proved reserves expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor to the cost of a new well. It can also be recovered through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

"Proved undeveloped" oil, NGLs, and natural gas reserves are proved reserves expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for completion. Reserves on undrilled acreage are limited to those directly offsetting development spacing areas reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time. Under no circumstances can estimates for proved undeveloped reserves be attributable to acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless those techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

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Proved Undeveloped Reserves. As of December 31, 2018, we had 158 gross proved undeveloped wells all of which we plan to develop within five years of initial disclosure at a net estimated cost of approximately $397.4 million. The future estimated development costs to develop our proved undeveloped oil and natural gas reserves for the years 2019-2023, as disclosed in our December 31, 2018 oil and natural gas reserve report, are shown below:

Year	Number of Gross Wells Planned	Estimated Net Development Cost (In millions)	
2019	73	$	104.2
2020	47	135.8	
2021	26	97.6	
2022	10	48.8	
2023	2	11.0	
	158	$	397.4

Our proved undeveloped reserves reported at December 31, 2018 did not include reserves we did not expect to develop within five years of initial disclosure of those reserves. Below, we summarize changes to our proved undeveloped reserves during 2018:

	Oil (MMBbls)	NGLs (MMBbls)	Natural Gas (Bcf)	Total (MMBoe)
Proved undeveloped reserves, January 1, 2018	4.7	12.1	120.2	36.8
Extensions and discoveries	3.3	4.6	59.4	17.8
Converted to developed	(1.6)	(2.3)	(17.3)	(6.8)
Revisions of previous estimates	0.4	(0.5)	(6.2)	(1.1)
Purchases of reserves	0.6	0.4	2.6	1.4
Proved undeveloped reserves, December 31, 2018	7.4	14.3	158.7	48.1

During 2018, we converted 18 proved undeveloped well locations into proved developed wells at a cost of approximately $76.3 million. The increase in the table above to our extensions and discoveries were due to several factors including increased drilling activity, higher commodity prices resulting in an increased budget for future capital expenditures, all contributing to more wells being economical to develop in the next five years.

Our estimated proved reserves and the standardized measure of discounted future net cash flows of the proved reserves at December 31, 2018, 2017, and 2016, the changes in quantities, and standardized measure of those reserves for the three years then ended, are shown in the Supplemental Oil and Gas Disclosures in Item 8 of this report.

Contracts. Our oil production is sold at or near our wells under purchase contracts at prevailing prices under arrangements customary in the oil industry. Our natural gas production is sold to intrastate and interstate pipelines and independent marketing firms under contracts with terms generally ranging from one month to a year. Few of these contracts contain provisions for readjustment of price as most are market sensitive.

Customers. During 2018, sales to CVR Refining, LP and Valero Energy Corporation accounted for 14% and 10% of our oil and natural gas revenues, respectively. Besides our mid-stream segment, no other company accounted for over 10% of our oil and natural gas revenues. During 2018, our mid-stream segment purchased $81.4 million of our natural gas and NGLs production and provided gathering and transportation services of $7.3 million. Intercompany revenue from services and purchases of production between our mid-stream segment and our oil and natural gas segment has been eliminated in our consolidated financial statements. In 2017 and 2016, we eliminated intercompany revenues of $69.9 million and $51.9 million, respectively, attributable to the intercompany purchase of our production of natural gas and NGLs and gathering and transportation services.

CONTRACT DRILLING

General. Our contract drilling business is conducted through Unit Drilling Company. Through this company we drill onshore oil and natural gas wells for our account and others. Our drilling operations are in Oklahoma, Texas, Colorado, Wyoming, Utah, and North Dakota.

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This table identifies certain information about our contract drilling segment:

	Year Ended December 31,		
	2018	2017	2016
Number of drilling rigs available for use at year end [1]	55.0	95.0	94.0
Average number of drilling rigs owned during the year	95.5	94.5	93.9
Average number of drilling rigs utilized	32.8	30.0	17.4
Utilization rate [2]	34 %	32 %	19 %
Average revenue per day [3]	$ 16,429	$ 15,934	$ 19,154
Total footage drilled (feet in 1,000's)	8,386	6,864	5,112
Number of wells drilled	539	468	358

1.In December 2018, we removed from service 41 drilling rigs, tubulars, hydraulic top drives, mud pumps, and other drilling equipment.
2.Utilization rate is determined by dividing the average number of drilling rigs used by the average number of drilling rigs owned during the year.
3.Represents the total revenues from our contract drilling segment divided by the total days our drilling rigs were used during the year.

Description and Location of Our Drilling Rigs. An on-shore drilling rig is composed of major equipment components like engines, drawworks or hoists, derrick or mast, substructure, mud pumps, blowout preventers, top drives, and drill pipe. Because of the normal wear and tear from operating 24 hours a day, several of the major components, like engines, mud pumps, top drives, and drill pipe, must be replaced or rebuilt periodically. Other major components, like the substructure, mast, and drawworks, can be used for extended periods with proper maintenance. We also own additional equipment used in operating our drilling rigs, including iron roughnecks, automated catwalks, skidding systems, large air compressors, trucks, and other support equipment. Our drilling rigs can be transferred between divisions.

The maximum depth capacities of our various drilling rigs range from 9,500 to 40,000 feet allowing us to cover a wide range of our customers drilling requirements. In 2018, 38 of our 55 drilling rigs were used in drilling services.

This table shows certain information about our drilling rigs as of February 12, 2019:

Contracted Rigs	Non-Contracted Rigs	Total Rigs	Average Rated Drilling Depth

				(ft)
Drilling Rigs	30	26	56	20,196

Fluctuating commodity prices directly affect drilling rig utilization rates, both positively and negatively. We saw this during 2018 as commodity prices improved from the fourth quarter of 2017 through the middle of 2018, so did drilling rig utilization. Commodity prices then declined in the fourth quarter of 2018 and rig utilization followed.

At any given time the number of drilling rigs we can work depends on several conditions besides demand, including the availability of qualified labor and the availability of needed drilling supplies and equipment. The impact of these conditions affects the demand for our drilling rigs. Our average utilization rate for 2018, 2017, and 2016 was 34%, 32%, and 19%, respectively.

The following table shows the average number of our drilling rigs working by quarter for the years indicated:

	2018	**2017**	**2016**
First quarter	31.7	25.5	20.6
Second quarter	32.2	28.8	13.5
Third quarter	34.2	34.6	16.0
Fourth quarter	33.1	31.2	19.5

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Drilling Rig Fleet. The following table summarizes the changes to our drilling rig fleet in 2018. A more complete discussion of changes over the last three years follows the table:

Drilling rigs available for use on January 1, 2018	95
Drilling rigs removed from service (1)	(41)
Drilling rigs constructed	1
Total drilling rigs available for use on December 31, 2018	55

1.In December 2018, we removed from service 41 drilling rigs, tubulars, hydraulic top drives, mud pumps, and other drilling equipment.

Dispositions, Acquisitions, and Construction. During December 2016, we sold an idle 1,500 horsepower SCR drilling rig to an unaffiliated third party. We also built and placed into service for a third party operator our ninth BOSS drilling rig.

During 2017, we built our tenth BOSS drilling rig and placed it into service for a third party operator under a long term contract.

During 2018, we built our eleventh BOSS drilling rig and placed it into service for a third party operator under a long term contract.

In December 2018, our Board of Directors approved a plan to sell 41 drilling rigs (29 mechanical drilling rigs and 12 SCR diesel-electric drilling rigs) and other equipment. This plan satisfies the criteria of assets held for sale under ASC 360-10-45-9. Over the last five years, only six of our drilling rigs in the fleet have not been utilized. We made a strategic decision to focus on our new BOSS drilling rigs and specific SCR drilling rigs (good candidates for modification) and sell the other drilling rigs that we now choose not to market. We estimated the fair value of the 41 drilling rigs we will no longer market based on the estimated market value from third-party assessments (Level 3 fair value measurement) less cost to sell. Based on these estimates, we recorded a non-cash write-down of approximately $147.9 million, pre-tax ($111.7 million, net of tax).

Drilling Contracts. Our drilling contracts are generally obtained through competitive bidding on a well by well basis. Contract terms and payment rates vary depending on the type of contract used, the duration of the work, the equipment and services supplied, and other matters. We pay certain operating expenses, including the wages of our drilling rig personnel, maintenance expenses, and incidental drilling rig supplies and equipment. The contracts are usually subject to early termination by the customer subject to the payment of a fee. Our contracts also contain provisions regarding indemnification against certain types of claims involving injury to persons, property, and for acts of pollution. The specific terms of these indemnifications are negotiable on a contract by contract basis.

The type of contract used determines our compensation. All of our contracts in 2018, 2017, and 2016 were daywork contracts. Under a daywork contract, we provide the drilling rig with the required personnel and the operator supervises the drilling of the well. Our compensation is based on a negotiated rate to be paid for each day the drilling rig is used.

The majority of our contracts are on a well-to-well basis, with the rest under term contracts. Term contracts range from six months to three years and the rates can either be fixed throughout the term or allow for periodic adjustments.

Customers. During 2018, QEP Resources, Inc. and Slawson Exploration Company, Inc. were our largest third-party drilling customers accounting for approximately 16% and 10% of our total contract drilling revenues, respectively. Our work for this customer was under multiple contracts and our business was not substantially dependent on a single contract. None of these individual contracts were considered material. No other third-party customer accounted for 10% or more of our contract drilling revenues.

Our contract drilling segment also provides drilling services for our oil and natural gas segment. During 2018, 2017, and 2016, our contract drilling segment drilled 45, 27, and ten wells, respectively, for our oil and natural gas segment, or 8%, 6%, and 3%, respectively, of the total wells drilled by our contract drilling segment. Depending on the timing of the drilling services performed on our properties those services may be deemed, for financial reporting purposes, to be associated with acquiring an ownership interest in the property. Revenues and expenses for these services are eliminated in our statement of operations, with any profit recognized reducing our investment in our oil and natural gas properties. The contracts for these services are issued under similar terms and rates as the contracts signed with unrelated third parties. By providing drilling services for the oil and natural gas segment, we eliminated revenue of $22.5 million and $13.4 million during 2018 and 2017, respectively, from our contract drilling segment and eliminated the associated operating expense of $19.5 million and $11.8 million during 2018 and

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2017, respectively, yielding $3.0 million and $1.6 million during 2018 and 2017, respectively, as a reduction to the carrying value of our oil and natural gas properties. We eliminated no revenue or expenses in our contract drilling segment during 2016.

MID-STREAM

General. Our mid-stream operations are conducted through Superior Pipeline Company, L.L.C. and its subsidiaries. Its operations consist of buying, selling, gathering, processing, and treating natural gas. It operates three natural gas treatment plants, 14 processing plants, 22 active gathering systems, and approximately 1,475 miles of pipeline. Superior and its subsidiaries operate in Oklahoma, Texas, Kansas, Pennsylvania, and West Virginia. We own 50% of Superior.

This table presents certain information regarding our mid-stream segment for the years indicated:

	Year Ended December 31,		
	2018	**2017**	**2016**
Gas gathered—Mcf/day	393,613	385,209	419,217
Gas processed—Mcf/day	158,189	137,625	155,461
NGLs sold—gallons/day	663,367	534,140	536,494

Dispositions and Acquisitions. This segment had no significant dispositions or acquisitions during 2016 or 2017.

On April 3, 2018, we sold 50% of the ownership interest in our mid-stream segment, Superior. The purchaser is SP Investor Holdings, LLC, a holding company jointly owned by OPTrust and funds managed and/or advised by Partners Group, a global private markets investment manager. We received $300.0 million from this sale. A portion of the proceeds were used to pay down our bank debt and the remainder were used to accelerate the drilling program of our upstream subsidiary, Unit Petroleum Company and build additional BOSS drilling rigs. In connection with the sale of the interest in Superior, we took the necessary actions under the Indenture governing our outstanding senior subordinated notes to secure the ability to close the sale and have Superior released from the Indenture.

Superior will be governed and managed under its Amended and Restated Limited Liability Company Agreement and the Master Services and Operating Agreement (MSA) signed by Superior and an affiliate of Unit, as both agreements may be amended occasionally. Further details are in Note 16 – Variable Interest Entity Arrangements.

Contracts. Our mid-stream segment provides its customers with a full range of gathering, processing, and treating services. These services are usually provided to each customer under long-term contracts (more than one year), but we have short-term contracts. Our customer agreements include these types of contracts:

•*Fee-Based Contracts.* These contracts provide for a set fee for gathering, transporting, compressing, and treating services. Our mid-stream's revenue is a function of the volume of natural gas and is not directly dependent on the value of natural gas. For the year ended December 31, 2018, 67% of our mid-stream segment's total volumes and 61% of its operating margins (as defined below) were under fee-based contracts.
•*Commodity-Based Contracts.* These contracts consist of several contract structure types. Under these contract structures, our mid-stream segment purchases the raw well-head natural gas and settles with the producer at a stipulated price while retaining all sales proceeds from third parties or retains a negotiated percentage of the sales proceeds from the residue natural gas and NGLs it gathers and processes, with the remainder being paid to the producer. For the year ended December 31, 2018, 33% of our mid-stream segment's total volumes and 39% of

operating margins (as defined below) were under commodity-based contracts.

For each of the above contracts, operating margin is defined as total operating revenues less operating expenses and does not include depreciation, amortization, and impairment, general and administrative expenses, interest expense, or income taxes.

Customers. During 2018, ONEOK, Inc. accounted for approximately 45% of our mid-stream revenues. We believe that if we lost this customer, there are other customers available to purchase our gas and NGLs. During 2018, 2017, and 2016 our mid-stream segment purchased $81.4 million, $63.2 million, and $42.7 million, respectively, of our oil and natural gas segment's natural gas and NGLs production, and provided gathering and transportation services of $7.3 million, $6.7 million, and $9.2 million, respectively. Intercompany revenue from services and purchases of production between this business segment and our oil and natural gas segment has been eliminated in our consolidated financial statements.

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VOLATILE NATURE OF OUR BUSINESS

The prevailing prices for oil, NGLs, and natural gas significantly affect our revenues, operating results, cash flow, and our ability to grow our operations. Oil, NGLs, and natural gas prices have been volatile, and they will probably continue to be so. For each period indicated, this table shows the highest and lowest average prices our oil and natural gas segment received for its sales of oil, NGLs, and natural gas without considering the effect of derivatives:

	Oil Price per Bbl		NGLs Price per Bbl		Natural Gas Price per Mcf	
Quarter	**High**	**Low**	**High**	**Low**	**High**	**Low**
2016						
First	$ 31.49	$ 26.62	$ 9.49	$ 4.54	$ 1.86	$ 1.20
Second	$ 45.13	$ 36.63	$ 13.19	$ 8.61	$ 1.52	$ 1.36
Third	$ 41.75	$ 41.40	$ 14.95	$ 9.87	$ 2.48	$ 2.32
Fourth	$ 48.80	$ 42.71	$ 19.07	$ 12.14	$ 2.85	$ 2.25
2017						
First	$ 50.48	$ 46.85	$ 20.71	$ 15.04	$ 3.76	$ 2.14
Second	$ 48.73	$ 43.49	$ 15.33	$ 14.36	$ 2.95	$ 2.30
Third	$ 49.66	$ 44.54	$ 19.99	$ 16.17	$ 2.53	$ 2.04
Fourth	$ 57.38	$ 49.62	$ 22.39	$ 21.13	$ 2.58	$ 1.93
2018						
First	$ 63.04	$ 58.74	$ 22.52	$ 20.03	$ 2.92	$ 2.08
Second	$ 68.61	$ 65.76	$ 23.46	$ 21.14	$ 2.23	$ 1.96
Third	$ 70.75	$ 68.38	$ 29.61	$ 25.15	$ 2.28	$ 2.19
Fourth	$ 69.88	$ 47.54	$ 25.12	$ 16.32	$ 3.72	$ 2.25

Prices for oil, NGLs, and natural gas are subject to wide fluctuations in response to relatively minor changes in the actual or perceived supply of and demand for oil and natural gas, market uncertainty, and many additional factors beyond our control, including:

- political conditions in oil producing regions;
- the ability of the members of the Organization of Petroleum Exporting Countries (OPEC) and Russia to agree on prices and their ability or willingness to maintain production quotas;
- actions taken by foreign oil and natural gas producing nations;
- the price of foreign oil imports;
- imports and exports of oil and liquefied natural gas;
- actions of governmental authorities;
- the domestic and foreign supply of oil, NGLs, and natural gas;
- the level of consumer demand;
- United States storage levels of oil, NGLs, and natural gas;
- weather conditions;
- domestic and foreign government regulations;
- the price, availability, and acceptance of alternative fuels;
- volatility in ethane prices causing rejection of ethane as part of the liquids processed stream; and
- worldwide economic conditions.

These factors and the volatile nature of the energy markets make it impossible to predict with any certainty the future prices of oil, NGLs, and natural gas. You are encouraged to read the Risk Factors discussed in Item 1A of this report for additional risks that can affect our operations.

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Our contract drilling operations depend on the level of demand in our operating markets. Both short-term and long-term trends in oil, NGLs, and natural gas prices affect demand. Because oil, NGLs, and natural gas prices are volatile, the level of demand for our services is also volatile.

Our mid-stream operations provide us greater flexibility in delivering our (and third parties) natural gas and NGLs from the wellhead to major natural gas and NGLs pipelines. Margins received for the delivery of these natural gas and NGLs depend on the price for oil, NGLs, and natural gas and the demand for natural gas and NGLs in our area of operations. If the price of NGLs falls without a corresponding decrease in the cost of natural gas, it may become uneconomical to us to extract certain NGLs. The volumes of natural gas and NGLs processed depend highly on the volume and Btu content of the natural gas and NGLs gathered.

COMPETITION

All of our businesses are highly competitive and price sensitive. Competition in the contract drilling business traditionally involves factors such as demand, price, efficiency, the condition of equipment, availability of labor and equipment, reputation, and customer relations.

Our oil and natural gas operations likewise encounter strong competition from other oil and natural gas companies. Many competitors have greater financial, technical, and other resources than we do and have more experience than we do in the exploration for and production of oil and natural gas.

Our drilling success and the success of other activities integral to our operations will depend, in part, during times of increased competition on our ability to attract and retain experienced geologists, engineers, and other professionals. Competition for these professionals can be intense.

Our mid-stream segment competes with purchasers and gatherers of all types and sizes, including those affiliated with various producers, other major pipeline companies, and independent gatherers for the right to purchase natural gas and NGLs, build gathering and processing systems, and deliver the natural gas and NGLs once the gathering and processing systems are established. The principal elements of competition include the rates, terms, and availability of services, reputation, and the flexibility and reliability of service.

OIL AND NATURAL GAS PROGRAMS AND CONFLICTS OF INTEREST

Unit Petroleum Company serves as the general partner of 13 oil and gas limited partnerships (the employee partnerships) which were formed to allow certain of our qualified employees and our directors to participate in Unit Petroleum’s oil and gas exploration and production operations. Employee partnerships were formed for each year beginning with 1984 and ending with 2011. We also had three non-employee partnerships, one formed in 1984 and two formed in 1986 (investments by third parties). Effective December 31, 2014, the 1984 partnership was dissolved and effective December 31, 2016, the two 1986 partnerships were dissolved.

The employee partnerships formed in 1984 through 1999 have been combined into a single consolidated partnership. The employee partnerships each have a set annual percentage (ranging from 1% to 15%) of our interest that the partnership acquires in most of the oil and natural gas wells we drill or acquire for our account during the year in which the partnership was formed. The total interest the participants have in our oil and natural gas wells by participating in these partnerships does not exceed one percent of our interest in the wells.

Under our partnership agreements, the general partner has broad discretionary authority to manage the business and operations of the partnership, including the authority to decide regarding the partnership’s participation in a drilling location or a property acquisition, the partnership’s expenditure of funds, and distributing funds to partners. Because the business activities of the limited partners and the general partner are different, conflicts of interest will exist, and it is impossible to entirely eliminate these conflicts. Additionally, conflicts of interest may arise when we are the operator of an oil and natural gas well and also provide contract drilling services. In these cases, the drilling operations are conducted under drilling contracts containing terms comparable to those contained in our drilling contracts with non-affiliated operators. We believe we fulfill our responsibility to each contracting party and comply fully with the terms of the agreements which regulate these conflicts.

Effective January 1, 2019, we elected to terminate and wind down all of the remaining employee limited partnerships. In accordance with the partnership agreements, we, as the liquidating trustees will value the interests of the limited partners using the formula provided in each partnership agreement and purchase those interests. Presently, we expect the total purchase price

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for all of the limited partners interests will be approximately $0.6 million. We have no plans to sponsor additional employee limited partnerships.

These partnerships are further described in Notes 2 and 11 to the Consolidated Financial Statements in Item 8 of this report.

EMPLOYEES

As of February 12, 2019, we had approximately 913 employees in our contract drilling segment, 261 employees in our oil and natural gas segment, 125 employees in our mid-stream segment, and 77 in our general corporate area. None of our employees are members of a union or labor organization nor have our operations ever been interrupted by a strike or work stoppage. We consider relations with our employees to be satisfactory.

GOVERNMENTAL REGULATIONS

General. Our business depends on the demand for services from the oil and natural gas exploration and development industry, and therefore our business can be affected by political developments and changes in laws and regulations that control or curtail drilling for oil and natural gas for economic, environmental, or other policy reasons.

Various state and federal regulations affect the production and sale of oil and natural gas. All states in which we conduct activities impose varying restrictions on the drilling, production, transportation, and sale of oil and natural gas. This discussion of certain laws and regulations affecting our operations should not be relied on as an exhaustive review of all regulatory considerations affecting us, due to the multitude of complex federal, state, and local regulations, and their susceptibility to change at any time by later agency actions and court rulings that may affect our operations.

Natural Gas Sales and Transportation. Under the Natural Gas Act of 1938, the Federal Energy Regulatory Commission (FERC) regulates the interstate transportation and the sale in interstate commerce for resale of natural gas. FERC's jurisdiction over interstate natural gas sales has been substantially modified by the Natural Gas Policy Act under which FERC continued to regulate the maximum selling prices of certain categories of gas sold in "first sales" in interstate and intrastate commerce. Effective January 1, 1993, however, the Natural Gas Wellhead Decontrol Act (the Decontrol Act) deregulated natural gas prices for all "first sales" of natural gas. Because "first sales" include typical wellhead sales by producers, all natural gas produced from our natural gas properties is sold at market prices, subject to the terms of any private contracts which may be in effect. FERC's jurisdiction over interstate natural gas transportation is not affected by the Decontrol Act.

Our sales of natural gas are affected by intrastate and interstate gas transportation regulation. Beginning in 1985, FERC adopted regulatory changes that have significantly altered the transportation and marketing of natural gas. These changes are intended by FERC to foster competition by, among other things, transforming the role of interstate pipeline companies from wholesale marketers of natural gas to the primary role of gas transporters. All natural gas marketing by the pipelines must divest to a marketing affiliate, which operates separately from the transporter and in direct competition with all other merchants. Because of the various omnibus rulemaking proceedings in the late 1980s and the later individual pipeline restructuring proceedings of the early to mid-1990s, interstate pipelines must provide open and nondiscriminatory transportation and transportation-related services to all producers, natural gas marketing companies, local distribution companies, industrial end users, and other customers seeking service. Through similar orders affecting intrastate pipelines that provide similar interstate services, FERC expanded the impact of open access regulations to certain aspects of intrastate commerce.

FERC has pursued other policy initiatives that affected natural gas marketing. Most notable are (1) the large-scale divestiture of interstate pipeline-owned gas gathering facilities to affiliated or non-affiliated companies; (2) further development of rules governing the relationship of the pipelines with their marketing affiliates; (3) the publication of standards relating to using electronic bulletin boards and electronic data exchange by the pipelines to make available transportation information timely and to enable transactions to occur on a purely electronic basis; (4) further review of the role of the secondary market for released pipeline capacity and its relationship to open access service in the primary market; and (5) development of policy and promulgation of orders pertaining to its authorization of market-based rates (rather than traditional cost-of-service based rates) for transportation or transportation-related services on the pipeline’s demonstration of lack of market control in the relevant service market.

Because of these changes, independent sellers and buyers of natural gas have gained direct access to the particular pipeline services they need and can better conduct business with a larger number of counter parties. These changes generally have improved the access to markets for natural gas while substantially increasing competition in the natural gas marketplace.

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However, we cannot predict what new or different regulations FERC and other regulatory agencies may adopt or what effect later regulations may have on production and marketing of natural gas from our properties.

Although in the past Congress has been very active in the area of natural gas regulation as discussed above, the more recent trend has been for deregulation and the promotion of competition in the natural gas industry. In addition to "first sales" deregulation, Congress also repealed incremental pricing requirements and natural gas use restraints previously applicable. There continually are legislative proposals pending in the Federal and state legislatures which, if enacted, would significantly affect the petroleum industry. It is impossible to predict what proposals might be enacted by Congress or the various state legislatures and what effect these proposals might have on the production and marketing of natural gas by us. Similarly, and despite the trend toward federal deregulation of the natural gas industry, whether or to what extent that trend will continue or what the ultimate effect will be on the production and marketing of natural gas by us cannot be predicted.

Oil and Natural Gas Liquids Sales and Transportation. Our sales of oil and natural gas liquids currently are not regulated and are at market prices. The prices received from the sale of these products are affected by the cost of transporting these products to market. Much of that transportation is through interstate common carrier pipelines. Effective as of January 1, 1995, FERC implemented regulations generally grandfathering all previously approved interstate transportation rates and establishing an indexing system for those rates by which adjustments are made annually based on the rate of inflation, subject to certain conditions and limitations. These regulations may increase the cost of transporting oil and natural gas liquids by interstate pipeline, although the annual adjustments could cause decreased rates in a given year. These regulations have generally been approved on judicial review. Every five years, FERC examines the relationship between the annual change in the index and the actual cost changes experienced by the oil pipeline industry and makes any necessary adjustment in the index to be used during the ensuing five years. We cannot predict with certainty what effect the periodic review of the index by FERC will have on us.

Exploration and Production Activities. Federal, state, and local agencies also have promulgated extensive rules and regulations applicable to our oil and natural gas exploration, production, and related operations. The states we operate in require permits for drilling operations, drilling bonds, and filing reports about operations and impose other requirements relating to the exploration of oil and natural gas. Many states also have statutes or regulations addressing conservation matters including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from oil and natural gas wells, and regulating spacing, plugging and, abandonment of such wells. The statutes and regulations of some states limit the rate at which oil and natural gas is produced from our properties. The federal and state regulatory burden on the oil and natural gas industry increases our cost of doing business and affects our profitability. Because these rules and regulations are amended or reinterpreted frequently, we cannot predict the future cost or impact of complying with these laws.

Environmental.

General. Our operations are subject to federal, state, and local laws and regulations governing protection of the environment. These laws and regulations may require acquisition of permits before certain of our operations may be commenced and may restrict the types, quantities, and concentrations of various substances that can be released into the environment. Planning and implementation of protective measures must prevent accidental discharges. Spills of oil, natural gas liquids, drilling fluids, and other substances may subject us to penalties and cleanup requirements. Handling, storage, and disposal of both hazardous and non-hazardous wastes are subject to regulatory requirements.

The federal Clean Water Act, as amended by the Oil Pollution Act, the federal Clean Air Act, the federal Resource Conservation and Recovery Act, and their state counterparts, are the primary vehicles for imposition of such requirements and for civil, criminal, and administrative penalties and other sanctions for violation of their requirements. In addition, the federal Comprehensive Environmental Response Compensation and Liability Act and similar state statutes impose strict liability, without regard to fault or the legality of the original conduct, on certain classes of persons considered responsible for the release of hazardous substances into the environment. Such liability, which may be imposed for the conduct of others and for conditions others have caused, includes the cost of remedial action and damages to natural resources.

The EPA in 2015 established publicly owned treatment works (POTWs) effluent guidelines and standards for oil and gas extraction facilities which reflected industry best practices for unconventional oil and gas extraction facilities.

The EPA and the U.S. Army Corp of Engineers (Army) in 2015 proposed a new expansive definition of the "waters of the United States," which the United States Court of Appeals for the Sixth Circuit stayed nationally. On February 28, 2017, an Executive Order was issued and directed that the EPA and Army consider interpreting the term "navigable waters" in a manner

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consistent with Justice Scalia's opinion in Rapanos v. United States (2006). On March 6, 2017, the EPA and Army announced their intention to review and rescind or revise the 2015 Clean Water Rule and on June 27, 2017 they issued a proposed rule and written recommendations ("Obama rule"). On January 22, 2018, the United States Supreme Court in National Association of Manufacturers v. Department of Defense, et al. vacated the Sixth Circuit's nationwide stay. As a result, on January 31, 2018, the EPA and Army issued a rule providing that the 2015 definition of "waters of the United States" will not apply until two years following the date this rule is published in the Federal Register. In addition, Army includes wetlands within its definition of "waters of the United States." However, due to ongoing litigation, the Obama rule only applies to 28 states, and is enjoined with respect to the other 22 states challenging the Obama rule until such time as the litigation is resolved. On December 1, 2018, the EPA and Army released a proposed rule which would restrict the definition of "waters of the United States" to traditional large navigable waters, rivers and lakes and territorial seas used in interstate or foreign commerce as well as the tributaries, navigable lakes and ponds and tributaries that provide perennial or intermittent flow to them, as well as ditches that are "artificial channels" used to carry water and meet the conditions of a tributary or are adjacent to wetlands, impoundments of jurisdictional waters, and wetlands which are adjacent to jurisdictional waters in a "typical year" or which are connected by a channel to "waters of the United States." In 2016, the United States Supreme Court in U.S. Army Corps of Engineers v. Hawkes held that landowners can challenge in court an Army Corps of Engineers jurisdictional determination. It is anticipated this decision will provide landowners an important tool in negotiating and resolving conflicts with federal agencies over the extent of wetlands on a property. During 2018, the United States Courts of Appeals for the Fourth and Ninth Circuits applied the so-called "hydrological connection" theory to extend jurisdiction of the Clean Water Act to cover pollutants that reach surface waters via groundwater. The Sixth Circuit addressed the same issue, but rejected the Fourth and Ninth Circuits' decisions and held the opposite, consistent with 1994 Fifth Circuit and 2001 Seventh Circuit decisions. In response to an early December 2018 United States Supreme Court invitation to comment on the Fourth and Ninth Circuit's decisions, the United States Solicitor General asked the United States Supreme Court to resolve the Circuit Courts' split on whether the Clean Water Act applies when pollutants from a point source reach navigable waters after traveling through the groundwater. Petitions for review of the Fourth and Ninth Circuits' decision were filed with the United States Supreme Court in October and briefing completed in November 2018.

Endangered Species Act. The federal Endangered Species Act, called the "ESA," and analogous state laws regulate many activities, including oil and gas development, which could have an adverse effect on species listed as threatened or endangered under the ESA or their habitats. Designating previously unidentified endangered or threatened species could cause oil and natural gas exploration and production operators and service companies to incur additional costs or become subject to operating delays, restrictions or bans in affected areas, which impacts could adversely reduce drilling activities in affected areas. All three of our business segments could be subject to the effect of one or more species being listed as threatened or endangered within the areas of our operations. Numerous species have been listed or proposed for protected status in areas in which we provide or could undertake operations. The U.S. Fish and Wildlife Service ("FWS") and the National Marine Fisheries ("NMFS") in 2016 issued final revised definitions relating to impacts on critical habitats for potentially endangered species allowing exclusion of certain areas if they will not result in the extinction of the species. In 2017, the Western Governor's Association issued a Policy Resolution calling on Congress to amend and reauthorize the ESA based upon seven broad goals to make the act more workable and understandable. In December 2017, the Interior Department announced that it is working on possible changes to the ESA with the FWS to revise the regulations for listing endangered and threatened species and for designation of critical habitat. On July 19, 2018, the FWS and NMFS issued their proposals to revise the ESA regulations, to include: (1) reinstating the prior two-step approach to designating critical habitat, first considering designation of occupied habitat and then considering non-occupied habitat only if the existing inhabited area is inadequate to ensure conservation of the species; and (2) removal from the definition of "adverse modification" by deleting the second sentence in the definition which includes impact to land that "preclude or significantly delay development [physical or biological] features" essential to the conservation of the species. However, some of the new proposals may be impacted by the United States Supreme Court's decision issued in late November 2018. In vacating a United States Court of

Appeals for the Fifth Circuit decision involving an endangered species, in Weyerhaeuser Co. v. U.S. Fish & Wildlife Service, the Supreme Court held that (1) a proposed site must be “habitat” for an endangered species before the FWS can designate it as “habitat that is critical” and (2) federal courts should review for an abuse of discretion the FWS’s decision not to exclude a site from designation. In other words, only the actual habitat of an endangered species can be designated critical habitat, meaning that an uninhabited area that otherwise meets the definition of critical habitat should not be so designated. The presence of protected species in areas where we provide contract drilling or mid-stream services or conduct exploration and production operations could impair our ability to timely complete or carry out those services and, consequently, hurt our results of operations and financial position.

Climate Change. Recent scientific studies have suggested that emissions of certain gases, commonly called “greenhouse gases,” or GHGs, may be contributing to warming of the Earth’s atmosphere. As a result there have been many regulatory developments, proposals or requirements, and legislative initiatives introduced in the United States (and other parts of the World) that are focused on restricting the emission of carbon dioxide, methane, and other greenhouse gases.

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In 2007, the United States Supreme Court in Massachusetts, et al. v. EPA, held that carbon dioxide may be regulated as an “air pollutant” under the federal Clean Air Act if it represents a health hazard to the public. On December 7, 2009, the U.S. Environmental Protection Agency (EPA) responded to the Massachusetts, et al. v. EPA decision and issued a finding that the current and projected concentrations of GHGs in the atmosphere threaten the public health and welfare of current and future generations, and that certain GHGs from new motor vehicles and motor vehicle engines contribute to the atmospheric concentrations of GHG and hence to the threat of climate change. In addition, the EPA issued a final rule, effective in December 2009, requiring the reporting of GHG emissions from specified large (25,000 metric tons or more) GHG emission sources in the U.S., beginning in 2011 for emissions in 2010. During 2010, the EPA proposed revisions to these reporting requirements to apply to all oil and gas production, transmission, processing, and other facilities exceeding certain emission thresholds. On May 12, 2016, the EPA issued three final rules that together will curb emissions of methane, smog-forming volatile organic compounds (VOCs) and toxic air-pollutants such as benzene from new, reconstructed and modified oil and natural gas sources, while providing greater certainty about Clean Air Act permitting requirements for the industry ("Methane Rule"). First, the EPA issued updates to the New Source Performance Standards (NSPS) for the oil and natural gas industry to add requirements that the industry reduce emissions of GHGs and to cover additional equipment and activities in the oil and natural gas distribution chain by setting emissions limits for methane and to require owners/operators to find and repair methane and VOC leaks. Second, the EPA issued a source determination rule regarding the EPA’s air permitting rules as they apply to the oil and natural gas industry. The EPA clarified when multiple pieces of equipment and activities must be deemed a single source for determining whether (i) major source Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review requirements apply regarding preconstruction permitting and (ii) a Title V Operating permit is required. Third, the EPA issued a final rule to implement the Minor New Source Review Program in Indian Country for oil and natural gas production designed to limit emissions of harmful air pollution while making the preconstruction permitting process more streamlined and efficient. These regulations will cause additional costs to reduce emissions of GHGs associated with our operations and could hurt demand for the crude oil we gather, transport, store or otherwise handle in connection with our services. Although the EPA announced in April 2017 it will reconsider the GHG oil and gas emissions rule and delay its compliance, lawsuits have prevented such an effort. On September 1, 2018, the EPA proposed revisions to its Methane Rule, which the EPA estimates would “significantly reduce regulatory burden, saving the industry tens of millions of dollars in compliance each year.” The EPA proposes to revise (decrease) the monitoring frequencies for fugitive emissions (leaks) at non-low production well sites, low production well sites and compressor stations. The EPA also proposes to allow owners/operators up to 60 days after fugitive emissions are detected to complete repairs, provided that a first attempt at repair has to be made within the first 30 days.

Hydraulic Fracturing. Our oil and natural gas segment routinely applies hydraulic fracturing techniques to many of our oil and natural gas properties, including our unconventional resource plays in the Granite Wash of Texas and Oklahoma, the Marmaton of Oklahoma, the Wilcox of Texas, and the Mississippian of Kansas. On July 25, 2017, the Bureau of Land Management announced a proposal to rescind the 2015 Department of Interior final rule on hydraulic fracturing, a rule that was never in effect due to pending litigation. Multiple bills have been introduced in Congress that would (i) block federal regulation of hydraulic fracturing in favor of state rules, (ii) allow a state to regulate hydraulic fracturing on federal lands within that state, (iii) prevent federal regulation of hydraulic regulation to apply to any land held in trust or restricted status for the benefit of Indians without their express consent, (iv) repeal the exemption for hydraulic fracturing in the Safe Drinking Water Act, and/or (v) require the disclosure of chemicals used in hydraulic fracturing. In addition, certain states in which we operate, including Texas, Oklahoma, Kansas, Colorado, and Wyoming have adopted, and other states and municipalities and other local governmental entities in some states, have and others are considering adopting regulations and ordinances that could impose more stringent permitting, public disclosure of fracking fluids, waste disposal, and well construction requirements on these operations, and even restrict or ban hydraulic fracturing in certain circumstances.

On December 31, 2016, the EPA released its scientific Final Report on Impacts from Hydraulic Fracturing Activities on Drinking Water. The EPA states the report, which was done at the request of Congress, provides scientific evidence that hydraulic fracturing activities can affect drinking water resources in the United States under some circumstances. The EPA identifies six conditions under which impacts from hydraulic fracturing activities can be more frequent or severe and existing uncertainties and data gaps. Both the EPA and the United States Geological Survey (USGS) have made statements indicating that activities associated with hydraulic fracturing may be causing earthquakes, with the focus being on wastewater disposal wells rather than injection wells. In an August 2015 report sent to the Texas Railroad Commission, the EPA stated it believes there is a significant possibility that North Texas earthquake activity is associated with disposal wells. The USGS has stated that hydraulic fracturing causes small earthquakes, but they are almost always too small to be detected. Regarding disposal wells, the USGS has stated that the injection of wastewater and salt water by deep wells into the subsurface can cause earthquakes that are large enough to be felt and may cause damage. As a result, the USGS and its university partners have deployed seismometers at sites of known or possible injection induced earthquakes in Arkansas, Colorado, Kansas, Oklahoma, Ohio and Texas and that it is also developing methods to assess the earthquake hazard associated with wastewater injection wells.

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Any new laws, regulation, or permitting requirements regarding hydraulic fracturing could lead to operational delay, or increased operating costs or third party or governmental claims, and could result in additional burdens that could delay or limit the drilling services we provide to third parties whose drilling operations could be affected by these regulations or increase our costs of compliance and doing business and delay the development of unconventional gas resources from shale formations which are not commercial without using hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the oil and natural gas we can ultimately produce from our reserves.

Other; Compliance Costs. We cannot predict future legislation or regulations. It is possible that some future laws, regulations, and/or ordinances could increase our compliance costs and/or impose additional operating restrictions on us as well as those of our customers. Such future developments also might curtail the demand for fossil fuels which could hurt the demand for our services, which could hurt our future results of operations. Likewise we cannot predict with any certainty whether any changes to temperature, storm intensity or precipitation patterns because of climate change (or otherwise) will have a material impact on our operations.

Compliance with applicable environmental requirements has not, to date, had a material effect on the cost of our operations, earnings, or competitive position. However, as noted above in our discussion of the regulation of GHGs and hydraulic fracturing, compliance with amended, new or more stringent requirements of existing environmental regulations or requirements may cause us to incur additional costs or subject us to liabilities that may have a material adverse effect on our results of operations and financial condition.

Item 1A. Risk Factors

FORWARD-LOOKING STATEMENTS/CAUTIONARY STATEMENT AND RISK FACTORS

This report contains "forward-looking statements" – meaning, statements related to future events within the meaning of Section 27A of the Securities Act of 1933, as amended and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, included or incorporated by reference in this document which addresses activities, events or developments which we expect or anticipate will or may occur, are forward-looking statements. The words "believes," "intends," "expects," "anticipates," "projects," "estimates," "predicts," and expressions are used to identify forward-looking statements. This report modifies and supersedes documents filed by us before this report. In addition, certain information we file with the SEC in the future will automatically update and supersede information in this report.

These forward-looking statements include, among others, such things as:

•the amount and nature of our future capital expenditures and how we expect to fund our capital expenditures;
•prices for oil, NGLs, and natural gas;
•demand for oil, NGLs, and natural gas;
•our exploration and drilling prospects;
•the estimates of our proved oil, NGLs, and natural gas reserves;
•oil, NGLs, and natural gas reserve potential;
•development and infill drilling potential;
•expansion and other development trends of the oil and natural gas industry;
•our business strategy;
•our plans to maintain or increase production of oil, NGLs, and natural gas;
•the number of gathering systems and processing plants we plan to construct or acquire;
•volumes and prices for natural gas gathered and processed;
•expansion and growth of our business and operations;
•demand for our drilling rigs and drilling rig rates;

- our belief that the final outcome of our legal proceedings will not materially affect our financial results;
- our ability to timely secure third-party services used in completing our wells;

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•our ability to transport or convey our oil, NGLs, or natural gas production to established pipeline systems;
•impact of federal and state legislative and regulatory actions affecting our costs and increasing operating restrictions or delays and other adverse impacts on our business;
•our projected production guidelines for the year;
•our anticipated capital budgets;
•our financial condition and liquidity;
•the number of wells our oil and natural gas segment plans to drill during the year;
•our intended use of the proceeds from the sale of 50% of the interest we owned in our mid-stream segment; and
•our estimates of the amounts of any ceiling test write-downs or other potential asset impairments we may have to record in future periods.

These statements are based on certain assumptions and analyses made by us considering our experience and our perception of historical trends, current conditions, and expected future developments and other factors we believe are appropriate in the circumstances. Whether actual results and developments will conform to our expectations and predictions is subject to several risks and uncertainties any one or combination of which could cause our actual results to differ materially from our expectations and predictions, including:

•the risk factors discussed in this document and in the documents (if any) we incorporate by reference;
•general economic, market, or business conditions;
•the availability of and nature of (or lack of) business opportunities we pursue;
•demand for our land drilling services;
•changes in laws or regulations;
•changes in the current geopolitical situation;
•risks relating to financing, including restrictions in our debt agreements and availability and cost of credit;
•risks associated with future weather conditions;
•decreases or increases in commodity prices;
•putative class action lawsuits that may result in substantial expenditures and divert management's attention; and
•other factors, most of which are beyond our control.

You should not place undue reliance on these forward-looking statements. Except as required by law, we disclaim any intention to update forward-looking information and to release publicly the results of any future revisions we may make to forward-looking statements to reflect events or circumstances after the date of this document to reflect unanticipated events.

To help provide you with a more thorough understanding of the possible effects of these influences on any forward-looking statements made by us, this discussion outlines some (but not all) of the factors that could cause our consolidated results to differ materially from those that may be presented in any forward-looking statement made by us or on our behalf.

Demand for our contract drilling and mid-stream services depends substantially on the levels of expenditures by the oil and gas industry. A substantial or an extended decline in oil and gas prices could cause lower expenditures by the oil and gas industry, which could have a material adverse effect on our financial condition, results of operations and cash flows. Demand for our contract drilling and mid-stream services depends substantially on the level of expenditures by the oil and gas industry for the exploration, development and production of oil and natural gas reserves. These expenditures depend generally on the industry’s view of future oil and natural gas prices and are sensitive to the industry’s view of future economic growth and the resulting impact on demand for oil and natural gas. Declines, and anticipated declines, in oil and gas prices could also result in project modifications, delays or cancellations, general business disruptions, and delays in payment of, or nonpayment of, amounts owed to us. These effects could have a material adverse effect on our financial condition, results of operations and cash flows.

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The oil and gas industry has historically experienced periodic downturns, which have been characterized by diminished demand for oilfield services and downward pressure on the prices we charge. A significant downturn in the oil and gas industry could cause a reduction in demand for oilfield services and could hurt our financial condition, results of operations and cash flows.

Oil, NGLs, and Natural Gas Prices. Besides the impact oil and gas prices may have on our contract drilling and mid-stream segments, the prices we receive for our oil, NGLs, and natural gas production directly affect our revenues, profitability, and cash flow and our ability to meet our projected financial and operational goals. The prices for oil, NGLs, and natural gas are determined on several factors beyond our control, including:

•the demand for and supply of oil, NGLs, and natural gas;
•weather conditions in the continental United States (which can greatly influence the demand and prices for natural gas);
•the amount and timing of oil, liquid natural gas, and liquefied petroleum gas imports and exports;
•the ability of distribution systems in the United States to effectively meet the demand for oil, NGLs, and natural gas, particularly in times of peak demand which may result because of adverse weather conditions;
•the ability or willingness of the OPEC to set and maintain production levels for oil;
•oil and gas production levels by non-OPEC countries;
•the level of excess production capacity;
•political and economic uncertainty and geopolitical activity;
•governmental policies and subsidies;
•the costs of exploring for producing and delivering oil and gas; and
•technological advances affecting energy consumption.

Oil prices are extremely sensitive to influences domestic and foreign based on political, social or economic underpinnings, any of which could have an immediate and significant effect on the price and supply of oil. In addition, prices of oil, NGLs, and natural gas have been at various times influenced by trading on the commodities markets. That trading has increased the volatility associated with these prices resulting in large differences in prices even on a week-to-week and month-to-month basis. These factors, especially when coupled with much of our product prices being determined daily, can, and do, lead to wide fluctuations in the prices we receive.

Based on our 2018 production, a $0.10 per Mcf change in what we receive for our natural gas production, without the effect of derivatives, would cause a corresponding $439,000 per month ($5.3 million annualized) change in our pre-tax operating cash flow. A $1.00 per barrel change in our oil price, without the effect of derivatives, would have a $228,000 per month ($2.7 million annualized) change in our pre-tax operating cash flow and a $1.00 per barrel change in our NGLs price, without the effect of derivatives, would have a $393,000 per month ($4.7 million annualized) change in our pre-tax operating cash flow.

To reduce our exposure to short-term fluctuations in the price of oil, NGLs, and natural gas, we sometimes enter into derivative contracts such as swaps and collars. To date, we have derivatives covering part, but not all of our production which provides price protection only against declines in oil, NGLs, and natural gas prices on the production subject to our derivatives, but not otherwise. Should market prices for the production we have derivatives exceed the prices due under our derivative contracts, our derivative contracts then expose us to risk of financial loss and limit the benefit to us of those increases in market prices. During 2018, all of our NGLs volumes, a quarter of our oil, and about a half of our natural gas volumes were sold at market responsive prices. To help manage our cash flow and capital expenditure requirements, we had derivative contracts on approximately 75% and 49% of our 2018 average daily production for oil and natural gas, respectively. A more thorough discussion of our derivative arrangements is contained in the Management’s Discussion and Analysis of Financial Condition and Results of Operations section of this report in Item 7.

Uncertainty of Oil, NGLs, and Natural Gas Reserves; Ceiling Test. Many uncertainties are inherent in estimating quantities of oil, NGLs, and natural gas reserves and their values, including many factors beyond our control. The oil, NGLs, and natural gas reserve information in this report represents only an estimate of these reserves. Oil, NGLs, and natural gas reservoir engineering is a subjective and an inexact process of estimating underground accumulations of oil, NGLs, and natural

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gas that cannot be measured in an exact manner. Estimates of economically recoverable oil, NGLs, and natural gas reserves depend on several variable factors, including historical production from the area compared with production from other producing areas, and assumptions about:

•reservoir size;
•the effects of regulations by governmental agencies;
•future oil, NGLs, and natural gas prices;
•future operating costs;
•severance and excise taxes;
•operational risks;
•development costs; and
•workover and remedial costs.

Some or all of these assumptions may vary considerably from actual results. For these and other reasons, estimates of the economically recoverable quantities of oil, NGLs, and natural gas attributable to any group of properties, classifications of those oil, NGLs, and natural gas reserves based on risk of recovery, and estimates of the future net cash flows from oil, NGLs, and natural gas reserves prepared by different engineers or by the same engineers but at different times may vary substantially. Accordingly, oil, NGLs, and natural gas reserve estimates may be subject to periodic downward or upward adjustments. Actual production, revenues, and expenditures regarding our oil, NGLs, and natural gas reserves will likely vary from estimates and those variances may be material.

The information regarding discounted future net cash flows in this report is not necessarily the current market value of the estimated oil, NGLs, and natural gas reserves attributable to our properties. Using full cost accounting requires us to use the unweighted arithmetic average of the commodity prices existing on the first day of each of the 12 months before the end of the reporting period to calculate discounted future revenues, unless prices were otherwise determined under contractual arrangements. Actual future prices and costs may be materially higher or lower. Actual future net cash flows are also affected, in part, by these factors:

•the amount and timing of oil, NGLs, and natural gas production;
•supply and demand for oil, NGLs, and natural gas;
•increases or decreases in consumption; and
•changes in governmental regulations or taxation.

In addition, the 10% discount factor, required by the SEC for calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and the risks associated with our operations or the oil and natural gas industry.

We review quarterly the carrying value of our oil and natural gas properties under the full cost accounting rules of the SEC. Under these rules, capitalized costs of proved oil and natural gas properties may not exceed the present value of estimated future net revenues from those proved reserves, discounted at 10%. Application of this “ceiling test” generally requires pricing future revenue at the unescalated 12-month average price and requires a write-down for accounting purposes if we exceed the ceiling. We may be required to write-down the carrying value of our oil and natural gas properties when oil, NGLs, and natural gas prices are depressed. If a write-down is required, it would cause a charge to earnings but would not impact our cash flow from operating activities. Once incurred, a write-down is not reversible.

Debt and Bank Borrowing. We have incurred and expect to continue to incur substantial capital expenditures in our operations. Historically, we have funded our capital needs through a combination of internally generated cash flow and borrowings under our bank credit agreements. In 2011 and 2012, we issued $250.0 million (the 2011 Notes) and

$400.0 million (the 2012 Notes), respectively, of senior subordinated notes (collectively, the Notes). We have, and will continue to have, a certain amount of indebtedness. At December 31, 2018, we had no outstanding long-term debt under the Unit or Superior credit agreement, and $644.5 million, net of unamortized discount and debt issuance costs, under the Notes.

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Depending on our debt, the cash flow needed to satisfy that debt and the covenants in our bank credit agreements and those applicable to the Notes could:

•limit funds otherwise available for financing our capital expenditures, our drilling program or other activities or cause us to curtail these activities;
•limit our flexibility in planning for or reacting to changes in our business;
•place us at a competitive disadvantage to those of our competitors that are less indebted than we are;
•make us more vulnerable during periods of low oil, NGLs, and natural gas prices or if a downturn in our business occurs; and
•prevent us from obtaining additional financing on acceptable terms or limit amounts available under our existing or any future credit facilities.

Our ability to meet our debt obligations depends on our future performance. If the requirements of our indebtedness are not satisfied, a default could be deemed to occur and our lenders or the holders of the Notes could accelerate the payment of the outstanding indebtedness. If that were to happen, we would not have sufficient funds available (and probably could not obtain the financing required) to meet our obligations.

Our existing debt, and our future debt, if any, is, largely, based on the costs associated with the projects we undertake and of our cash flow. Generally, our normal operating costs are those resulting from the drilling of oil and natural gas wells, the acquisition of producing properties, the costs associated with the maintenance, upgrade, or expansion of our drilling rig fleet, and the operations of our natural gas buying, selling, gathering, processing, and treating systems. To some extent, these costs, particularly the first two, are discretionary and we maintain some control regarding the timing or the need to incur them. But, sometimes, unforeseen circumstances may arise, like an unanticipated opportunity to make a large acquisition or the need to replace a costly drilling rig component due to an unexpected loss, which could force us to incur additional debt above what we had expected or forecasted. Likewise, if our cash flow should prove insufficient to cover our cash requirements we would need to increase our debt either through bank borrowings or otherwise.

RISK FACTORS

Many other factors could hurt our business. This discussion describes the material risks currently known to us. However, additional risks we do not know about or that we currently view as immaterial may also impair our business or hurt the value of our securities. You should carefully consider the risks described below together with the other information contained in, or incorporated by reference into, this report.

If demand for oil, NGLs, and natural gas is reduced, our ability to market and produce our oil, NGLs, and natural gas may be negatively affected.

Historically, oil, NGLs, and natural gas prices have been volatile, with significant increases and significant price drops being experienced occasionally. Various factors beyond our control will have a significant effect on oil, NGLs, and natural gas prices. Those factors include, among other things, the domestic and foreign supply of oil, NGLs, and natural gas, the price of imports, the levels of consumer demand, the price and availability of alternative fuels, the availability of pipeline capacity, and changes in existing and proposed federal regulation and price controls.

The oil, NGLs, and natural gas markets are also unsettled due to several factors. Production from oil and natural gas wells in some geographic areas of the United States has been curtailed for considerable periods of time due to a lack of market demand and transportation and storage capacity. It is possible, however, that some of our wells may be shut-in or that oil, NGLs, and natural gas will be sold on terms less favorable than might otherwise be obtained should demand for oil, NGLs, and natural gas decrease. Competition for markets has been vigorous and there remains great uncertainty about prices that purchasers will pay. Oil, NGLs, and natural gas surpluses could cause our inability to market oil, NGLs, and natural gas profitably, causing us to curtail production and/or receive lower prices for our oil, NGLs, and natural gas, situations which would hurt us.

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Disruptions in the financial markets could affect our ability to obtain financing or refinance existing indebtedness on reasonable terms and may have other adverse effects.

Commercial-credit and equity market disruptions may cause tight capital markets in the United States. Liquidity in the global-capital markets can be severely contracted by market disruptions making terms for certain financings less attractive, and in certain cases, result in the unavailability of certain types of financing. Because credit and equity market turmoil, we may not be able to obtain debt or equity financing, or refinance existing indebtedness on favorable terms, which could affect operations and financial performance.

Oil, NGLs, and natural gas prices are volatile, and low prices have negatively affected our financial results and could do so in the future.

Our revenues, operating results, cash flow, and growth depend substantially on prevailing prices for oil, NGLs, and natural gas. Historically, oil, NGLs, and natural gas prices and markets have been volatile, and they are likely to continue to be volatile. Any decline in prices would have a negative impact on our future financial results and our ability to grow our business segments.

Prices for oil, NGLs, and natural gas are subject to wide fluctuations in response to relatively minor changes in the actual or perceived supply of and demand for oil, NGLs, and natural gas, market uncertainty, and many additional factors that are beyond our control. These factors include:

•political conditions in oil producing regions;
•the ability of the members of the OPEC to agree on prices and their ability or willingness to maintain production quotas;
•actions taken by foreign oil and natural gas companies;
•the price of foreign oil imports;
•imports and exports of oil and liquefied natural gas;
•actions of governmental authorities;
•the domestic and foreign supply of oil, NGLs, and natural gas;
•the level of consumer demand;
•United States storage levels of oil, NGLs, and natural gas;
•weather conditions;
•domestic and foreign government regulations;
•the price, availability, and acceptance of alternative fuels;
•volatility in ethane prices causing rejection of ethane as part of the liquids processed stream; and
•worldwide economic conditions.

These factors and the volatile nature of the energy markets make it impossible to predict with any certainty the future prices of oil, NGLs, and natural gas.

Our contract drilling operations depend on levels of activity in the oil, NGLs, and natural gas exploration and production industry.

Our contract drilling operations depend on the level of activity in oil, NGLs, and natural gas exploration and production in our operating markets. Both short-term and long-term trends in oil, NGLs, and natural gas prices affect the level of that activity. Because oil, NGLs, and natural gas prices are volatile, the level of exploration and production activity can also be volatile. Any decrease from current oil, NGLs, and natural gas prices could further depress the level of exploration and production activity. This, in turn, would likely result in further declines in the demand for our drilling services and would have an adverse effect on our contract drilling revenues, cash flows, and profitability. As a result, the future demand for our drilling services is uncertain.

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The industries in which we operate are highly competitive, and many of our competitors have resources greater than we do.

The drilling industry in which we operate is generally very competitive. Most drilling contracts are awarded based on competitive bids, which may cause intense price competition. Some of our competitors in the contract drilling industry have greater financial and human resources than we do. These resources may enable them to better withstand periods of low drilling rig utilization, to compete more effectively based on price and technology, to build new drilling rigs or acquire existing drilling rigs, and to provide drilling rigs more quickly than we do in periods of high drilling rig utilization.

The oil and natural gas industry is also highly competitive. We compete in the areas of property acquisitions and oil and natural gas exploration, development, production, and marketing with major oil companies, other independent oil and natural gas concerns, and individual producers and operators. In addition, we must compete with major and independent oil and natural gas concerns in recruiting and retaining qualified employees. Many of our competitors in the oil and natural gas industry have resources substantially greater than we do.

The mid-stream industry is also highly competitive. We compete in areas of gathering, processing, transporting, and treating natural gas with other mid-stream companies. We are continually competing with larger mid-stream companies for acquisitions and construction projects. Many of our competitors have greater financial resources, human resources, and geographic presence larger than we do.

Growth through acquisitions is not assured.

We have experienced growth in each segment, in part, through mergers and acquisitions. The contract land drilling industry, the exploration and development industry, and the gas gathering and processing industry, have experienced significant consolidation over the past several years, and there can be no assurance that acquisition opportunities will be available. Even if available, there is no assurance we would have the financial ability to pursue the opportunity. And we are likely to continue to face intense competition from other companies for acquisition opportunities.

There can be no assurance we will:

•be able to identify suitable acquisition opportunities;
•have sufficient capital resources to complete additional acquisitions;
•successfully integrate acquired operations and assets;
•effectively manage the growth and increased size;
•maintain the crews and market share to operate any future drilling rigs we may acquire; or
•improve our financial condition, results of operations, business or prospects in any material manner because of any completed acquisition.

We may incur substantial indebtedness to finance future acquisitions and also may issue debt instruments, equity securities, or convertible securities in connection with any acquisitions. Debt service requirements could represent a significant burden on our results of operations and financial condition and issuing additional equity would be dilutive to existing shareholders. Also, continued growth could strain our management, operations, employees, and other resources.

Successful acquisitions, particularly those of oil and natural gas companies or of oil and natural gas properties, require an assessment of several factors, many of which are beyond our control. These factors include recoverable reserves, exploration potential, future oil, NGLs, and natural gas prices, operating costs, and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain.

Our operations have significant capital requirements, and our indebtedness could have important consequences.

We have experienced and will continue to experience substantial capital needs for our operations. We have $644.5 million of indebtedness outstanding (net of unamortized discount and debt issuance costs) under the senior subordinated notes we have issued to-date and, in addition, may borrow up to $425.0 million under the Unit credit agreement and up to $200.0 million under the Superior credit agreement. As of February 12, 2019, we had $36.2 million outstanding borrowings under our Unit

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credit agreement and had no outstanding borrowings under our Superior credit agreement. Our level of indebtedness, the cash flow to satisfy our indebtedness, and the covenants governing our indebtedness could:

•limit funds available for financing capital expenditures, our drilling program or other activities or cause us to curtail these activities;
•limit our flexibility in planning for, or reacting to changes in, our business;
•place us at a competitive disadvantage to some of our competitors that are less leveraged than we are;
•make us more vulnerable during periods of low oil, NGLs, and natural gas prices or if downturn in our business occurs; and
•prevent us from obtaining additional financing on acceptable terms or limit amounts available under our existing or any future credit facilities.

Our ability to meet our debt service and other contractual and contingent obligations will depend on our future performance. In addition, lower oil, NGLs, and natural gas prices could cause future reductions in the amount available for borrowing under our credit agreements, reducing our liquidity, and even triggering mandatory loan repayments.

The instruments governing our indebtedness contain various covenants limiting the conduct of our business.

The indentures governing our senior subordinated notes and our credit agreements contain various restrictive covenants that limit the conduct of our business. These agreements place certain limits on our ability to, among other things:

•incur additional indebtedness, guarantee obligations or issue disqualified capital stock;
•pay dividends or distributions on our capital stock or redeem, repurchase or retire our capital stock;
•make investments or other restricted payments;
•invest in Unrestricted Subsidiaries over $200.0 million;
•grant liens on assets;
•enter into transactions with stockholders or affiliates;
•sell assets;
•issue or sell capital stock of certain subsidiaries; and
•merge or consolidate.

In addition, our credit agreements also requires us to maintain a minimum current ratio and a maximum senior indebtedness or leverage ratio.

If we violate the restrictions in the indentures governing our senior subordinated notes, our credit agreements or any other subsequent financing agreements, a default may allow the creditors, if the agreements so provide, to accelerate the related indebtedness and any other indebtedness to which a cross-acceleration or cross-default provision applies. If that occurs, we may not make the required payments or borrow sufficient funds to refinance that debt. Even if new financing were available at that time, it may not be on terms acceptable to us. In addition, lenders may be able to terminate any commitments they had made to make available further funds.

Our future performance depends on our ability to find or acquire additional oil, NGLs, and natural gas reserves that are economically recoverable.

Production from oil and natural gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Unless we replace the reserves we produce, our reserves will decline, resulting eventually in a decrease in oil, NGLs, and natural gas production and lower revenues and cash flow from operations. Historically, we have increased reserves after taking production into account through exploration and development. We have conducted these activities on our existing oil and natural gas properties and on newly acquired properties. We may not continue to replace reserves from these activities at acceptable costs. Lower prices of oil, NGLs, and natural gas may further limit the reserves that can economically be developed. Lower prices also decrease our cash flow and may cause us to decrease capital expenditures.

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We are continually identifying and evaluating opportunities to acquire oil and natural gas properties, including acquisitions significantly larger than those consummated by us. We cannot assure you we will successfully consummate any acquisition, that we can acquire producing oil and natural gas properties that contain economically recoverable reserves or that any acquisition will be profitably integrated into our operations.

The competition for producing oil and natural gas properties is intense. This competition could mean that to acquire properties we must pay higher prices and accept greater ownership risks than we have in the past.

Our exploration and production and mid-stream operations involve high business and financial risk which could hurt us.

Exploration and development involve numerous risks that may cause dry holes, the failure to produce oil, NGLs, and natural gas in commercial quantities and the inability to fully produce discovered reserves. The cost of drilling, completing, and operating wells is substantial and uncertain. Numerous factors beyond our control may cause the curtailment, delay, or cancellation of drilling operations, including:

•unexpected drilling conditions;
•pressure or irregularities in formations;
•capacity of pipeline systems;
•equipment failures or accidents;
•adverse weather conditions;
•compliance with governmental requirements; and
•shortages or delays in the availability of drilling rigs, pressure pumping services, or delivery crews and the delivery of equipment.

Exploratory drilling is a speculative activity. Although we may disclose our overall drilling success rate, those rates may decline. Although we may discuss drilling prospects we have identified or budgeted for, we may ultimately not lease or drill these prospects within the expected time frame, or at all. Lack of drilling success will have an adverse effect on our future results of operations and financial condition.

Our mid-stream operations involve numerous risks, both financial and operational. The cost of developing gathering systems and processing plants is substantial and our ability to recoup these costs is uncertain. Our operations may be curtailed, delayed, or canceled because of many things beyond our control, including:

•unexpected changes in the deliverability of natural gas reserves from the wells connected to the gathering systems;
•availability of competing pipelines in the area;
•capacity of pipeline systems;
•equipment failures or accidents;
•adverse weather conditions;
•compliance with governmental requirements;
•delays in developing other producing properties within the gathering system's area of operation; and
•demand for natural gas and its constituents.

Many of the wells from which we gather and process natural gas are operated by other parties. We have little control over the operations of those wells which can act to increase our risk. Operators of those wells may act in ways not in our best interests.

Competition for experienced technical personnel may negatively affect our operations or financial results.

The success of our three segments and the success of our other activities integral to our operations will depend, in part, on our ability to attract and retain experienced geologists, engineers, and other professionals. Competition for these professionals can be intense, particularly when the industry is experiencing favorable conditions.

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Our derivative arrangements might limit the benefit of increases in oil, NGLs, and natural gas prices.

To reduce our exposure to short-term fluctuations in the price of oil, NGLs, and natural gas, we sometimes enter into derivative contracts. These derivative contracts apply to only a portion of our production and provide only partial price protection against declines in oil, NGLs, and natural gas prices. These derivative contracts may expose us to risk of financial loss and limit the benefit to us of increases in prices.

Estimates of our reserves are uncertain and may prove inaccurate.

Numerous uncertainties are inherent in estimating quantities of proved reserves and their values, including many factors beyond our control. The reserve data represents only estimates. Reservoir engineering is a subjective and inexact process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. Estimates of economically recoverable oil, NGLs, and natural gas reserves depend on several variable factors, including historical production from the area compared with production from other producing areas, and assumptions about:

•reservoir size;
•the effects of regulations by governmental agencies;
•future oil, NGLs, and natural gas prices;
•future operating costs;
•severance and excise taxes;
•development costs; and
•workover and remedial costs.

Some or all of these assumptions may vary considerably from actual results. Estimates of the economically recoverable quantities of oil, NGLs, and natural gas attributable to any group of properties, classifications of those reserves based on risk of recovery, and estimates of the future net cash flows from reserves prepared by different engineers or by the same engineers but at different times may vary substantially. Accordingly, reserve estimates may be subject to downward or upward adjustment. Actual production, revenues and expenditures regarding our reserves will likely vary from estimates, and those variances may be material.

The information regarding discounted future net cash flows should not be considered as the current market value of the estimated oil, NGLs, and natural gas reserves attributable to our properties. As required by the SEC, the estimated discounted future net cash flows from proved reserves are based on prices on the first day of the month for each month within the 12-month period before the end of the reporting period and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by these factors:

•the amount and timing of actual production;
•supply and demand for oil, NGLs, and natural gas;
•increases or decreases in consumption; and
•changes in governmental regulations or taxation.

In addition, the 10% per year discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our operations or the oil and natural gas industry.

If oil, NGLs, and natural gas prices decrease or are unusually volatile, we may have to take write-downs of our oil and natural gas properties, the carrying value of our drilling rigs or our natural gas gathering and processing

systems.

We review quarterly the carrying value of our oil and natural gas properties under the full cost accounting rules of the SEC. Under these rules, capitalized costs of proved oil and natural gas properties may not exceed the present value of estimated future net revenues from proved reserves, discounted at 10% per year. Application of the ceiling test generally requires pricing future revenue at the unweighted arithmetic average of the price on the first day of month for each month within the 12-month period before the end of the reporting period, unless prices were defined by contractual arrangements, and requires a write-down for accounting purposes if the ceiling is exceeded. We may be required to write-down the carrying value of our oil and

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natural gas properties when oil, NGLs, and natural gas prices are depressed. If a write-down is required, it would cause a charge to earnings, but would not impact cash flow from operating activities. Once incurred, a write-down of oil and natural gas properties is not reversible later. Because our ceiling tests use a rolling 12-month look back average price it is possible that a write down during a reporting period will not remove the need for us to take additional write downs in one or more succeeding periods. This would be the case when months with higher commodity prices roll off the 12-month period and are replaced with more recent months having lower commodity prices.

Our drilling equipment, transportation equipment, gas gathering and processing systems, and other property and equipment are carried at cost. We are required to periodically test to see if these values, including associated goodwill and other intangible assets, have been impaired whenever events or changes in circumstances suggest the carrying amount may not be recoverable. If any of these assets are determined to be impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value. An estimate of fair value is based on the best information available, including prices for similar assets. Changes in these estimates could cause us to reduce the carrying value of property, equipment, and related intangible assets. Once these values have been reduced, they are not reversible.

Our operations present inherent risks of loss that, if not insured or indemnified against, could hurt our results of operations.

Our contract drilling operations are subject to many hazards inherent in the drilling industry, including blowouts, cratering, explosions, fires, loss of well control, loss of hole, damaged or lost drilling equipment, and damage or loss from inclement weather. Our exploration and production and mid-stream operations are subject to these and similar risks. These events could cause personal injury or death, damage to or destruction of equipment and facilities, suspension of operations, environmental damage, and damage to the property of others. Generally, drilling contracts provide for the division of responsibilities between a drilling company and its customer, and we seek to obtain indemnification from our drilling customers by contract for some of these risks. If we cannot transfer these risks to drilling customers by contract or indemnification agreements (or to the extent we assume obligations of indemnity or assume liability for certain risks under our drilling contracts), we seek protection from some of these risks through insurance. However, some risks are not covered by insurance and we cannot assure you that the insurance we have or the indemnification agreements we have will adequately protect us against liability from the consequences of the hazards described above. An event not fully insured or indemnified against, or the failure of a customer to meet its indemnification obligations, could cause substantial losses. In addition, we cannot assure you that insurance will be available to cover any or all of these risks. Even if available, the insurance might not be adequate to cover all of our losses, or we might decide against obtaining that insurance because of high premiums or other costs.

We do not operate many of the wells in which we own an interest. Our operating risks for those wells and our ability to influence the operations for those wells are less subject to our control. Operators of those wells may act in ways not in our best interests.

Governmental and environmental regulations could hurt our business.

Our business is subject to federal, state, and local laws and regulations on taxation, the exploration for and development, production, and marketing of oil and natural gas, and safety matters. Many laws and regulations require drilling permits and govern the spacing of wells, rates of production, prevention of waste, unitization and pooling of properties, and other matters. These laws and regulations have increased the costs of planning, designing, drilling, installing, operating, and abandoning our oil and natural gas wells and other facilities. In addition, these laws and regulations, and any others that are passed by the jurisdictions where we have production, could limit the number of wells drilled or the allowable production from successful wells, which could limit our revenues.

We are (or could become) subject to complex environmental laws and regulations adopted by the jurisdictions where we own properties or operate. We could incur liability to governments or third parties for discharges of oil, natural gas or other pollutants into the air, soil or water, including responsibility for remedial costs. We could discharge these materials into the environment in many ways including:

- from a well or drilling equipment at a drill site;
- from gathering systems, pipelines, transportation facilities, and storage tanks;
- damage to oil and natural gas wells resulting from accidents during normal operations;
- sabotage; and
- blowouts, cratering, and explosions.

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Because the requirements imposed by laws and regulations frequently change, we cannot assure you that future laws and regulations, including changes to existing laws and regulations, will not hurt our business. The United States Congress and White House administration may impose or change laws and regulations that will hurt our business. Stricter standards, greater regulation, and more extensive permit requirements, could increase our future risks and costs related to environmental matters. In addition, because we acquire interests in properties operated in the past by others, we may be liable for environmental damage caused by the former operators, which liability could be material.

Any future implementation of price controls on oil, NGLs, and natural gas would affect our operations.

Certain groups have asserted efforts to have the United States Congress impose price controls on either oil, natural gas, or both. There is no way at this time to know what result these efforts will have nor, if implemented, their effect on our operations. However, it is possible that these efforts, if successful, would limit the amount we might get for our future oil, NGLs, and natural gas production. Any future limits on the price of oil, NGLs, and natural gas could also cause hurting the demand for our drilling services.

Provisions of Delaware law and our by-laws and charter could discourage change in control transactions and prevent shareholders from receiving a premium on their investment.

Our by-laws and charter provide for a classified board of directors with staggered terms and authorizes the board of directors to set the terms of preferred stock. In addition, our charter and Delaware law contain provisions that impose restrictions on business combinations with interested parties. Because of our by-laws, charter, and Delaware law, persons considering unsolicited tender offers or other unilateral takeover proposals may be more likely to negotiate with our board of directors rather than pursue non-negotiated takeover attempts. These provisions may make it more difficult for our shareholders to benefit from transactions opposed by an incumbent board of directors.

New technologies may cause our exploration and drilling methods to become obsolete, resulting in an adverse effect on our production.

Our industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, competitors may have greater financial, technical, and personnel resources that allow them to enjoy technological advantages and may allow them to implement new technologies before we can. We cannot be certain that we can implement technologies timely or at a cost acceptable to us. One or more technologies that we use or that we may implement may become obsolete or may not work as we expected and we may be hurt.

We may be affected by climate change and market or regulatory responses to climate change.

Climate change, including the impact of potential global warming regulations, could have a material adverse effect on our results of operations, financial condition, and liquidity. Restrictions, caps, taxes, or other controls on emissions of greenhouse gases, including diesel exhaust, could significantly increase our operating costs. Restrictions on emissions could also affect our customers that (a) use commodities we carry to produce energy, (b) use significant energy in producing or delivering the commodities we carry, or (c) manufacture or produce goods that consume significant energy or burn fossil fuels, including chemical producers, farmers and food producers, and automakers and other manufacturers. Significant cost increases, government regulation, or changes of consumer preferences for goods or services relating to alternative sources of energy or emissions reductions could materially affect the markets for the commodities associated with our business, which could have a material adverse effect on our results of operations, financial condition, and liquidity. Government incentives encouraging the use of alternative sources of energy could also affect certain of our customers and the markets for certain of the commodities associated with our business in an unpredictable manner that could alter our business activities. Finally, we could face increased costs related to defending and resolving legal claims and other litigation related to climate change and the alleged impact of our operations on climate change. These factors, individually or in operation with one or more of the other factors, or other unforeseen impacts of climate change could reduce the business activity we conduct and have a material adverse effect on our results of operations, financial condition, and liquidity.

The results of our operations depend on our ability to transport oil, NGLs, and gas production to key markets.

The marketability of our oil, NGLs, and natural gas production depends in part on the availability, proximity, and capacity of pipeline systems, refineries, and other transportation sources. The unavailability of or lack of capacity on these systems and

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facilities could cause the shut-in of producing wells or the delay or discontinuance of development plans for properties. Federal and state regulation of oil, NGLs, and natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines, and general economic conditions could hurt our ability to produce, gather and, transport oil, NGLs, and natural gas.

Losing one or several of our larger customers could have a material adverse effect on our financial condition and results of operations.

During 2018, sales to CVR Refining, LP and Valero Energy Corporation accounted for 14% and 10% of our oil and natural gas revenues, respectively. QEP Resources, Inc. and Slawson Exploration Company, Inc. were our largest third-party drilling customers accounting for approximately 16% and 10% of our total contract drilling revenues, respectively. And for our mid-stream segment, ONEOK, Inc. accounted for approximately 45% of our revenues. No other third party customer accounted for 10% or more of any of our individual segment revenues. Any of our customers may choose not to use our services and losing several our larger customers could have a material adverse effect on our financial condition and results of operations if we could not find replacements.

Shortage of completion equipment and services could delay or otherwise hurt our oil and natural gas segment's operations.

As there is an increase in horizontal drilling activity in certain areas, shortages could cause the availability of third party equipment and services required for completing wells drilled by our oil and natural gas segment. We could experience delays in completing some of our wells. Although we can try to reduce the delays associated with these services, we anticipate these services will be in high demand for the immediate future and could delay, restrict, or curtail part of our exploration and development operations, which could in turn harm our results.

Our mid-stream segment depends on certain natural gas producers and pipeline operators for a significant portion of its supply of natural gas and NGLs. Losing any of these producers could cause a decline in our volumes and revenues.

We rely on certain natural gas producers for a significant portion of our natural gas and NGLs supply. While some of these producers are subject to long-term contracts, we may not negotiate extensions or replacements of these contracts on favorable terms, if at all. Losing all or even a portion of the natural gas volumes supplied by these producers, because of competition or otherwise, could have a material adverse effect on our mid-stream segment unless we acquired comparable volumes from other sources.

The counterparties to our commodity derivative contracts may not perform their obligations to us, which could materially affect our cash flows and results of operations.

To reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we currently, and may in the future, enter into commodity derivative contracts for a significant portion of our forecasted oil, NGLs, and natural gas production. The extent of our commodity price exposure is related largely to the effectiveness and scope of our derivative activities, and to the ability of counterparties under our commodity derivative contracts to satisfy their obligations to us. If one or more of our counterparties are unable or unwilling to pay us under our commodity derivative contracts, it could have a material adverse effect on our financial condition and results of operations.

Reliance on management.

We depend greatly on the efforts of our executive officers and other key employees to manage our operations. The loss or unavailability of any of our executive officers or other key employees could have a material adverse effect on our business.

We are subject to various claims and litigation that could ultimately be resolved against us requiring material future cash payments and/or future material charges against our operating income and materially impairing our financial position.

The nature of our business makes us highly susceptible to claims and litigation. We are subject to various existing legal claims and lawsuits, which could have a material adverse effect on our consolidated financial position, results of operations, or cash flows. Any claims or litigation, even if fully indemnified or insured, could negatively affect our reputation among our customers and the public, and make it more difficult for us to compete effectively or obtain adequate insurance in the future.

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Derivative regulations in current financial reform legislation could impede our ability to manage business and financial risks by restricting our use of derivative instruments as hedges against fluctuating commodity prices and interest rates.

In July 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act was passed by Congress and signed into law. This Act contains significant derivative regulations, requiring that certain transactions be cleared on exchanges and a requirement to post cash collateral (commonly called margin) for such transactions. This Act provides for a potential exception from these clearing and cash collateral requirements for commercial end-users and it includes several defined terms used in determining how this exception applies to particular derivative transactions and the parties to those transactions.

We use crude oil and natural gas derivative instruments regarding a portion of our expected production to reduce commodity price uncertainty and enhance the predictability of cash flows relating the marketing of our crude oil and natural gas. As commodity prices increase, our derivative liability positions increase; however, none of our current derivative contracts require posting margin or similar cash collateral when there are changes in the underlying commodity prices referred to in these contracts.

Depending on the rules and definitions adopted by the Commodity Futures Trading Commission, we could have to post collateral with our dealer counterparties for our commodities derivative transactions. Such a requirement could have a significant impact on our business by reducing our ability to execute derivative transactions to reduce commodity price uncertainty and to protect cash flows. Requirements to post collateral would cause significant liquidity issues by reducing our ability to use cash for investment or other corporate purposes, or would require us to increase our level of debt. In addition, a requirement for our counterparties to post collateral would likely cause additional costs being passed on to us, thereby decreasing the effectiveness of our derivative contracts and our profitability.

Proposed federal and state legislative and regulatory initiatives relating to hydraulic fracturing could cause increased costs and additional operating restrictions or delays.

Hydraulic-fracturing is an essential and common practice in the oil and gas industry used to stimulate production of oil, natural gas, and associated liquids from dense subsurface rock formations. Our oil and natural gas segment routinely applies hydraulic-fracturing techniques to many of our oil and natural gas properties, including our unconventional resource plays in the Granite Wash of Texas and Oklahoma, the Marmaton and Hoxbar of Oklahoma, the Wilcox of Texas, and the Mississippian of Kansas. Hydraulic-fracturing involves using water, sand, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow the flow of hydrocarbons into the wellbore. The process is typically regulated by state oil and natural gas commissions; however, the Environmental Protection Agency (the EPA) has asserted federal regulatory authority over certain hydraulic-fracturing activities involving diesel under the Safe Drinking Water Act and published permitting guidance addressing the performance of such activities using diesel. The EPA is also seeking to require companies to disclose information regarding the chemicals used in hydraulic fracturing and the Bureau of Land Management has imposed requirements for hydraulic fracturing activities of federal lands. In addition, Congress has occasionally considered legislation to provide for federal regulation of hydraulic-fracturing and to require disclosure of the chemicals used in the hydraulic-fracturing process.

Certain states in which we operate, including Texas, Oklahoma, Kansas, Colorado, and Wyoming, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure of fracking fluids, waste disposal, and well construction requirements on hydraulic-fracturing operations or otherwise seek to ban fracturing activities altogether. For example, Texas adopted a law in June 2011 requiring disclosure to the Railroad Commission of Texas and the public of certain information regarding the components used in the hydraulic-fracturing process. Besides state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling and/or hydraulic fracturing. If state, local, or municipal legal restrictions are adopted in areas where we are conducting, or plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant, experience delays or curtailment pursuing exploration, development, or production activities, and perhaps even be precluded from the drilling and/or completion of wells.

There are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic-fracturing practices. The White House Council on Environmental Quality is coordinating a review of hydraulic-fracturing practices, and a committee of the United States House of Representatives investigated hydraulic-fracturing practices. Furthermore, several federal agencies are analyzing, or have been requested to review, many environmental issues associated with hydraulic fracturing. The EPA is evaluating the potential environmental effects of hydraulic fracturing on drinking water and groundwater. In addition, the U.S. Department of Energy has investigated practices the agency could recommend to better protect the environment from drilling using hydraulic-fracturing completion methods.

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And certain members of Congress have called on the U.S. Government Accountability Office to investigate how hydraulic fracturing might hurt water resources, the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing, and the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, and uncertainties associated with those estimates. These ongoing or proposed studies, depending on their course and results obtained, could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act or other regulatory processes.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil, natural gas, and associated liquids including from developing shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of additional federal, state or local laws or implementing regulations regarding hydraulic fracturing could cause a decrease in completing of new oil and gas wells, increased compliance costs and time, which could hurt our financial position, results of operations, and cash flows.

Our ability to produce crude oil, natural gas, and associated liquids economically and in commercial quantities could be impaired if we cannot acquire adequate supplies of water for our drilling operations and/or completions or cannot dispose of or recycle the water we use at a reasonable cost and under applicable environmental rules.

To our knowledge, there have been no citations, suits, or contamination of potable drinking water arising from our fracturing operations. We do not have insurance policies in effect intended to provide coverage for losses solely related to hydraulic fracturing operations; however, our general liability and excess liability insurance policies might cover third-party claims related to hydraulic fracturing operations and associated legal expenses depending on the specific nature of the claims, the timing of the claims, and the specific terms of such policies.

Uncertainty regarding increased seismic activity in Oklahoma and Kansas.

We conduct oil and natural gas exploration, development and drilling activities in Oklahoma, Kansas, and elsewhere. In recent years, Oklahoma and Kansas have experienced a significant increase in earthquakes and other seismic activity. Some parties believe there is a correlation between certain oil and gas activities and the increased occurrence of earthquakes. The extent of this correlation is the subject of studies by both state and federal agencies the results of which remain uncertain. We cannot state at this time what if any impact this seismic activity may have on us or our industry.

The hydraulic fracturing process on which we depend to produce commercial quantities of crude oil, natural gas, and associated NGLs from many reservoirs requires the use and disposal of significant quantities of water.

Our inability to secure sufficient amounts of water, or to dispose of or recycle the water used in our oil and natural gas segment operations, could adversely affect our operations. The imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of wastes, including, but not limited to, produced water, drilling fluids, and other wastes associated with the exploration, development or production of oil and natural gas.

Compliance with environmental regulations and permit requirements governing the withdrawal, storage and, use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions, or termination of our operations, the extent of which cannot be predicted, all of which could have an adverse effect on our operations and financial condition.

We may decide not to drill some prospects we have identified, and locations we drill may not yield oil, NGLs, and natural gas in commercially viable quantities.

Our oil and natural gas segment's prospective drilling locations are in various stages of evaluation, ranging from a prospect ready to drill to a prospect that will require additional geological and engineering analysis. Based on many factors, including future oil, NGLs, natural gas prices, the generation of additional seismic or geological information, and other factors, we may decide not to drill one or more of these prospects. As a result, we may not increase or maintain our reserves or production, which in turn could have an adverse effect on our business, financial position, and results of operations. In addition, the SEC's reserve reporting rules require that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of booking. At December 31, 2018, we had 158 proved

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undeveloped drilling locations. If we do not drill these locations within five years of initial booking, they may not continue to qualify for classification as proved reserves, and we may have to reclassify such reserves as unproved reserves. The reclassification of those reserves could also have a negative effect on the borrowing base under our credit facility.

The cost of drilling, completing, and operating a well is often uncertain, and cost factors can hurt the economics of a well. Our efforts will be uneconomic if we drill dry holes or wells that are productive but do not produce enough oil, NGLs, and natural gas to be commercially viable after drilling, operating, and other costs.

The borrowing base under the Unit credit agreement is determined semi-annually at the discretion of the lenders and is based in a large part on the prices for oil, NGLs, and natural gas.

Significant declines in oil, NGLs, and natural gas prices may cause a decrease in our borrowing base. The lenders can unilaterally adjust the borrowing base and therefore the borrowings permitted to be outstanding under the Unit credit agreement. If outstanding borrowings are over the borrowing base, we must (a) repay the amount in excess of the borrowing base, (b) dedicate additional properties to the borrowing base, or (c) begin monthly principal payments under the Unit credit agreement.

The amount Superior can borrow under its credit agreement may be impacted by its cash flow.

Superior must maintain a funded debt to consolidated EBITDA ratio of not greater than 4.00 to 1.00. As a result, if Superior's EBITDA falls below $50.0 million, its maximum funded debt would be limited to 4.00 times consolidated EBITDA.

We have $650.0 million outstanding under our 6.625% Senior Subordinated Notes that mature on May 15, 2021.

Our ability to make scheduled payments of the principal and interest on or to refinance our outstanding 6.625% Senior Subordinated Notes, depends on our financial and operating performance, which is subject to economic, financial, competitive and other factors, many of which are beyond our control. In addition, our ability to refinance this indebtedness will depend on the capital and credit markets and our financial condition prevailing at such time. We cannot provide assurance that our operating performance will generate sufficient cash flow or that our capital resources will be sufficient for payment of our obligations under this indebtedness or that we will be able to refinance this indebtedness on desirable terms, if at all, which could result in increased costs to us or require us to sell material assets or operations or use our available cash to meet our obligations under this indebtedness.

Potential listing of species as "endangered" under the federal Endangered Species Act could cause increased costs and new operating restrictions or delays on our operations and that of our customers, which could hurt our operations and financial results.

The federal Endangered Species Act (the ESA) and analogous state laws regulate a variety of activities, including oil and gas development, which could have an adverse effect on species listed as threatened or endangered under the ESA or their habitats. The designation of previously unidentified endangered or threatened species could cause oil and natural gas exploration and production operators and service companies to incur additional costs or become subject to operating delays, restrictions or bans in affected areas, which impacts could adversely reduce the amount of drilling activities in affected areas. All three of our business segments could be subject to the effect of one or more species being listed as threatened or endangered within the areas of our operations. Numerous species have been listed or proposed for protected status in areas in which we provide or could in the future undertake operations. In 2016, the U.S. Fish and Wildlife Service and the National Marine Fisheries issued final revised definitions relating to impacts on critical habitats for potentially endangered species allowing exclusion of certain areas so long as they will not result in the extinction of the species. In 2017, the Western Governor's Association issued a Policy Resolution calling on Congress to amend and reauthorize the ESA based upon seven broad goals to make the act more workable and understandable. In December 2017, the U.S. Department of Interior (the Interior Department) announced that it is working on possible changes to the ESA with the U.S. Fish and Wildlife Service to revise the regulations for listing endangered and threatened species and for designation of critical habitat. The presence of protected species in areas where we provide contract drilling or mid-stream services or conduct exploration and production operations could impair our ability to timely complete or carry out those services and, consequently, adversely affect our results of operations and financial position.

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Constructing our new proprietary BOSS drilling rigs is subject to risks, including delays and cost overruns, and may not meet our expectations.

We have designed and built several new proprietary 1,500 horsepower AC electric drilling rigs, which we call BOSS drilling rigs. This new design should position us to better meet the demands of our customers. Constructing any future new BOSS drilling rigs is subject to the risks of delays or cost overruns inherent in any large construction project because of numerous possible factors, including:

- shortages of equipment, materials or skilled labor;
- work stoppages and labor disputes;
- unscheduled delays in the delivery of ordered materials and equipment;
- unanticipated increases in the cost of equipment, labor and raw materials used in construction of our drilling rigs, particularly steel;
- weather interferences;
- difficulties in obtaining necessary permits or in meeting permit conditions;
- unforeseen design and engineering problems;
- failure or delay in obtaining acceptance of the drilling rig from our customer;
- failure or delay of third party equipment vendors or service providers; and
- lack of demand from the downturn in the oil and gas industry.

On our new BOSS drilling rigs, there can be no assurance we will:

- obtain additional new-build contract opportunities; or
- improve our financial condition, results of operations or prospects because of the new drilling rigs.

While we hold certain patents regarding our BOSS drilling rig design, it is still possible that third parties may claim we infringe their intellectual property rights. We may receive notices from others claiming that our BOSS drilling rig design infringes on their intellectual property rights. In that event we may resolve these claims by signing royalty and licensing agreements, redesigning the drilling rig, or paying damages. These outcomes may cause operating margins to decline. Besides money damages, in some jurisdictions plaintiffs can seek injunctive relief that may limit or prevent marketing and use of our drilling rigs that have infringing technologies.

Terrorist attacks or cyber-attacks could have a material adverse effect on our business, financial condition or results of operations.

Terrorist attacks or cyber-attacks may significantly affect the energy industry, and economic conditions, including our operations and our customers, as well as general economic conditions, consumer confidence and spending and market liquidity. Strategic targets, such as energy-related assets, may be at greater risk of future attacks than other targets in the United States. A cyber incident could result in information theft, data corruption, operational disruption and/or financial loss. Our insurance may not protect us against such occurrences. Consequently, it is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business, financial condition and results of operations.

The oil and natural gas industry has become increasingly dependent upon digital technologies, including information systems, infrastructure and cloud applications and services, to operate our businesses, process and record financial and operating data, communicate with our employees and business partners, analyze seismic and drilling information, estimate quantities of natural gas reserves, and perform other activities related to our businesses. Our business partners, including vendors, service providers, and financial institutions, are also dependent on digital technology.

As dependence on digital technologies has increased, cyber incidents, including deliberate attacks or unintentional events, have also increased. A cyber-attack could include gaining unauthorized access to digital systems for purposes of misappropriating assets or sensitive information, corrupting data, or causing operational disruption, or result in denial-of-service on websites.

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Our technologies, systems, networks, and those of our business partners may become the target of cyber-attacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period.

Deliberate attacks on our assets, or security breaches in our systems or infrastructure, the systems or infrastructure of third-parties or the cloud could lead to corruption or loss of our proprietary data and potentially sensitive data, delays in production or delivery, difficulty in completing and settling transactions, challenges in maintaining our books and records, environmental damage, communication interruptions, other operational disruptions and third-party liability, including the following:

•a cyber-attack on a vendor or service provider could result in supply chain disruptions which could delay or halt development of additional infrastructure, effectively delaying the start of cash flows from the project;
•a cyber-attack on our facilities may result in equipment damage or failure;
•a cyber-attack on mid-stream or downstream pipelines could prevent our product from being delivered, resulting in a loss of revenues;
•a cyber-attack on a communications network or power grid could cause operational disruption resulting in loss of revenues;
•deliberate corruption of our financial or operational data could result in events of non-compliance which could lead to regulatory fines or penalties; and
•business interruptions could result in expensive remediation efforts, distraction of management, damage to our reputation, or a negative impact on the price of our units.

Implementation of various controls and processes to monitor and mitigate security threats and to increase security for our information, facilities and infrastructure is costly and labor intensive. Moreover, there can be no assurance that such measures will be sufficient to prevent security breaches from occurring. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities. We are not aware that any attempts to breach our systems have successfully occurred.

We are the subject of putative class action lawsuits that may result in substantial expenditures and divert management's attention.

We are the subject of putative class action lawsuits in Oklahoma raising allegations that we underpaid royalties and that we failed to pay interest on untimely royalty payments. These lawsuits seek various remedies, including damages, injunctive relief, and attorney’s fees. For additional information on these lawsuits, see Item 3 Legal Proceedings in this Annual Report on Form 10-K.

Although we believe that the allegations in these lawsuits are without merit and intend to defend such litigation vigorously, litigation is subject to inherent uncertainties, and an adverse result in one of these lawsuits or other matters that may arise from time to time could have a material adverse effect on our business, results of operations and financial condition. Defending the lawsuits may be costly and, further, could require significant involvement of our senior management and may divert management's attention from our business and operations.

Ineffective internal controls could impact the accuracy and timely reporting of our business and financial results.

Our internal control over financial reporting (ICFR) may not prevent or detect misstatements because of its inherent limitations, including the possibility of human error, the circumvention or overriding of controls, or fraud. Even effective internal controls can provide only reasonable assurance with respect to the preparation and fair presentation of financial statements. If we fail to maintain the adequacy of our internal controls, including any failure to implement required new or improved controls, or if we experience difficulties in their implementation, our business and financial results could be harmed and we could fail to meet our financial reporting obligations. For example, in connection with the revisions made in this Form 10-K/A, management re-evaluated the effectiveness of our ICFR as of December 31, 2017 and concluded that a deficiency in our internal controls related to the control over the preparation and review of the financial statements, and therefore, that we did not maintain effective ICFR as of December 31, 2017. For a description of the material weakness identified by management and the remediation efforts being implemented for the material weakness, see Part II, Item 9A. Controls and Procedures. If the

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enhanced controls implemented to address the material weakness and to strengthen the overall internal control related to the preparation and review of the financial statements are not designed or do not operate effectively, if we are unsuccessful in implementing or following these enhanced processes, or we are otherwise unable to remediate the material weakness, this may result in untimely or inaccurate reporting of our financial results.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

The information called for by this item was consolidated with and disclosed in connection with Item 1 above.

Item 3. Legal Proceedings

Panola Independent School District No. 4, et al. v. Unit Petroleum Company, No. CJ-07-215, District Court of Latimer County, Oklahoma.

Panola Independent School District No. 4, Michael Kilpatrick, Gwen Grego, Carla Lessel, Thelma Christine Pate, Juanita Golightly, Melody Culberson, and Charlotte Abernathy are the Plaintiffs and are royalty owners in oil and gas drilling and spacing units for which the company's exploration segment distributes royalty. The Plaintiffs' central allegation is that the company's exploration segment has underpaid royalty obligations by deducting post-production costs or marketing related fees. Plaintiffs sought to pursue the case as a class action on behalf of persons who receive royalty from us for our Oklahoma production. We have asserted several defenses including that the deductions are permitted under Oklahoma law. We have also asserted that the case should not be tried as a class action due to the materially different circumstances that determine what, if any, deductions are taken for each lease. On December 16, 2009, the trial court entered its order certifying the class. On May 11, 2012 the court of civil appeals reversed the trial court's order certifying the class. The Plaintiffs petitioned the Supreme Court for certiorari and on October 8, 2012, the Plaintiff's petition was denied. On January 22, 2013, the Plaintiffs filed a second request to certify a class of royalty owners slightly smaller than their first attempt. Since then, the Plaintiffs have further amended their proposed class to just include royalty owners entitled to royalties under certain leases in Latimer, Le Flore, and Pittsburg Counties, Oklahoma. In July 2014, a second class certification hearing was held where, besides the defenses described above, we argued that the amended class definition is still deficient under the court of civil appeals opinion reversing the initial class certification. Closing arguments were held on December 2, 2014. There is no timetable for when the court will issue its ruling. The merits of Plaintiffs' claims will remain stayed while class certification issues are pending.

Cockerell Oil Properties, Ltd., v. Unit Petroleum Company, No. 16-cv-135-JHP, United States District Court for the Eastern District of Oklahoma.

On March 11, 2016, a putative class action lawsuit was filed against Unit Petroleum Company styled *Cockerell Oil Properties, Ltd., v. Unit Petroleum Company* in LeFlore County, Oklahoma. We removed the case to federal court in the Eastern District of Oklahoma. The plaintiff alleges that Unit Petroleum wrongfully failed to pay interest with respect to untimely royalty payments under Oklahoma's Production Revenue Standards Act. The lawsuit seeks actual and punitive damages, an accounting, disgorgement, injunctive relief, and attorney's fees. Plaintiff is seeking relief on behalf of royalty owners in our Oklahoma wells. We have asserted several defenses including that the case cannot be properly certified as a class action because of the wide variety of circumstances that determine whether a royalty payment was timely made or has accrued interest under Oklahoma law. The issue of class certification has not been heard by the court.

Chieftain Royalty Company v. Unit Petroleum Company, No. CJ-16-230, District Court of LeFlore County, Oklahoma.

On November 3, 2016, a putative class action lawsuit was filed against Unit Petroleum Company styled *Chieftain Royalty Company v. Unit Petroleum Company* in LeFlore County, Oklahoma. Plaintiff alleges that Unit Petroleum breached its duty to pay royalties on natural gas used for fuel off the lease premises. The lawsuit seeks actual and punitive damages, an accounting, injunctive relief, and attorney's fees. Plaintiff is seeking relief on behalf of Oklahoma citizens who are or were royalty owners in our Oklahoma wells. We filed a motion to dismiss on the basis that the claims asserted by the Plaintiff and the putative class are barred because they have already been asserted by the putative class in the Panola lawsuit and are subject to its reversal of class certification. The court denied our motion to dismiss and we have asked the court to certify its order so that it can be immediately appealed. That issue is still pending before the court. If we do not ultimately prevail on our claim of issue preclusion, we have several other defenses, including that the case cannot be properly certified as a class action because of the

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wide variety of circumstances that determine whether a royalty payment was wrongfully withheld. The issue of class certification has not been heard by the court.

We continue to vigorously defend against each of the pending claims. At this time we are unable to express an opinion with respect to the likelihood of an unfavorable outcome or provide an estimate of potential losses, if any.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market for the Registrant's Common Equity, Related Stockholder Matters, and Issuer Purchases of Equity Securities

Our common stock trades on the New York Stock Exchange under the symbol "UNT." The high and low closing sales prices per share of our common stock can be easily accessed for free on numerous websites.

On February 12, 2019, the closing sale price of our common stock, as reported by the NYSE, was $15.55 per share. On that date, there were approximately 738 holders of record of our common stock.

We have declared no cash dividends on our common stock. Any future determination by our board of directors to pay dividends on our common stock will be made only after considering our financial condition, results of operations, capital requirements, and other relevant factors. Our bank credit agreements and the Notes prohibit the payment of cash dividends on our common stock under certain circumstances. For further information regarding our bank credit agreements and the Notes agreement's impact on our ability to pay dividends see "Our Credit Agreements and Senior Subordinated Notes" under Item 7 of this report.

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Performance Graph. The following graph and related information shall not be deemed “soliciting material” or be deemed to be “filed” with the SEC, nor will this information be incorporated by reference into any future filing, except to the extent that we specifically incorporate it by reference into that filing.

Set forth below is a line graph comparing the cumulative total shareholder return on our common stock with the cumulative total return of the S&P 500 Stock Index, S&P 600 Oil and Gas Exploration & Production, and a peer group chosen by us. We changed our peer group for the performance graph to align with the 2018 peer group used by the compensation committee of our board of directors. Our new peer group consists of Cabot Oil & Gas Corp., Carrizo Oil & Gas, Inc., Cimarex Energy Co., Denbury Resources, Inc., Helmerich & Payne, Inc., Laredo Petroleum, Inc., Newfield Exploration Co., Oasis Petroleum, Inc., Parker Drilling Co., Patterson-UTI Energy, Inc., PDC Energy, Inc., Pioneer Energy Services Corp., SM Energy Co., Whiting Petroleum Corp., and WPX Energy, Inc. Our old peer group consisted of Helmerich & Payne, Inc., Patterson – UTI Energy Inc., and Pioneer Energy Services Corp. We decided to use the new peer group because we measure our performance against theirs to determine components of our executives’ compensation, and we believe that the new peer group better reflects the diversified nature of our energy operations than the old peer group. The graph below assumes an investment of $100 at the beginning of the period. The shareholder return set forth below is not necessarily indicative of future performance.

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Item 6. Selected Financial Data

The following table shows selected consolidated financial data. The data should be read in conjunction with Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations," for a review of 2018, 2017, and 2016 activity.

	As of and for the Year Ended December 31,				
	2018	2017	2016	2015	2014
	(In thousands except per share amounts)				
Revenues	$ 843,281	$ 739,640	$ 602,177	$ 854,231	$ 1,572,944
Net income (loss) attributable to Unit Corporation	(45,288) (4)	117,848	(135,624) (3)	$ (1,037,361) (2)	$ 136,276 (1)
Net income (loss) attributable to Unit Corporation per common share:					
Basic	$ (0.87)	$ 2.31	$ (2.71)	$ (21.12)	$ 2.80
Diluted	$ (0.87)	$ 2.28	$ (2.71)	$ (21.12)	$ 2.78
Total assets	$ 2,698,053 (4)	$ 2,581,452	$ 2,479,303 (3)	$ 2,799,842 (2)	$ 4,463,473 (1)
Long-term debt (5)	$ 644,475	$ 820,276	$ 800,917	$ 918,995	$ 801,908
Other long-term liabilities (6)	$ 101,527	$ 100,203	$ 103,479	$ 140,626	$ 148,785
Cash dividends per common share	$ —	$ —	$ —	$ —	$ —

1.In December 2014, we incurred a non-cash ceiling test write-down of our oil and natural gas properties of $76.7 million pre-tax ($47.7 million, net of tax), a non-cash write-down associated with the removal of 31 drilling rigs from our fleet along with certain other equipment and drill pipe of $74.3 million pre-tax ($46.3 million, net of tax), and a non-cash write-down associated with a reduction in the carrying value of three mid-stream segment systems of $7.1 million pre-tax ($4.4 million, net of tax).

2.In total for 2015, we incurred non-cash ceiling test write-downs on our oil and natural gas properties of $1.6 billion pre-tax ($1.0 billion, net of tax). We also incurred a non-cash write-down on certain drilling rigs and other equipment of approximately $8.3 million pre-tax ($5.1 million, net of tax), and a non-cash write-down associated with a reduction in the carrying value of three mid-stream segment systems of $27.0 million pre-tax ($16.8 million, net of tax).

3.For the first three quarters of 2016, we incurred non-cash ceiling test write-downs on our oil and natural gas properties of $161.6 million pre-tax ($100.6 million, net of tax).

4.In December 2018, we incurred a non-cash write-down associated with the removal of 41 drilling rigs from our fleet of $147.9 million pre-tax ($111.7 million, net of tax).

5.Long-term debt is net of unamortized discount and debt issuance costs.

6.Includes non-current derivative liabilities, if any.

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Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Please read this discussion of our financial condition and results of operations with the consolidated financial statements and related notes in Item 8 of this report.

General

We were founded in 1963 as a contract drilling company. Today, we operate, manage, and analyze our results of operations through our three principal business segments:

•*Oil and Natural Gas* – carried out by our subsidiary Unit Petroleum Company. This segment explores, develops, acquires, and produces oil and natural gas properties for our own account.
•*Contract Drilling* – carried out by our subsidiary Unit Drilling Company. This segment contracts to drill onshore oil and natural gas wells for others and for our own account.
•*Mid-Stream* – carried out by our subsidiary Superior Pipeline Company, L.L.C. and its subsidiaries. This segment buys, sells, gathers, processes, and treats natural gas for third parties and for our own account. We own 50% of this subsidiary.

Business Outlook

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The number of gross wells our oil and gas segment drilled in 2018 verses 2017 increased from 70 wells to 117 wells due to increased cash flow. For 2019, we plan to decrease the number of gross wells drilled to 90-100 wells (depending on future commodity prices).

During 2018, due to low ethane and residue prices, we operated some of our mid-stream processing facilities in ethane rejection mode which reduces the liquids sold. At the end of 2018 and into the first part of 2019, as NGLs and gas prices

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improved, we began operating some of our mid-stream processing facilities in ethane recovery mode. We are continuing to monitor commodity prices to determine the most economical method in which to operate our processing facilities.

In December 2018, we closed on an acquisition of certain oil and natural gas assets located primarily in Custer County, Oklahoma. The total preliminary adjusted value of consideration given was $29.6 million. As of November 1, 2018, the effective date of the acquisition, the estimated proved oil and gas reserves for the acquired properties was 2.6 MMBoe net to Unit. The acquisition added approximately 8,667 net oil and gas leasehold acres to our Penn Sands area in Oklahoma including approximately 44 wells. The acquisitions included approximately 30 potential horizontal drilling locations which are anticipated to have a high percentage of oil relative to the total production stream. Of the acreage acquired, approximately 82% was held by production.

Executive Summary

Oil and Natural Gas

Fourth quarter 2018 production from our oil and natural gas segment was 4,318 MBoe, a decrease of 1% from the third quarter of 2018 and was essentially unchanged from the fourth quarter of 2017. The decrease from the third quarter came from fewer net wells being completed in the fourth quarter. Oil and NGLs production was 46% of our total production during both the fourth quarter of 2018 and the fourth quarter of 2017.

Fourth quarter 2018 oil and natural gas revenues decreased 5% from the third quarter of 2018 and increased 4% over the fourth quarter of 2017. The decrease from the third quarter was primarily due to a decrease in production and decrease in oil and NGL prices partially offset by an increase in natural gas prices. The increase over the fourth quarter 2017 was primarily due to higher unhedged natural gas prices and higher oil and natural gas production volumes.

Our hedged natural gas prices for the fourth quarter of 2018 increased 22% and 16% over third quarter of 2018 and fourth quarter of 2017, respectively. Our hedged oil prices for the fourth quarter of 2018 decreased 6% and 1% from the third quarter of 2018 and the fourth quarter of 2017, respectively. Our hedged NGLs prices for the fourth quarter of 2018 decreased 24% and 10% from the third quarter of 2018 and fourth quarter of 2017, respectively.

Direct profit (oil and natural gas revenues less oil and natural gas operating expense) decreased 6% from the third quarter of 2018 and increased 12% over the fourth quarter of 2017. The decrease from the third quarter of 2018 was primarily due to a decrease in production, a decrease in oil and NGLs prices, and an increase in lease operating expenses (LOE) partially offset by an increase in natural gas prices. The increase over the fourth quarter of 2017 was primarily due to higher revenues due to rising unhedged oil and natural gas prices and increased oil and natural gas production volumes.

Operating cost per Boe produced for the fourth quarter of 2018 decreased 2% from the third quarter of 2018 and decreased 11% from the fourth quarter of 2017. The decrease from the the third quarter of 2018 was primarily due to lower gross production taxes due to tax credits received and decrease tax from lower revenues and lower saltwater disposal expense partially offset by higher LOE and general and administrative (G&A) expenses net of geological and geophysical capitalized. The decrease from the fourth quarter of 2017 was primarily due to the reclass of deduction to revenues under ASC 606 offset partially by production that was essentially unchanged.

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At December 31, 2018, these non-designated hedges were outstanding:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price for Swaps	Contracted Market
Jan'19 – Mar'19	Natural gas – swap	50,000 MMBtu/day	$3.440	IF – NYMEX (HH)
Apr'19 – Dec'19	Natural gas – swap	40,000 MMBtu/day	$2.900	IF – NYMEX (HH)
Jan'19 – Dec'19	Natural gas – basis swap	20,000 MMBtu/day	$(0.659)	PEPL
Jan'19 – Dec'19	Natural gas – basis swap	10,000 MMBtu/day	$(0.625)	NGPL MIDCON
Jan'19 – Dec'19	Natural gas – basis swap	30,000 MMBtu/day	$(0.265)	NGPL TEXOK
Jan'20 – Dec'20	Natural gas – basis swap	30,000 MMBtu/day	$(0.275)	NGPL TEXOK
Jan'19 – Dec'19	Natural gas – collar	20,000 MMBtu/day	$2.63 - $3.03	IF – NYMEX (HH)
Jan'19 – Mar'19	Natural gas – three-way collar	30,000 MMBtu/day	$3.17 - $2.92 - $4.32	IF – NYMEX (HH)
Jan'19 – Dec'19	Crude oil – three-way collar	4,000 Bbl/day	$61.25 - $51.25 - $72.93	WTI – NYMEX

After December 31, 2018, these non-designated hedges were entered into:

Term	Commodity	Contracted Volume	Weighted Average Fixed Price for Swaps	Contracted Market
Apr'19 – Oct'19	Natural gas – swap	20,000 MMBtu/day	$2.900	IF – NYMEX (HH)

In our Wilcox play, located primarily in Polk, Tyler, Hardin, and Goliad Counties, Texas, we completed seven vertical and one horizontal well (average working interest 100%) in 2018, all of which were completed as gas/condensate producers. Annual production from our Wilcox play averaged 89 MMcfe per day (9% oil, 27% NGLs, 64% natural gas) which is a decrease of 2% compared to 2017. We averaged approximately 0.7 Unit drilling rigs operating during 2018 and we plan to use one Unit drilling rig during 2019. We anticipate completing approximately 13 vertical wells during 2019. In addition, we plan to complete approximately ten behind pipe gas and liquids zones.

In our Southern Oklahoma Hoxbar Oil Trend (SOHOT) play, in western Oklahoma primarily in Grady County, we completed seven horizontal oil wells (average working interest 77.6%) in the Marchand zone of the Hoxbar interval. In our Western STACK area, we completed two horizontal wells (average working interest 94.8%), and in our Thomas Field (Red Fork), we completed two horizontal wells (average working interest 79.2%). Annual production from western Oklahoma averaged 76.4 MMcfe per day (33% oil, 21% NGLs, 46% natural gas) which is an increase of approximately 26% compared to 2017. During 2018, we averaged approximately 1.4 Unit drilling rigs operating, and we currently plan to use approximately three Unit drilling rigs for the first half of 2019. We anticipate completing approximately eight horizontal Marchand wells in our SOHOT play and eight horizontal wells in our Red Fork play in Thomas Field during 2019. During 2018, we participated in 61 non-operated wells in the mid-continent region, with most of those occurring in the STACK play. Unit's average working interest in these wells is 3.7%.

In our Texas Panhandle Granite Wash play, we completed 12 extended lateral horizontal gas/condensate wells (average working interest 99.7%) in our Buffalo Wallow field. Annual production from the Texas Panhandle averaged 96.3 MMcfe per day (10% oil, 39% NGLs, 51% natural gas) which is an increase of approximately 11% compared to

2017. We used 1.3 Unit drilling rigs during 2018 and ww plan to operate one Unit drilling rig for the first four months of the year in 2019. We anticipate completing approximately four extended lateral Granite Wash horizontal wells in our Buffalo Wallow field during 2019.

In 2018, we performed two recompletions on existing wells in our Panola Field. Both recompletions were upper zones in the Lower Atoka formation. We also drilled one vertical well that targeted the Middle Atoka. We plan on drilling one vertical well in early 2019 that will target the Middle Atoka.

During 2018, we participated in the drilling of 117 wells (33.16 net wells). For 2019, we plan to participate in the drilling of approximately 90 to 100 gross wells. Our 2019 production guidance is approximately 17.4 to 17.9 MMBoe, an increase of 2-5% over 2018, actual results which will be subject to many factors. This segment’s capital budget for 2019 ranges from approximately $271.0 million to $315.0 million, a decrease of 21% to 9% from 2018, excluding acquisitions and ARO liability.

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Contract Drilling

The average number of drilling rigs we operated in the fourth quarter was 33.1 compared to 34.2 and 31.2 in the third quarter of 2018 and fourth quarter of 2017, respectively. As of December 31, 2018, 32 of our drilling rigs were operating.

Revenue for the fourth quarter of 2018 increased 5% over the third quarter of 2018 and increased 14% over the fourth quarter of 2017. The increase over the third quarter of 2018 was primarily due to higher dayrates partially offset by fewer drilling rigs operating. The increase over the fourth quarter of 2017 was primarily due to more drilling rigs operating and higher dayrates.

Dayrates for the fourth quarter of 2018 averaged $18,047, a 3% increase over the third quarter of 2018 and an 8% increase over the fourth quarter of 2017. The increase over the third quarter of 2018 was primarily due to general increases with the improving market and the addition of a BOSS drilling rig. The increase over the fourth quarter of 2017 was primarily due to two labor increases passed through to contracted rig rates and improving market dayrates.

Operating costs for the fourth quarter of 2018 increased 12% over the third quarter of 2018 and increased 14% over the fourth quarter of 2017. The increase over the third quarter of 2018 was primarily due to a decrease in eliminations with a lower percentage of our drilling rig usage coming from our oil and gas segment and increased indirect and G&A expenses, partially offset by decreased direct cost with decrease utilization. The increase over the fourth quarter of 2017 was primarily due to more drilling rigs operating and increased per day cost.

Direct profit (contract drilling revenue less contract drilling operating expense) for the fourth quarter of 2018 decreased 8% from the third quarter of 2018 and increased 12% over the fourth quarter of 2017. The decrease from the third quarter of 2018 was primarily due to fewer drilling rigs operating and increased indirect and drilling G&A expenses while the increase over the fourth quarter of 2017 was primarily due to more drilling rigs operating.

Operating cost per day for the fourth quarter of 2018 increased 15% over the third quarter of 2018 and increased 8% over the fourth quarter of 2017. The increase over the third quarter of 2018 was primarily due to decreased eliminations with a lower percentage of our drilling rig usage coming from our oil and gas segment and higher per day indirect and G&A costs. The increase over the fourth quarter of 2017 was primarily due to more rigs operating.

In December 2018, our Board of Directors approved a plan to sell 41 drilling rigs (29 mechanical drilling rigs and 12 SCR diesel-electric drilling rigs) and other equipment. This plan satisfies the criteria of assets held for sale under ASC 360-10-45-9. Over the last five years, only six of our drilling rigs in the fleet have not been utilized. We made a strategic decision to focus on our new BOSS drilling rigs and specific SCR drilling rigs (good candidates for modification) and sell the other drilling rigs that we now choose not to market. We estimated the fair value of the 41 drilling rigs we will no longer market based on the estimated market value from third-party assessments (Level 3 fair value measurement) less cost to sell. Based on these estimates, we recorded a non-cash write-down of approximately $147.9 million, pre-tax ($111.7 million, net of tax).

The contract drilling segment has operations in Oklahoma, Texas, Louisiana, Kansas, Colorado, Utah, Wyoming, Montana and North Dakota. As of December 31, 2018, 18 rigs were working in Oklahoma and the Texas Panhandle, one in East Texas, and six in the Permian Basin of West Texas, two drilling rigs in Wyoming and five drilling rigs in the Bakken Shale of North Dakota.

During 2018, almost all of our working drilling rigs were drilling horizontal or directional wells for oil and NGLs. The future demand for and the availability of drilling rigs to meet that demand will affect our future dayrates.

As of December 31, 2018, we had 24 term drilling contracts with original terms ranging from six months to three years. Seventeen of these contracts are up for renewal in 2019, (seven in the first quarter, seven in the second quarter, one in the third quarter, and two in the fourth quarter) and seven are up for renewal in 2020 and beyond. Term contracts may contain a fixed rate during the contract or provide for rate adjustments within a specific range from the existing rate. Some operators who had signed term contracts have opted to release the drilling rig and pay an early termination penalty for the remaining term of the contract. We recorded $0.1 million, $0.8 million, and $3.1 million in early termination fees in 2018, 2017, and 2016, respectively. In the first quarter of 2019, we recorded $4.6 million in early termination fees.

All 13 of our existing BOSS drilling rigs are under contract.

All of our contracts are daywork contracts.

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Our anticipated 2019 capital expenditures for this segment ranges from approximately $30.0 million to $65.0 million, a 60% to 14% decrease from 2018.

Mid-Stream

Fourth quarter 2018 liquids sold per day was essentially unchanged from the third quarter of 2018 and increased 20% over the fourth quarter of 2017. The increase over the fourth quarter of 2017 was due primarily to more processed volume from connecting additional wells to our systems. For the fourth quarter of 2018, gas processed per day was essentially unchanged from the third quarter of 2018 and increased 8% over the fourth quarter of 2017. The increase over the fourth quarter of 2017 was due to connecting additional wells to our processing systems. For the fourth quarter of 2018, gas gathered per day decreased 5% from the third quarter of 2018 and increased 3% over the fourth quarter of 2017. The decrease from the third quarter of 2018 was primarily due to declining volumes from the Appalachian region and the increase over the fourth quarter of 2017 was mainly due to connecting the infill wells on the Pittsburgh Mills gathering system.

NGLs prices in the fourth quarter of 2018 decreased 20% and 23% from the prices received in the third quarter of 2018 and the fourth quarter of 2017, respectively. Because certain of the contracts used by our mid-stream segment for NGLs transactions are commodity-based contracts – under which we receive a share of the proceeds from the sale of the NGLs – our revenues from those commodity-based contracts fluctuate based on NGLs prices.

Direct profit (mid-stream revenues less mid-stream operating expense) for the fourth quarter of 2018 decreased 16% and 5% from the third quarter of 2018 and fourth quarter of 2017, respectively. The decrease from the third quarter of 2018 was primarily due to lower NGLs and condensate prices. The decrease from the fourth quarter of 2017 was primarily due to the increased revenues from the timing of demand fees recognition under ASC 606 along with a decrease in NGLs prices. Total operating cost for this segment for the fourth quarter of 2018 increased 1% over the third quarter of 2018 and decreased 1% from the fourth quarter of 2017. The increase over the third quarter of 2018 was primarily due to a decrease from the third quarter of 2018 in purchases made from our oil and gas segment that was eliminated and the increase over the fourth quarter of 2017 was due primarily to higher field direct operating expenses.

In the Appalachian region at the Pittsburgh Mills gathering system, average gathered volume for the fourth quarter of 2018 was approximately 129.7 MMcf per day and the annual average gathered volume was 123.9 MMcf per day. In 2018, we added seven new infill wells late in the second quarter and all the new infill wells are currently online and flowing gas. We have completed construction of the new pipeline to connect the next scheduled well pad to our system. We have also completed the upgrade of the compressor station and dehydration facilities. Production from this new pad started online during January 2019.

At the Hemphill Texas system, average total throughput volume for the fourth quarter of 2018 increased to 75.3 MMcf per day and total production of natural gas liquids was approximately 301,500 gallons per day during this same period. The annual average throughput volume was 72.6 MMcf per day while the annual total production of natural gas liquids averaged 264,971 gallons per day. During the fourth quarter, we connected five new wells in the Buffalo Wallow area. These new wells along with increased production from recently drilled wells in this area contributed to the increased throughput volume. Our oil and gas segment continues to operate a rig in the Buffalo Wallow area and we anticipate connecting additional wells to this system in 2019.

At the Cashion processing facility in central Oklahoma, total throughput volume for the fourth quarter of 2018 averaged approximately 49.2 MMcf per day and total production of natural gas liquids increased to 246,873 gallons per day. The annual average throughput volume was 46.0 MMcf per day and the annual average natural gas liquids production was 234,316 gallons per day. This system is currently operating at full processing capacity and we are adding additional capacity to this system. We are relocating a 60 MMcf per day processing plant from our Bellmon facility to the Cashion area. This processing plant will be installed at the Reeding site on the Cashion system. This plant is expected to be operational by the end of the first quarter of 2019 and it will increase our total processing capacity on the Cashion system to approximately 105 MMcf per day. We connected eight new wells to this system during the fourth quarter of 2018 and we are continuing to connect additional wells from a third party producer who continues to be active in this area.

At the Minco processing facility in central Oklahoma, total throughput volume for the fourth quarter of 2018 was approximately 8.0 MMcf per day and the average annual total throughput volume was 9.5 MMcf per day. During the fourth quarter of 2018 we completed a new interconnect with a producer who is currently delivering gas to our system. Additionally, we are completing construction of a new well connect for a third party producer who is expected to deliver gas to our system in 2019. The current processing capacity of the Minco facility is approximately 12 MMcf per day.

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Anticipated 2019 capital expenditures for this segment range from approximately $35.0 million to $42.0 million, a 22% to 6% decrease from 2018.

Critical Accounting Policies and Estimates

Summary

In this section, we identify those critical accounting policies we follow in preparing our financial statements and related disclosures. Many policies require us to make difficult, subjective, and complex judgments while making estimates of matters inherently imprecise. Some accounting policies involve judgments and uncertainties to such an extent there is reasonable likelihood that materially different amounts could have been reported under different conditions, or had different assumption been used. We evaluate our estimates and assumptions regularly. We base our estimates on historical experience and various other assumptions we believe are reasonable under the circumstances, the results of which support making judgments about the carrying values of assets and liabilities not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our financial statements. In this discussion we attempt to explain the nature of these estimates, assumptions and judgments, and the likelihood that materially different amounts would be reported in our financial statements under different conditions or using different assumptions.

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This table lists the critical accounting policies, identifies the estimates and assumptions that can have a significant impact on applying these accounting policies, and the financial statement accounts affected by these estimates and assumptions.

Accounting Policies	**Estimates or Assumptions**	**Accounts Affected**
Full cost method of accounting for oil, NGLs, and natural gas properties	• Oil, NGLs, and natural gas reserves, estimates, and related present value of future net revenues • Valuation of unproved properties • Estimates of future development costs	• Oil and natural gas properties • Accumulated depletion, depreciation and amortization • Provision for depletion, depreciation and amortization • Impairment of oil and natural gas properties • Long-term debt and interest expense
Accounting for ARO for oil, NGLs, and natural gas properties	• Cost estimates related to the plugging and abandonment of wells • Timing of cost incurred • Credit adjusted risk free rate	• Oil and natural gas properties • Accumulated depletion, depreciation and amortization • Provision for depletion, depreciation and amortization • Current and non-current liabilities • Operating expense
Accounting for material producing property and undeveloped acreage acquisitions	•Value the reserves with the income approach using cash flow projections •Value the undeveloped acreage with the market approach using comparable sales data •Value equipment with the market approach using comparable sales data and CEPS pricing	• Oil and natural gas properties • Non-current liabilities

Accounting for impairment of long-lived assets	• Forecast of undiscounted estimated future net operating cash flows	• Drilling and mid-stream property and equipment • Accumulated depletion, depreciation and amortization • Provision for depletion, depreciation and amortization
Goodwill	• Forecast of discounted estimated future net operating cash flows • Terminal value • Weighted average cost of capital	• Goodwill
Accounting for value of stock compensation awards	• Estimates of stock volatility • Estimates of expected life of awards granted • Estimates of rates of forfeitures • Estimates of performance shares granted	• Oil and natural gas properties • Shareholder's equity • Operating expenses • General and administrative expenses
Accounting for derivative instruments	• Derivatives measured at fair value	• Current and non-current derivative assets and liabilities • Gain (loss) on derivatives

Significant Estimates and Assumptions

Full Cost Method of Accounting for Oil, NGLs, and Natural Gas Properties. Determining our oil, NGLs, and natural gas reserves is a subjective process. It entails estimating underground accumulations of oil, NGLs, and natural gas that cannot be measured in an exact manner. Accuracy of these estimates depends on several factors, including, the quality and availability of geological and engineering data, the precision of the interpretations of that data, and individual judgments. Each year, we hire an independent petroleum engineering firm to audit our internal evaluation of our reserves. The audit of our reserve wells or locations as of December 31, 2018 covered those that we projected to comprise 83% of the total proved developed future net income discounted at 10% and 82% of the total proved discounted future net income (based on the SEC's unescalated pricing policy). Included in Part I, Item 1 of this report are the qualifications of our independent petroleum engineering firm and our employees responsible for preparing our reserve reports.

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As a rule, the accuracy of estimating oil, NGLs, and natural gas reserves varies with the reserve classification and the related accumulation of available data, as shown in this table:

Type of Reserves	Nature of Available Data	Degree of Accuracy
Proved undeveloped	Data from offsetting wells, seismic data	Less accurate
Proved developed non-producing	The above and logs, core samples, well tests, pressure data	More accurate
Proved developed producing	The above and production history, pressure data over time	Most accurate

Assumptions of future oil, NGLs, and natural gas prices and operating and capital costs also play a significant role in estimating these reserves and the estimated present value of the cash flows to be received from the future production of those reserves. Volumes of recoverable reserves are influenced by the assumed prices and costs due to the economic limit (that point when the projected costs and expenses of producing recoverable oil, NGLs, and natural gas reserves are greater than the projected revenues from the oil, NGLs, and natural gas reserves). But more significantly, the estimated present value of the future cash flows from our oil, NGLs, and natural gas reserves is sensitive to prices and costs and may vary materially based on different assumptions. Companies, like ours, using full cost accounting use the unweighted arithmetic average of the commodity prices existing on the first day of each of the 12 months before the end of the reporting period to calculate discounted future revenues, unless prices were otherwise determined under contractual arrangements.

We compute DD&A on a units-of-production method. Each quarter, we use these formulas to compute the provision for DD&A for our producing properties:

•DD&A Rate = Unamortized Cost / End of Period Reserves Adjusted for Current Period Production
•Provision for DD&A = DD&A Rate x Current Period Production

Unamortized cost includes all capitalized costs, estimated future expenditures to be incurred in developing proved reserves and estimated dismantlement and abandonment costs, net of estimated salvage values less accumulated amortization, unproved properties, and equipment not placed in service.

Oil, NGLs, and natural gas reserve estimates have a significant impact on our DD&A rate. If future reserve estimates for a property or group of properties are revised downward, the DD&A rate will increase because of the revision. If reserve estimates are revised upward, the DD&A rate will decrease. Based on our 2018 production level of 17.1 MMBoe, a decrease in our 2018 oil, NGLs, and natural gas reserves by 5% would increase our DD&A rate by $0.42 per Boe and would decrease pre-tax income by $7.2 million annually. Conversely, an increase in our 2018 oil, NGLs, and natural gas reserves by 5% would decrease our DD&A rate by $0.36 per Boe and would increase pre-tax income by $6.1 million annually.

The DD&A expense on our oil and natural gas properties is calculated each quarter using period end reserve quantities adjusted for period production.

We account for our oil and natural gas exploration and development activities using the full cost method of accounting. Under this method, we capitalize all costs incurred in the acquisition, exploration, and development of oil and natural gas properties. At the end of each quarter, the net capitalized costs of our oil and natural gas properties are limited to that amount which is the lower of unamortized costs or a ceiling. The ceiling is defined as the sum of the present value (using a 10% discount rate) of the estimated future net revenues from our proved reserves (based on the unescalated 12-month average price on our oil, NGLs, and natural gas adjusted for any cash flow hedges), plus the cost of properties not being amortized, plus the lower of the cost or estimated fair value of unproved properties included in the costs being amortized, less related income taxes. If the net capitalized costs of our oil and natural gas properties exceed the ceiling, we are required to write-down the excess amount. A ceiling test write-down is a non-cash charge to earnings. If required, it reduces earnings and impacts shareholders' equity in the period of occurrence and results in lower DD&A expense in future periods. Once incurred, a write-down cannot be reversed.

The risk we will be required to write-down the carrying value of our oil and natural gas properties increases when the prices for oil, NGLs, and natural gas are depressed or if we have large downward revisions in our estimated proved oil, NGLs, and natural gas reserves. Application of these rules during periods of relatively low prices, even if temporary, increases the chance of a ceiling test write-down. At December 31, 2018, our reserves were calculated based on applying 12-month 2018

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average unescalated prices of $65.56 per barrel of oil, $37.68 per barrel of NGLs, and $3.10 per Mcf of natural gas (then adjusted for price differentials) over the estimated life of each of our oil and natural gas properties. We had no ceiling test write-down for 2018.

It is hard to predict with any reasonable certainty the need for or amount of any future impairments given the many factors that go into the ceiling test calculation including future pricing, operating costs, drilling and completion costs, upward or downward oil and gas reserve revisions, oil and gas reserve additions, and tax attributes. Subject to these inherent uncertainties, if we hold these same factors constant as they existed at December 31, 2018 and only adjust the 12-month average price to an estimated first quarter ending average (holding February 2019 prices constant for the remaining one month of the first quarter of 2019), our forward looking expectation is that we will not recognize an impairment in the first quarter of 2019. But commodity prices (and other factors) remain volatile and they could negatively affect the 12-month average price resulting in the potential for an impairment in the first quarter.

, which may be more or less than our share of pro-rata production from certain wells. Our policy is to expense our pro-rata share of lease operating costs from all wells as incurred. The expenses relating to the wells in which we have a production imbalance are not material.

Costs Withheld from Amortization. Costs associated with unproved properties are excluded from our amortization base until we have evaluated the properties. The costs associated with unevaluated leasehold acreage and related seismic data, the drilling of wells, and capitalized interest are initially excluded from our amortization base. Leasehold costs are transferred to our amortization base with the costs of drilling a well on the lease or are assessed at least annually for possible impairment or reduction in value. Leasehold costs are transferred to our amortization base to the extent a reduction in value has occurred.

Our decision to withhold costs from amortization and the timing of transferring those costs into the amortization base involve significant judgment and may be subject to changes over time based on several factors, including our drilling plans, availability of capital, project economics and results of drilling on adjacent acreage. In December 2016 and December 2017, we determined the value of certain unproved oil and gas properties were diminished (in part or in whole) based on an impairment evaluation and our anticipated future exploration plans. Those determinations resulted in $7.6 million and $10.5 million in 2016 and 2017, respectively of costs being added to the total of our capitalized costs being amortized. We did not have any in 2018. At December 31, 2018, we had approximately $330.2 million of costs excluded from the amortization base of our full cost pool.

Accounting for ARO for Oil, NGLs, and Natural Gas Properties. We record the fair value of liabilities associated with the future plugging and abandonment of wells. In our case, when the reserves in each of our oil or gas wells deplete or otherwise become uneconomical, we must incur costs to plug and abandon the wells. These costs are recorded in the period in which the liability is incurred (at the time the wells are drilled or acquired). We have no assets restricted to settle these ARO liabilities. Our engineering staff uses historical experience to determine the estimated plugging costs considering the type of well (either oil or natural gas), the depth of the well, the physical location of the well, and the ultimate productive life to determine the estimated plugging costs. A risk-adjusted discount rate and an inflation factor are used on these estimated costs to determine the current present value of this obligation. To the extent any change in these assumptions affect future revisions and impact the present value of the existing ARO, a corresponding adjustment is made to the full cost pool.

Accounting for Impairment of Long-Lived Assets. Drilling equipment, transportation equipment, gas gathering and processing systems, and other property and equipment are carried at cost less accumulated depreciation. Renewals and enhancements are capitalized while repairs and maintenance are expensed. We review the carrying amounts of long-lived assets for potential impairment annually, typically during the fourth quarter, or when events occur or changes in circumstances suggest these carrying amounts may not be recoverable. Changes that could prompt such an assessment may include equipment obsolescence, changes in the market demand for a specific asset, changes in commodity prices, periods of relatively low drilling rig utilization, declining revenue per day, declining cash margin per day, or overall changes in market conditions. Assets are determined to be impaired if a forecast of undiscounted estimated future net operating cash flows directly related to the asset, including disposal value if any, is less than the carrying amount of the asset. If any asset is determined to be impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value. The estimate of fair value is based on the best information available, including prices for similar assets. Changes in these estimates could cause us to reduce the carrying value of property and equipment. Asset impairment evaluations are, by nature, highly subjective. They involve expectations about future cash flows generated by our assets and reflect management's assumptions and judgments regarding future industry conditions and their effect on future utilization levels, dayrates, and costs. Using different estimates and assumptions could cause materially different carrying values of our assets.

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On a periodic basis, we evaluate our fleet of drilling rigs for marketability based on the condition of inactive rigs, expenditures that would be necessary to bring them to working condition and the expected demand for drilling services by rig type. The components comprising inactive rigs are evaluated, and those components with continuing utility to the Company's other marketed rigs are transferred to other rigs or to its yards to be spare equipment. The remaining components of these rigs are retired. No impairments were recorded in 2016 or 2017. In December 2018, our Board of Directors approved a plan to sell 41 drilling rigs (29 mechanical drilling rigs and 12 SCR diesel-electric drilling rigs) and other equipment. This plan satisfies the criteria of assets held for sale under ASC 360-10-45-9. Over the last five years, only six of our drilling rigs in the fleet have not been utilized. We made a strategic decision to focus on our new BOSS drilling rigs and specific SCR drilling rigs (good candidates for modification) and sell the other drilling rigs that we now choose not to market. We estimated the fair value of the 41 drilling rigs we will no longer market based on the estimated market value from third-party assessments (Level 3 fair value measurement) less cost to sell. Based on these estimates, we recorded a non-cash write-down of approximately $147.9 million, pre-tax ($111.7 million, net of tax).

Goodwill. Goodwill represents the excess of the cost of acquisitions over the fair value of the net assets acquired. Goodwill is not amortized, but an impairment test is performed at least annually to determine whether the fair value has decreased and is performed additionally when events indicate an impairment may have occurred. For impairment testing, goodwill is evaluated at the reporting unit level. Our goodwill is all related to our contract drilling segment, and, the impairment test is generally based on the estimated discounted future net cash flows of our drilling segment, utilizing discount rates and other factors in determining the fair value of our drilling segment. Inputs in our estimated discounted future net cash flows include drilling rig utilization, day rates, gross margin percentages, and terminal value. No goodwill impairment was recorded at December 31, 2018, 2017, or 2016. Based on our impairment test performed as of December 31, 2018, the fair value of our drilling segment exceeded its carrying value by 37%. While the goodwill of this reporting unit is not currently impaired, there could be an impairment in the future as a result of changes in certain assumptions. For example, the fair value could be adversely affected and result in an impairment of goodwill if we do not realize the anticipated drilling rig utilization of the anticipated drilling rig dayrates, or if the estimated cash flows are discounted at a higher risk-adjusted rate or market multiples decrease.

*Drilling Contracts.*The type of contract used determines our compensation. All of our contracts in 2018, 2017, and 2016 were daywork contracts. Under a daywork contract, we provide the drilling rig with the required personnel and the operator supervises the drilling of the well. Our compensation is based on a negotiated rate to be paid for each day the drilling rig is used.

Accounting for Value of Stock Compensation Awards. To account for stock-based compensation, compensation cost is measured at the grant date based on the fair value of an award and is recognized over the service period, which is usually the vesting period. We elected to use the modified prospective method, which requires compensation expense to be recorded for all unvested stock options and other equity-based compensation beginning in the first quarter of adoption. Determining the fair value of an award requires significant estimates and subjective judgments regarding, among other things, the appropriate option pricing model, the expected life of the award and performance vesting criteria assumptions. As there are inherent uncertainties related to these factors and our judgment in applying them to the fair value determinations, there is risk that the recorded stock compensation may not accurately reflect the amount ultimately earned by the employee.

Accounting for Derivative Instruments and Hedging. All derivatives are recognized on the balance sheet and measured at fair value. Any changes in our derivatives' fair value before their maturity (i.e., temporary fluctuations in value) along with any derivatives settled are reported in gain (loss) on derivatives in our Consolidated Statements of Operations.

New Accounting Standards

Fair Value Measurement (Topic 820): Disclosure Framework—Changes to the Disclosure Requirements for Fair Value Measurement. The FASB issued ASU 2018-13 to modify the disclosure requirements in Topic 820. Part of the disclosures were removed or modified and other disclosures were added. The amendment will be effective for reporting periods beginning after December 15, 2019. Early adoption is permitted. Also it is permitted to early adopt any removed or modified disclosure and delay adoption of the additional disclosures until their effective date. This amendment will not have a material impact on our financial statements.

*Compensation—Stock Compensation: Improvements to Nonemployee Share-Based Payment Accounting. T*he FASB issued ASU 2018-07, to improve financial reporting for nonemployee share-based payments. The amendment expands Topic 718, Compensation—Stock Compensation to include share-based payments issued to nonemployees for goods or services. The amendment will be effective for years beginning after December 15, 2019, and interim periods within those years. This amendment will not have a material impact on our financial statements.

Intangibles—Goodwill and Other: Simplifying the Test for Goodwill Impairment. The FASB issued ASU 2017-04, to simplify the measurement of goodwill. The amendment eliminates Step 2 from the goodwill impairment test. The amendment will be effective prospectively for reporting periods beginning after December 15, 2019, and early adoption is permitted. This amendment will not have a material impact on our financial statements.

Leases. The FASB has issued several accounting standards updates and amendments related to leases in the past two years, which are codified within Topic 842. For public companies, these are effective for annual periods beginning after December 15, 2018, and interim periods within those annual periods. The standard requires lessees to recognize at the commencement date of a lease a lease liability, which represents the lessee's obligation to make lease payments arising from the lease, measured on a discounted basis; and a right-of-use asset, which represents the lessee's right to use a specified asset for the lease term. Other recently issued amendments to Topic 842 have provided clarifying guidance regarding land easements, an additional modified retrospective transition method, and added several practical expedients to apply Topic 842 for both lessees and lessors. The standard will not apply to leases of mineral rights.

We have an implementation team working through the provisions of the new guidance including a review of different types of contracts to document our lease portfolio and assess the impact on our accounting, disclosures, processes, internal control over financial reporting, and the election of certain practical expedients. Our evaluation of the impact of the new guidance is substantially complete.

We have made certain accounting policy decisions including that we plan to adopt the short-term lease recognition exemption, accounting for certain asset classes at a portfolio level, and establishing a balance sheet recognition capitalization threshold. Our transition will utilize the modified retrospective approach to adopting the new standard, and will be applied at the beginning of the period adopted (January 1, 2019) in accordance with ASU 2018-11. We have elected the transition practical expedient, which allows us to not evaluate land easements that existed prior to January 1, 2019, and the optional transition method to record the our immaterial adoption impact through a cumulative adjustment to equity. We expect for certain lessee asset classes to elect the practical expedient and not separate lease and nonlease components. For these asset classes, we will account for the agreements as a single lease component.

We have determined that Unit Drilling Company lessor drilling rig contracts will be accounted for under ASC 606 as the service has been deemed the predominate component of the contract.

For both lessee and lessor practical expedients, we considered quantitative and qualitative factors when determining if an asset class qualified for the application of the practical expedient.

The adoption of this guidance will result in the addition of right-of-use assets and corresponding lease obligations to the consolidated balance sheet and will not have a material impact on the Company's results of operations or cash flows. Upon adoption, the Company expects to record operating lease right-of-use assets and the corresponding operating lease liabilities in the range of approximately $3.0 million to $4.5 million, representing the present value of future lease payments under operating leases. The Company is in the process of finalizing its catalog of existing lease contracts and implementing changes to its processes. There would be no impact to the Superior credit agreement debt covenants and an immaterial impact to the Unit credit agreement debt covenants as a result of adopting this standard.

Adopted Standards

As of January 1, 2018, we adopted ASU 2018-02 Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income. This standard is explained further in Note 8 - New Accounting Pronouncements. We adopted this amendment early and it had no material effect to our financial statements. We previously used 37.75% to calculate the tax effect on AOCI and we now use 24.5%. This change is reflected in our Consolidated Statements of Comprehensive Income and in Note 17 - Equity.

Also, as of January 1, 2018, we adopted ASU 2014-09 Revenue from Contracts with Customers - Topic 606 (ASC 606) and all later amendments that modified ASC 606. This new revenue standard is explained further in Note 8 – New Accounting Pronouncements. We elected to apply this standard on the modified retrospective approach method to contracts not completed as of January 1, 2018, where the cumulative effect on adoption, which only affected our mid-stream segment, is recognized as an adjustment to opening retained earnings at January 1, 2018. This adjustment related to the timing of revenue recognition for

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certain demand fees. Our oil and natural gas and contract drilling segments had no retained earnings adjustment. Comparative prior periods have not been adjusted and continue to be reported under ASC 605.

The additional disclosures required by ASC 606 have been included in Note 3 – Revenue from Contracts with Customers.

Our internal control framework did not materially change because of this standard, but the existing internal controls have been modified to consider our new revenue recognition policy effective January 1, 2018. As we implement the new standard, we have added internal controls to ensure that we adequately evaluate new contracts under the five-step model under ASU 2014-09.

Financial Condition and Liquidity

Summary.

Our financial condition and liquidity primarily depends on the cash flow from our operations and borrowings under our credit agreements. The principal factors determining our cash flow are:

•the amount of natural gas, oil, and NGLs we produce;
•the prices we receive for our natural gas, oil, and NGLs production;
•the demand for and the dayrates we receive for our drilling rigs; and
•the fees and margins we obtain from our natural gas gathering and processing contracts.

We believe we have sufficient cash flow and liquidity to meet our obligations and remain in compliance with our debt covenants for the next twelve months. Our ability to meet our debt covenants (under our credit agreements and our Indenture) and our capacity to incur additional indebtedness will depend on our future performance, which in turn will be affected by financial, business, economic, regulatory, and other factors. For example, lower oil, natural gas, and NGLs prices since the last redetermination under the Unit credit agreement could cause a redetermination of the borrowing base to a lower level and therefore reduce or limit our ability to borrow funds. We monitor our liquidity and capital resources, endeavor to anticipate potential covenant compliance issues and work with our lenders to address any of those issues ahead of time.

Below is a summary of certain financial information for the years ended December 31:

	2018	2017	2016
	(In thousands)		
Net cash provided by operating activities	$ 347,759	$ 265,956	$ 240,130
Net cash used in investing activities	(450,342)	(293,366)	(110,971)
Net cash provided by (used in) financing activities	108,334	27,218	(129,101)
Net increase (decrease) in cash and cash	$ 5,751	$ (192)	$ 58

equivalents

Cash Flows from Operating Activities

Our operating cash flow is primarily influenced by the prices we receive for our oil, NGLs, and natural gas production, the quantity of oil, NGL, and natural gas we produce, settlements of derivative contracts, third-party demand for our drilling rigs and mid-stream services, and the rates we can charge for those services. Our cash flows from operating activities are also affected by changes in working capital.

Net cash provided by operating activities increased by $81.8 million in 2018 compared to 2017 due primarily from higher revenues due to higher commodity prices and higher drilling rig utilization partially offset by changes in operating assets and liabilities related to the timing of cash receipts and disbursements.

Cash Flows from Investing Activities

We dedicate and expect to continue to dedicate a substantial portion of our capital budget to the exploration for and production of oil, NGLs, and natural gas. These expenditures are necessary to off-set the inherent production declines typically experienced in oil and gas wells.

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Cash flows used in investing activities increased by $157.0 million in 2018 compared to 2017. The change was due primarily to an increase in capital expenditures due to an increase in wells drilled, oil and gas property acquisitions, and the construction of new BOSS drilling rigs partially offset by an increase in the proceeds received from the disposition of assets. See additional information on capital expenditures below under Capital Requirements.

Cash Flows from Financing Activities

Cash flows provided by financing activities increased by $81.1 million in 2018 compared to 2017. The increase was primarily due to the proceeds from the sale of 50% interest in our mid-stream segment partially offset by the pay down of our outstanding debt under the Unit credit agreement.

At December 31, 2018, we had unrestricted cash totaling $6.5 million and had borrowed none of the amounts available under either of the Unit or Superior credit agreements.

Below is a summary of certain financial information as of December 31, and for the years ended December 31:

	2018		2017		2016	
	(In thousands)					
Working capital	$	(38,746)	$	(62,264)	$	(43,719)
Long-term debt (1)	$	644,475	$	820,276	$	800,917
Shareholders' equity attributable to Unit Corporation (2)	$	1,390,881	$	1,345,560	$	1,194,070
Net income (loss) attributable to Unit Corporation (2)	$	(45,288)	$	117,848	$	(135,624)

1.Long-term debt is net of unamortized discount and debt issuance costs.

2.In December 2018, we incurred a non-cash write-down associated with the removal of 41 drilling rigs from our fleet of $147.9 million pre-tax ($111.7 million, net of tax). In 2016, we incurred non-cash ceiling test write-downs of our oil and natural gas properties of $161.6 million pre-tax ($100.6 million, net of tax).

Working Capital

Typically, our working capital balance fluctuates, in part, because of the timing of our trade accounts receivable and accounts payable and the fluctuation in current assets and liabilities associated with the mark to market value of our derivative activity. We had negative working capital of $38.7 million, $62.3 million, and $43.7 million as of December 31, 2018, 2017, and 2016, respectively. The increase in working capital from 2017 is primarily due to increased cash and cash equivalents from the sale of 50% interest in our mid-stream segment and increased accounts receivable due to increased revenues, the change in the value of the derivatives outstanding and the fair value of drilling assets held for sale partially offset by increased accounts payable due to increased activity in our drilling program. The Unit and Superior credit agreements are used primarily for working capital and capital expenditures. At December 31, 2018, we had borrowed none of the $425.0 million available to us under the Unit credit agreement and none of the $200.0 million available to us under the Superior credit agreement. The effect of our derivatives increased working capital by $12.9 million as of December 31, 2018, decreased working capital by $7.1 million as of December 31, 2017, and increased working capital by $21.6 million as of December 31, 2016.

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This table summarizes certain operating information for the years ended December 31:

	2018			2017		2016	
Oil and Natural Gas:							
Oil production (MBbls)	2,874			2,715		2,974	
Natural gas liquids production (MBbls)	4,925			4,737		5,014	
Natural gas production (MMcf)	55,626			51,260		55,735	
Average oil price per barrel received	$	55.78		$	49.44	$	40.50
Average oil price per barrel received excluding derivatives	$	63.78		$	48.98	$	39.05
Average NGLs price per barrel received	$	22.18		$	18.35	$	11.26
Average NGLs price per barrel received excluding derivatives	$	22.58		$	18.35	$	11.26
Average natural gas price per mcf received	$	2.46		$	2.46	$	2.07
Average natural gas price per mcf received excluding derivatives	$	2.42		$	2.49	$	1.98
Contract Drilling:							
Average number of our drilling rigs in use during the period	32.8			30.0		17.4	
Total drilling rigs available for use at the end of the period	55			95		94	
Average dayrate	$	17,510		$	16,256	$	17,784
Mid-Stream:							
Gas gathered—Mcf/day	393,613			385,209		419,217	
Gas processed—Mcf/day	158,189			137,625		155,461	
Gas liquids sold—gallons/day	663,367			534,140		536,494	
Number of natural gas gathering systems	22		(1)	24		25	
Number of processing plants	14			13		13	

1.In 2018, our mid-stream segment transferred two natural gas gathering systems to our oil and natural gas segment.

Oil and Natural Gas Operations

Any significant change in oil, NGLs, or natural gas prices has a material effect on our revenues, cash flow, and the value of our oil, NGLs, and natural gas reserves. Generally, prices and demand for domestic natural gas are influenced by weather conditions, supply imbalances, and by worldwide oil price levels. Domestic oil prices are primarily influenced by world oil market developments. These factors are beyond our control and we cannot predict nor measure their future influence on the prices we will receive.

Based on our 2018 production, a $0.10 per Mcf change in what we are paid for our natural gas production, without the effect of derivatives, would cause a corresponding $439,000 per month ($5.3 million annualized) change in our pre-tax operating cash flow. Our 2018 average natural gas price was $2.46 compared to an average natural gas price of $2.46 for 2017 and $2.07 for 2016. A $1.00 per barrel change in our oil price, without the effect of derivatives, would have a $228,000 per month ($2.7 million annualized) change in our pre-tax operating cash flow and a $1.00 per barrel change in our NGLs prices, without the effect of derivatives, would have a $393,000 per month ($4.7 million annualized) change in our pre-tax operating cash flow based on our production in 2018. Our 2018 average oil price per barrel was $55.78 compared with an average oil price of $49.44 in 2017 and $40.50 in 2016, and our 2018 average NGLs price per barrel was $22.18 compared with an average NGLs price of $18.35 in 2017 and $11.26 in 2016.

Because commodity prices affect the value of our oil, NGLs, and natural gas reserves, declines in those prices can cause a decline in the carrying value of our oil and natural gas properties. At December 31, 2018, the 12-month average unescalated prices were $65.56 per barrel of oil, $37.68 per barrel of NGLs, and $3.10 per Mcf of natural gas, and then are adjusted for price differentials. We did not have to take a write down in 2018.

It is hard to predict with any reasonable certainty the need for or amount of any future impairments given the many factors that go into the ceiling test calculation including, but not limited to, future pricing, operating costs, drilling and completion costs, upward or downward oil and gas reserve revisions, oil and gas reserve additions, and tax attributes. Subject to these inherent uncertainties, if we hold these same factors constant as they existed at December 31, 2018 and only adjust the 12-month average price to an estimated first quarter ending average (holding February 2019 prices constant for the remaining one

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month of the first quarter of 2019), our forward-looking expectation is that we will not recognize an impairment in the first quarter of 2019. Commodity prices remain volatile and they could negatively affect the 12-month average price and the potential for an impairment in the first quarter.

Our natural gas production is sold to intrastate and interstate pipelines, to independent marketing firms and gatherers under contracts with terms generally ranging from one month to five years. Our oil production is sold to independent marketing firms generally under six-month contracts.

Contract Drilling Operations

Many factors influence the number of drilling rigs we have working and the costs and revenues associated with that work. These factors include the demand for drilling rigs in our areas of operation, competition from other drilling contractors, the prevailing prices for oil, NGLs, and natural gas, availability and cost of labor to run our drilling rigs, and our ability to supply the equipment needed.

Competition to keep qualified labor continues. We increased compensation for some rig personnel during the first quarter of 2018. Our drilling rig personnel are a key component to the overall success of our drilling services. With the present conditions in the drilling industry, we do not anticipate increases in the compensation paid to those personnel in the near term.

During 2018, almost all of our working drilling rigs were drilling horizontal or directional wells for oil and NGLs. The continuous fluctuations in commodity prices for oil and natural gas changes demand for drilling rigs. These factors ultimately affect the demand and mix of the type of drilling rigs used by our customers. The future demand for and the availability of drilling rigs to meet that demand will affect our future dayrates. For 2018, our average dayrate was $17,510 per day compared to $16,256 and $17,784 per day for 2017 and 2016, respectively. Our average number of drilling rigs used (utilization %) in 2018 was 32.8 (34%) compared with 30.0 (32%) and 17.4 (19%) in 2017 and 2016, respectively. Based on the average utilization of our drilling rigs during 2018, a $100 per day change in dayrates has a $3,280 per day ($1.2 million annualized) change in our pre-tax operating cash flow.

Our contract drilling segment provides drilling services for our exploration and production segment. Some of the drilling services we perform on our properties are, depending on the timing of those services, deemed associated with acquiring an ownership interest in the property. In those cases, revenues and expenses for those services are eliminated in our statement of operations, with any profit recognized as a reduction in our investment in our oil and natural gas properties. The contracts for these services are issued under the same conditions and rates as the contracts entered into with unrelated third parties. By providing drilling services for the oil and natural gas segment, we eliminated revenue of $22.5 million and $13.4 million during 2018 and 2017, respectively, from our contract drilling segment and eliminated the associated operating expense of $19.5 million and $11.8 million during 2018 and 2017, respectively, yielding $3.0 million and $1.6 million during 2018 and 2017, respectively, as a reduction to the carrying value of our oil and natural gas properties. We eliminated no revenue or expenses in our contract drilling segment during 2016.

Mid-Stream Operations

This segment is engaged primarily in the buying, selling, gathering, processing, and treating of natural gas. It operates three natural gas treatment plants, 14 processing plants, 22 gathering systems, and approximately 1,475 miles of pipeline. Its operations are in Oklahoma, Texas, Kansas, Pennsylvania, and West Virginia. This segment enhances our ability to gather and market not only our own natural gas and NGLs but also that owned by third parties and serves as a mechanism through which we can construct or acquire existing natural gas gathering and processing facilities. During 2018, 2017, and 2016 this segment purchased $81.4 million, $63.2 million, and $42.7 million, respectively, of our oil and natural gas segment's natural gas and NGLs production, and provided gathering and transportation services of $7.3 million, $6.7 million, and $9.2 million, respectively. Intercompany revenue from services and purchases of production between this business segment and our oil and natural gas segment has been eliminated in our consolidated financial statements.

Our mid-stream segment gathered an average of 393,613 Mcf per day in 2018 compared to 385,209 Mcf per day in 2017 and 419,217 Mcf per day in 2016. It processed an average of 158,189 Mcf per day in 2018 compared to 137,625 Mcf per day in 2017 and 155,461 Mcf per day in 2016, and sold NGLs of 663,367 gallons per day in 2018 compared to 534,140 gallons per day in 2017 and 536,494 gallons per day in 2016. Gas gathering volumes per day in 2018 increased primarily due to higher volumes at our Cashion and Hemphill facilities. Volumes processed increased primarily due to connecting new wells to our processing systems in 2018. NGLs sold increased primarily due to higher purchased volumes and better recoveries at our processing facilities.

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At-the-Market (ATM) Common Stock Program

On April 4, 2017, we entered into a Distribution Agreement (the Agreement) with a sales agent, under which we may offer and sell, from time to time, through the sales agent shares of our common stock, par value $0.20 per share (the Shares), up to an aggregate offering price of $100.0 million. We intended to use the net proceeds from these sales to fund (or offset costs of) acquisitions, future capital expenditures, repay amounts outstanding under our revolving credit facility, and general corporate purposes.

On May 2, 2018, we terminated the Distribution Agreement. The Distribution Agreement was terminable at will on written notification by us with no penalty. As of the date of termination, we had sold 787,547 shares of our common stock under the Distribution Agreement resulting in net proceeds of approximately$18.6 million. We paid the sales agent a commission of 2.0% of the gross sales price per share sold. As a result of the termination, there will be no more sales of our common stock under the Distribution Agreement.

Our Credit Agreements and Senior Subordinated Notes

Unit Credit Agreement. On October 18, 2018, we signed a Fifth Amendment to our Senior Credit Agreement (Unit credit agreement) amending our existing credit agreement entered into between the Company and certain lenders on September 13, 2011, as amended September 5, 2012, as further amended April 10, 2015, as further amended on April 8, 2016, as further amended on April 2, 2018, attached as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on September 15, 2011, September 11, 2012, April 13, 2015, April 8, 2016, and April 6, 2018, respectively, and the Company's Current Report on Form 8-K/A filed on April 13, 2016, and each incorporated by reference herein.

The Fifth Amendment, among other things, (i) extends the term of the Unit credit agreement to October 18, 2023, subject to certain conditions; (ii) reduces the pricing for borrowing and non-use fees; and (iii) eliminates the requirement that the company maintain a senior indebtedness to consolidated EBITDA ratio. The total commitment of credit and the borrowing base both remain unchanged at $425.0 million.

Under the Unit credit agreement, the amount we can borrow is the lesser of the amount we elect as the commitment amount or the value of the borrowing base as determined by the lenders, but in either event not to exceed the maximum credit agreement. We are charged a commitment fee of 0.375% on the amount available but not borrowed. That fee varies based on the amount borrowed as a percentage of the total borrowing base. Total amendment fees of $3.3 million in origination, agency, syndication, and other related fees are being amortized over the life of the Unit credit agreement. Under the Unit credit agreement, we have pledged as collateral 80% of the proved developed producing (discounted as present worth at 8%) total value of our oil and gas properties.

On April 2, 2018, we signed the fourth amendment to the Unit credit agreement. The Fourth Amendment provided, among other things, for a reduction of the maximum credit amount from $875.0 million to $425.0 million, a reduction in the borrowing base from $475.0 million to $425.0 million, a reduction in the total commitment amount from $475.0 million to $425.0 million; and the full release of Superior and its subsidiaries as a borrower and co-obligor under the Unit credit agreement. Under the amendment once the sale of the interest in Superior was completed, we were required to us part of the proceeds to pay down the Unit credit agreement. The Superior sale closed on April 3, 2018 and the pay down was made that day.

On May 2, 2018, as contemplated under the Fourth Amendment, we entered into a Pledge Agreement with BOKF, NA (dba Bank of Oklahoma), as administrative agent for the benefit of the secured parties, under which we granted a security interest in the limited liability membership interests and other equity interests we own in Superior (which as of the date of this report is 50% of the aggregate outstanding equity interests of Superior) as additional collateral for our obligations under the Unit credit agreement.

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The lenders under our Unit credit agreement and their respective participation interests are:

Lender	Participation Interest
BOK (BOKF, NA, dba Bank of Oklahoma)	17.060 %
BBVA Compass Bank	17.060 %
BMO Harris Financing, Inc.	15.294 %
Bank of America, N.A.	15.294 %
Comerica Bank	8.235 %
Toronto Dominion Bank, New York Branch	8.235 %
Canadian Imperial Bank of Commerce	8.235 %
Arvest Bank	3.529 %
Branch Banking & Trust	3.529 %
IBERIABANK	3.529 %
	100.000 %

The borrowing base amount–which is subject to redetermination by the lenders on April 1st and October 1st of each year–is based primarily on a percentage of the discounted future value of our oil and natural gas reserves. We or the lenders may request a one time special redetermination of the borrowing base between each scheduled redetermination. In addition, we may request a redetermination following the completion of an acquisition that meets the requirements in the Unit credit agreement.

At our election, any part of the outstanding debt under the Unit credit agreement may be fixed at a London Interbank Offered Rate (LIBOR). LIBOR interest is computed as the sum of the LIBOR base for the applicable term plus 1.50% to 2.50% depending on the level of debt as a percentage of the borrowing base and is payable at the end of each term, or every 90 days, whichever is less. Borrowings not under LIBOR bear interest at the prime rate specified in the Unit credit agreement that cannot be less than LIBOR plus 1.00% plus a margin. Interest is payable at the end of each month and the principal may be repaid in whole or in part at any time, without a premium or penalty. At December 31, 2018, we had no outstanding borrowings.

We can use borrowings for financing general working capital requirements for (a) exploration, development, production and acquisition of oil and gas properties, (b) acquisitions and operation of mid-stream assets, (c) issuance of standby letters of credit, (d) contract drilling services, and (e) general corporate purposes.

The Unit credit agreement prohibits, among other things:

- the payment of dividends (other than stock dividends) during any fiscal year over 30% of our consolidated net income for the preceding fiscal year;
- the incurrence of additional debt with certain limited exceptions;

•the creation or existence of mortgages or liens, other than those in the ordinary course of business, on any of our properties, except for our lenders; and
•investments in Unrestricted Subsidiaries (as defined in the Unit credit agreement) over $200.0 million.

The Unit credit agreement also requires that we have at the end of each quarter:

•a current ratio (as defined in the Unit credit agreement) of not less than 1 to 1.
•a leverage ratio of funded debt to consolidated EBITDA (as defined in the Unit credit agreement) for the most recently ended rolling four fiscal quarters of no greater than 4 to 1.

As of December 31, 2018, we were in compliance with the covenants in the Unit credit agreement.

Superior Credit Agreement. On May 10, 2018, Superior, a limited liability company equally owned between us and SP Investor Holdings, LLC, entered into a five-year, $200.0 million senior secured revolving credit facility with an option to increase the credit amount up to $250.0 million, subject to certain conditions. The amounts borrowed under the Superior credit agreement bear annual interest at a rate, at Superior’s option, equal to (a) LIBOR plus the applicable margin of 2.00% to 3.25% or (b) the alternate base rate (greater of (i) the federal funds rate plus 0.5%, (ii) the prime rate, and (iii) third day LIBOR plus

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1.00%) plus the applicable margin of 1.00% to 2.25%. The obligations under the Superior credit agreement are secured by, among other things, mortgage liens on certain of Superior’s processing plants and gathering systems.

Superior is charged a commitment fee of 0.375% on the amount available but not borrowed which varies based on the amount borrowed as a percentage of the total borrowing base. Superior paid $1.7 million in origination, agency, syndication, and other related fees. These fees are being amortized over the life of the Superior credit agreement.

The Superior credit agreement requires that Superior maintain a Consolidated EBITDA to interest expense ratio for the most-recently ended rolling four quarters of at least 2.50 to 1.00, and a funded debt to Consolidated EBITDA ratio of not greater than 4.00 to 1.00. Additionally, the Superior credit agreement contains a number of customary covenants that, among other things, restrict (subject to certain exceptions) Superior’s ability to incur additional indebtedness, create additional liens on its assets, make investments, pay distributions, enter into sale and leaseback transactions, engage in certain transactions with affiliates, engage in mergers or consolidations, enter into hedging arrangements, and acquire or dispose of assets. As of December 31, 2018, Superior was in compliance with the Superior credit agreement covenants.

The borrowings the Superior credit agreement will be used to fund capital expenditures and acquisitions, provide general working capital, and for letters of credit for Superior.

On June 27, 2018, Superior and the lenders amended the Superior credit agreement to revise certain definitions in the agreement.

Superior's credit agreement is not guaranteed by Unit.

The current lenders under the Superior credit agreement and their respective participation interests are:

Lender	Participation Interest
BOK (BOKF, NA, dba Bank of Oklahoma)	17.50%
Compass Bank	17.50%
BMO Harris Financing, Inc.	13.75%
Toronto Dominion (New York), LLC	13.75%
Bank of America, N.A.	10.00%
Branch Banking and Trust Company	10.00%
Comerica Bank	10.00%
Canadian Imperial Bank	7.50%

of Commerce

100.00%

6.625% Senior Subordinated Notes. We have an aggregate principal amount of $650.0 million, 6.625% senior subordinated notes (the Notes). Interest on the Notes is payable semi-annually (in arrears) on May 15 and November 15 of each year. The Notes will mature on May 15, 2021. In issuing the Notes, we incurred $14.7 million of fees that are being amortized as debt issuance cost over the life of the Notes.

The Notes are subject to an Indenture dated as of May 18, 2011, between us and Wilmington Trust, National Association (successor to Wilmington Trust FSB), as Trustee (the Trustee), as supplemented by the First Supplemental Indenture dated as of May 18, 2011, between us, the Guarantors, and the Trustee, and as further supplemented by the Second Supplemental Indenture dated as of January 7, 2013, between us, the Guarantors and the Trustee (as supplemented, the 2011 Indenture), establishing the terms and providing for issuing the Notes. The Guarantors are our direct and indirect subsidiaries. The discussion of the Notes in this report is qualified by and subject to the actual terms of the 2011 Indenture.

Unit, as the parent company, has no independent assets or operations. The guarantees by the Guarantors of the Notes (registered under registration statements) are full and unconditional, joint and several, subject to certain automatic customary releases, are subject to certain restrictions on the sale, disposition, or transfer of the capital stock or substantially all of the assets of a subsidiary guarantor, and other conditions and terms set out in the Indenture. Any of our subsidiaries that are not Guarantors are minor. There are no significant restrictions on our ability to receive funds from our subsidiaries through dividends, loans, advances or otherwise.

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We may redeem all or, from time to time, a part of the Notes at certain redemption prices, plus accrued and unpaid interest. If a “change of control” occurs, subject to certain conditions, we must offer to repurchase from each holder all or any part of that holder’s Notes at a purchase price in cash equal to 101% of the principal amount of the Notes plus accrued and unpaid interest, if any, to the date of purchase. The 2011 Indenture contains customary events of default. The 2011 Indenture also contains covenants that, among other things, limit our ability and the ability of certain of our subsidiaries to incur or guarantee additional indebtedness; pay dividends on our capital stock or redeem capital stock or subordinated indebtedness; transfer or sell assets; make investments; incur liens; enter into transactions with our affiliates; and merge or consolidate with other companies. We were in compliance with all covenants of the Notes as of December 31, 2018.

Capital Requirements

Oil and Natural Gas Dispositions, Acquisitions, and Capital Expenditures. Most of our capital expenditures for this segment are discretionary and directed toward growth. Any decision to increase our oil, NGLs, and natural gas reserves through acquisitions or through drilling depends on the prevailing or expected market conditions, potential return on investment, future drilling potential, and opportunities to obtain financing, which provide us flexibility in deciding when and if to incur these costs. We completed drilling 117 gross wells (33.16 net wells) in 2018 compared to 70 gross wells (25.71 net wells) in 2017, and 21 gross wells (9.67 net wells) in 2016.

On April 3, 2017, we closed an acquisition of certain oil and natural gas assets located primarily in Grady and Caddo Counties in western Oklahoma. The final adjusted value of consideration given was $54.3 million. As of January 1, 2017, the effective date of the acquisition, the estimated proved oil and gas reserves of the acquired properties were 3.2 million barrels of oil equivalent (MMBoe). The acquisition added approximately 8,300 net oil and gas leasehold acres to our core Hoxbar area in southwestern Oklahoma including approximately 47 proved developed producing wells. This acquisition included 13 potential horizontal drilling locations not otherwise included in our existing acreage. Of the acreage acquired, approximately 71% was held by production. We also received one gathering system as part of the transaction.

In December 2018, we closed on an acquisition of certain oil and natural gas assets located primarily in Custer County, Oklahoma. The total preliminary adjusted value of consideration given was $29.6 million. As of November 1, 2018, the effective date of the acquisition, the estimated proved oil and gas reserves for the acquired properties was 2.6 MMBoe net to Unit. The acquisition added approximately 8,667 net oil and gas leasehold acres to our Penn Sands area in Oklahoma including approximately 44 wells. The acquisitions included approximately 30 potential horizontal drilling locations which are anticipated to have a high percentage of oil relative to the total production stream. Of the acreage acquired, approximately 82% was held by production.

Capital expenditures for oil and gas properties on the full cost method for 2018 by this segment, excluding a $7.6 million reduction in the ARO liability and $30.7 million in acquisitions (including associated ARO), totaled $344.3 million compared to 2017 capital expenditures of $215.4 million (excluding a $4.0 million reduction in the ARO liability and $59.0 million in acquisitions), and 2016 capital expenditures of $119.9 million (excluding an $30.9 million reduction in the ARO liability and $0.6 million in acquisitions).

For 2019, we plan to participate in drilling approximately 90 to 100 gross wells and estimate our total capital expenditures (excluding any possible acquisitions) for our oil and natural gas segment will range from approximately $271.0 million to $315.0 million. Whether we drill all of those wells depends on several factors, many of which are beyond our control and include the availability of drilling rigs, availability of pressure pumping services, prices for oil, NGLs, and natural gas, demand for oil, NGLs, and natural gas, the cost to drill wells, the weather, and the efforts of outside industry partners.

We sold non-core oil and natural gas assets, net of related expenses, for $22.5 million, $18.6 million, and $67.2 million during 2018, 2017, and 2016, respectively. Proceeds from those dispositions reduced the net book value of our full cost pool with no gain or loss recognized.

Contract Drilling Dispositions, Acquisitions, and Capital Expenditures. During December 2016, we sold an idle 1500 HP SCR drilling rig to an unaffiliated third party. We also fabricated and placed into service our ninth new BOSS drilling rig for a third party operator. This new BOSS rig was constructed using the long lead time components purchased in prior years.

During 2017, we built our tenth BOSS drilling rig and placed it into service for a third party operator under a long term contract. We also returned to service 14 SCR drilling rigs that had been previously stacked.

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During 2018, we built our 11th BOSS drilling and placed it into service for a third party operator under a long term contract. We also made modifications to nine SCR rigs to meet customer requirements.

In December 2018, our Board of Directors approved a plan to sell 41 drilling rigs (29 mechanical drilling rigs and 12 SCR diesel-electric drilling rigs) and other equipment. This plan satisfies the criteria of assets held for sale under ASC 360-10-45-9. Over the last five years, only six of our drilling rigs in the fleet have not been utilized. We made a strategic decision to focus on our new BOSS drilling rigs and specific SCR drilling rigs (good candidates for modification) and sell the other drilling rigs that we now choose not to market. We estimated the fair value of the 41 drilling rigs we will no longer market based on the estimated market value from third-party assessments (Level 3 fair value measurement) less cost to sell. Based on these estimates, we recorded a non-cash write-down of approximately $147.9 million, pre-tax ($111.7 million, net of tax).

Our anticipated 2019 capital expenditures for this segment range from approximately $30.0 million to $65.0 million. We spent $75.5 million for capital expenditures during 2018 compared to $36.1 million in 2017, and $19.1 million in 2016.

Mid-Stream Dispositions, Acquisitions, and Capital Expenditures. In the Appalachian region at the Pittsburgh Mills gathering system, average gathered volume for the fourth quarter of 2018 was approximately 129.7 MMcf per day and the annual average gathered volume was 123.9 MMcf per day. In 2018, we added seven new infill wells late in the second quarter and all the new infill wells are currently online and flowing gas. We have completed construction of the new pipeline to connect the next scheduled well pad to our system. We have also completed the upgrade of the compressor station and dehydration facilities. Production from this new pad started online during January 2019.

At the Hemphill Texas system, average total throughput volume for the fourth quarter of 2018 increased to 75.3 MMcf per day and total production of natural gas liquids was approximately 301,500 gallons per day during this same period. The annual average throughput volume was 72.6 MMcf per day while the annual total production of natural gas liquids averaged 264,971 gallons per day. During the fourth quarter, we connected five new wells in the Buffalo Wallow area. These new wells along with increased production from recently drilled wells in this area contributed to the increased throughput volume. Our oil and gas segment continues to operate a rig in the Buffalo Wallow area and we anticipate connecting additional wells to this system in 2019.

At the Cashion processing facility in central Oklahoma, total throughput volume for the fourth quarter of 2018 averaged approximately 49.2 MMcf per day and total production of natural gas liquids increased to 246,873 gallons per day. The annual average throughput volume was 46.0 MMcf per day and the annual average natural gas liquids production was 234,316 gallons per day. This system is currently operating at full processing capacity and we are adding additional capacity to this system. We are relocating a 60 MMcf per day processing plant from our Bellmon facility to the Cashion area. This processing plant will be installed at the Reeding site on the Cashion system. This plant is expected to be operational by the end of the first quarter of 2019 and it will increase our total processing capacity on the Cashion system to approximately 105 MMcf per day. We connected eight new wells to this system during the fourth quarter of 2018 and we are continuing to connect additional wells from a third party producer who continues to be active in this area.

At the Minco processing facility in central Oklahoma, total throughput volume for the fourth quarter of 2018 was approximately 8.0 MMcf per day and the average annual total throughput volume was 9.5 MMcf per day. During the fourth quarter of 2018 we completed a new interconnect with a producer who is currently delivering gas to our system. Additionally, we are completing construction of a new well connect for a third party producer who is expected to deliver gas to our system in 2019. The current processing capacity of the Minco facility is approximately 12 MMcf per day.

During 2018, our mid-stream segment incurred $44.8 million in capital expenditures as compared to $22.2 million in 2017, and $16.8 million, in 2016. For 2019, our estimated capital expenditures range from approximately $35.0 million to $42.0 million.

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Contractual Commitments

At December 31, 2018, we had these contractual obligations:

	Payments Due by Period				
	Total	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
	(In thousands)				
Long-term debt (1)	$ 752,052	$ 43,063	$ 708,989	$ —	$ —
Operating leases (2)	6,702	4,550	2,152	—	—
Capital lease interest and maintenance (3)	4,724	2,168	2,556	—	—
Drill pipe, drilling components, and equipment purchases (4)	9,215	9,215	—	—	—
Total contractual obligations	$ 772,693	$ 58,996	$ 713,697	$ —	$ —

1.See previous discussion in MD&A regarding our long-term debt. This obligation is presented under the Notes and the Unit and Superior credit agreements and includes interest calculated using our December 31, 2018 interest rates of 6.625% for the Notes. The outstanding Unit credit facility balance was paid down on April 3, 2018, and as of December 31, 2018, we did not have any outstanding borrowings.
2.We lease office space or yards in Edmond and Oklahoma City, Oklahoma; Houston, Texas; Englewood, Colorado; Pinedale, Wyoming; and Canonsburg, Pennsylvania under the terms of operating leases expiring through December 2021. And, we have several equipment leases and lease space on short-term commitments to stack excess drilling rig equipment and production inventory.
3.Maintenance and interest payments are included in our capital lease agreements. The capital leases are discounted using annual rates of 4.0%. Total maintenance and interest remaining are $4.1 million and $0.6 million, respectively.
4.We have committed to purchase approximately $9.2 million of new drilling rig components over the next year.

During the second quarter of 2018, we entered into a contractual obligation that commits us to spend $150.0 million for drilling wells in the Granite Wash/Buffalo Wallow area over the next three years starting January 1, 2019. This amount is already included in our drilling plan. For each dollar of the $150.0 million that we do not spend (over the three year period), we would forgo receiving $0.58 of future distributions from our 50% ownership interest in our consolidated mid-stream subsidiary. If we elected not to drill or spend any money in the designated area over the three year period, the maximum amount we could forgo from distributions would be $87.0 million.

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At December 31, 2018, we also had these commitments and contingencies that could create, increase or accelerate our liabilities:

Other Commitments	Estimated Amount of Commitment Expiration Per Period								
	Total Accrued		Less Than 1 Year		2-3 Years		4-5 Years		After 5 Years
	(In thousands)								
Deferred compensation plan (1)	$	5,132	Unknown		Unknown		Unknown		Unknown
Separation benefit plans (2)	$	8,814	$	812	Unknown		Unknown		Unknown
ARO liability (3)	$	64,208	$	1,437	$	36,033	$	3,570	$ 23,168
Gas balancing liability (4)	$	3,331	Unknown		Unknown		Unknown		Unknown
Repurchase obligations (5)	$	—	Unknown		Unknown		Unknown		Unknown
Workers' compensation liability (6)	$	12,738	$	5,126	$	2,478	$	1,000	$ 4,134
Capital lease obligations (7)	$	11,380	$	4,001	$	7,379	$	—	$ —
Contract liability (8)	$	9,881	$	2,874	$	5,460	$	1,547	$ —
Derivative liabilities—commodity hedges	$	293	$	—	$	293	$	—	$ —

1.We provide a salary deferral plan which allows participants to defer the recognition of salary for income tax purposes until actual distribution of benefits, which occurs at either termination of employment, death or certain defined unforeseeable emergency hardships. We recognize payroll expense and record a liability, included in other long-term liabilities in our Consolidated Balance Sheets, at the time of deferral.

2.Effective January 1, 1997, we adopted a separation benefit plan (Separation Plan). The Separation Plan allows eligible employees whose employment with us is involuntarily terminated or with an employee who has completed 20 years of service, voluntarily or involuntarily terminated, to receive benefits equivalent to four weeks salary for every whole year of service completed with the company up to a maximum of 104 weeks. To receive payments the recipient must waive certain claims against us in exchange for receiving the separation benefits. On October 28, 1997, we adopted a Separation Benefit Plan for Senior Management (Senior Plan). The Senior Plan provides certain officers and key executives of the company with benefits generally equivalent to the Separation Plan. The Compensation Committee of the Board of Directors has absolute discretion in the selection of the individuals covered in this plan. On May 5, 2004 we also adopted the Special Separation Benefit Plan (Special Plan). This plan is identical to the Separation Benefit Plan with the exception that the benefits under the plan vest on the earliest of a participant's reaching the age of 65 or serving 20 years with the company.

3.When a well is drilled or acquired, under ASC 410 "Accounting for Asset Retirement Obligations," we record the fair value of liabilities associated with the retirement of long-lived assets (mainly plugging and abandonment costs for our depleted wells).

4.We have recorded a liability for those properties we believe do not have sufficient oil, NGLs, and natural gas reserves to allow the under-produced owners to recover their under-production from future production volumes.

5.We formed The Unit 1984 Oil and Gas Limited Partnership and the 1986 Energy Income Limited Partnership along with private limited partnerships (the Partnerships) with certain qualified employees, officers and directors from 1984 through 2011. One of our subsidiaries serves as the general partner of each of these programs. Effective December 31, 2014, the 1984 partnership was dissolved and effective December 31, 2016, the two 1986 partnerships were also dissolved. The Partnerships were formed to conduct oil and natural gas acquisition, drilling and development operations and serving as co-general partner with us in any additional limited partnerships formed during that year. The Partnerships participated on a proportionate basis with us in most drilling operations and most producing property acquisitions commenced by us for our own account during the period from the formation of the Partnership through December 31 of that year. These partnership agreements require, on the election of a limited partner, that we repurchase the limited partner's interest at amounts to be determined by appraisal in the future. Repurchases in any one year are limited to 20% of the units outstanding. We made repurchases of approximately $1,700, $2,900, and $5,000 in 2018, 2017, and 2016, respectively. Effective January 1, 2019, we elected to terminate and wind down all of the remaining employee limited partnerships. In accordance with the partnership agreements, we, as the liquidating trustees will value the interests of the limited partners using the formula provided in each partnership agreement and purchase those interests. Presently, we expect the total purchase price for all of the limited partners interests will be approximately $0.6 million. We have no plans to sponsor additional employee limited partnerships.

6.We have recorded a liability for future estimated payments related to workers' compensation claims primarily associated with our contract drilling segment.

7.This amount includes commitments under capital lease arrangements for compressors in our mid-stream segment.

8.We have recorded a liability related to the timing of the revenue recognized on certain demand fees for Superior.

Derivative Activities

Periodically we enter into derivative transactions locking in the prices to be received for a portion of our oil, NGLs, and natural gas production. Any change in the fair value of all our derivatives are reflected in the statement of operations.

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Commodity Derivatives. Our commodity derivatives should reduce our exposure to price volatility and manage price risks. Our decision on the type and quantity of our production and the price(s) of our derivative(s) is based, in part, on our view of current and future market conditions. As of December 31, 2018, based on our fourth quarter 2018 average daily production, the approximated percentages of our production under derivative contracts are as follows:

	Mark-to-Market			
	2019			
	Q1	**Q2**	**Q3**	**Q4**
Daily oil production	51%	51%	51%	51%
Daily natural gas production	66%	52%	52%	44%

Regarding the commodities subject to derivative contracts, those contracts limit the risk of adverse downward price movements. However, they also limit increases in future revenues that would otherwise result from price movements above the contracted prices.

Using derivative transactions has the risk that the counterparties may not meet their financial obligations under the transactions. Based on our evaluation at December 31, 2018, we believe the risk of non-performance by our counterparties is not material. At December 31, 2018, the fair values of the net assets we had with each of the counterparties to our commodity derivative transactions are:

	December 31, 2018	
	(In millions)	
Bank of Montreal	$	9.9
Bank of America Merrill Lynch	2.7	
Total net assets	$	12.6

If a legal right of set-off exists, we net the value of the derivative arrangements we have with the same counterparty in our Consolidated Balance Sheets. At December 31, 2018, we recorded the fair value of our commodity derivatives on our balance sheet as current derivative assets of $12.9 million and long-term derivative liabilities of $0.3 million. At December 31, 2017, we recorded the fair value of our commodity derivatives on our balance sheet as current derivative assets of $0.7 million and current derivative liabilities of $7.8 million.

All derivatives are recognized on the balance sheet and measured at fair value. Any changes in our derivatives' fair value before their maturity (i.e., temporary fluctuations in value) are reported in gain (loss) on derivatives in our Consolidated Statements of Operations.

These gains (losses) are as follows at December 31:

	2018		**2017**		**2016**	
	(In thousands)					
Gain (loss) on derivatives, included are	$	(3,184)	$	14,732	$	(22,813)

amounts settled during the period of ($22,803), $173, and $9,658, respectively

Stock and Incentive Compensation

During 2018, we granted awards covering 1,279,255 shares of restricted stock. These awards were granted as retention incentive awards. These stock awards had an estimated fair value as of the grant date of $24.7 million. Compensation expense will be recognized over the awards' three year vesting period. During 2018, we recognized $9.4 million in additional compensation expense and capitalized $1.4 million for these awards. During 2017, we granted awards covering 708,276 shares of restricted stock. These awards were granted as retention incentive awards and are being recognized over the awards' three year vesting period. During 2016, we granted awards covering 736,451 shares of restricted stock. These awards were granted as retention incentive awards and are being recognized over their two and three year vesting periods. No SAR awards were made during 2018, 2017, or 2016.

During 2018, we recognized compensation expense of $17.8 million for our restricted stock grants and capitalized $2.1 million of compensation cost for oil and natural gas properties.

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Insurance

We are self-insured for certain losses relating to workers' compensation, general liability, control of well, and employee medical benefits. Insured policies for other coverage contain deductibles or retentions per occurrence that range from zero to $1.0 million. We have purchased stop-loss coverage to limit, to the extent feasible, per occurrence and aggregate exposure to certain types of claims. There is no assurance that the insurance coverage we have will protect us against liability from all potential consequences. If insurance coverage becomes more expensive, we may choose to self-insure, decrease our limits, raise our deductibles, or any combination of these rather than pay higher premiums.

Oil and Natural Gas Limited Partnerships and Other Entity Relationships.

We are the general partner of 13 oil and natural gas partnerships formed privately or publicly. Each partnership's revenues and costs are shared under formulas set out in that partnership's agreement. The partnerships repay us for contract drilling, well supervision and general and administrative expense. Related party transactions for contract drilling and well supervision fees are the related party's share of such costs. These costs are billed the same as billings to unrelated third parties for similar services. General and administrative reimbursements consist of direct general and administrative expense incurred on the related party's behalf and indirect expenses assigned to the related parties. Allocations are based on the related party's level of activity and are considered by us to be reasonable. During 2018, 2017, and 2016, the total we received for these fees was $0.2 million, $0.2 million, and $0.3 million, respectively. Our proportionate share of assets, liabilities, and net income relating to the oil and natural gas partnerships is included in our consolidated financial statements. These partnerships will be terminated in 2019.

Effects of Inflation

The effect of inflation in the oil and natural gas industry is primarily driven by the prices for oil, NGLs, and natural gas. Increases in these prices increase the demand for our contract drilling rigs and services. This increase in demand affects the dayrates we can obtain for our contract drilling services. During periods of higher demand for our drilling rigs we have experienced increases in labor costs and the costs of services to support our drilling rigs. Historically, during this same period, when oil, NGLs, and natural gas prices declined, labor rates did not come back down to the levels existing before the increases. If commodity prices increase substantially for a long period, shortages in support equipment (like drill pipe, third party services, and qualified labor) can cause additional increases in our material and labor costs. Increases in dayrates for drilling rigs also increase the cost of our oil and natural gas properties. Commodity prices also can affect our fracking and completion costs. How inflation will affect us in the future will depend on increases, if any, realized in our drilling rig rates, the prices we receive for our oil, NGLs, and natural gas, and the rates we receive for gathering and processing natural gas. Due to increased demand for drilling rigs and the need to maintain qualified labor, we increased pay for some of our drilling personnel in the first quarter of 2018.

Off-Balance Sheet Arrangements

We do not currently utilize any off-balance sheet arrangements with unconsolidated entities to enhance liquidity and capital resource positions, or for any other purpose. However, as is customary in the oil and gas industry, we are subject to various contractual commitments.

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Results of Operations

2018 versus 2017

	2018	2017	Percent Change (1)
	(In thousands unless otherwise specified)		
Total revenue	$ 843,281	$ 739,640	14 %
Net income (loss)	$ (39,767)	$ 117,848	(134)%
Net income attributable to non-controlling interest	$ 5,521	$ —	— %
Net income (loss) attributable to Unit Corporation	$ (45,288)	$ 117,848	(138)%
Oil and Natural Gas:			
Revenue	$ 423,059	$ 357,744	18 %
Operating costs excluding depreciation, depletion, amortization, and impairment	$ 131,675	$ 130,789	1 %
Depreciation, depletion, and amortization	$ 133,584	$ 101,911	31 %
Average oil price received (Bbl)	$ 55.78	$ 49.44	13 %
Average NGL price received (Bbl)	$ 22.18	$ 18.35	21 %
Average natural gas price received (Mcf)	$ 2.46	$ 2.46	— %
Oil production (MBbls)	2,874	2,715	6 %
NGLs production (MBbls)	4,925	4,737	4 %
Natural gas production (MMcf)	55,626	51,260	9 %
Depreciation, depletion, and amortization rate (Boe)	$ 7.50	$ 6.00	25 %
Contract Drilling:			
Revenue	$ 196,492	$ 174,720	12 %
Operating costs excluding depreciation	$ 131,385	$ 122,600	7 %
Depreciation	$ 57,508	$ 56,370	2 %
Impairment of contract drilling	$ 147,884	$ —	— %

equipment			
Percentage of revenue from daywork contracts	100%	100 %	—%
Average number of drilling rigs in use	32.8	30.0	9 %
Average dayrate on daywork contracts	$ 17,510	$ 16,256	8 %
Mid-Stream:			
Revenue	$ 223,730	$ 207,176	8 %
Operating costs excluding depreciation and amortization	$ 167,836	$ 155,483	8 %
Depreciation and amortization	$ 44,834	$ 43,499	3 %
Gas gathered—Mcf/day	393,613	385,209	2 %
Gas processed—Mcf/day	158,189	137,625	15 %
Gas liquids sold—gallons/day	663,367	534,140	24 %
Corporate and other:			
General and administrative expense	$ 38,707	$ 38,087	2 %
Other depreciation	$ 7,679	$ 7,477	3 %
Gain on disposition of assets	$ 704	$ 327	115 %
Other income (expense):			
Interest income	$ 972	$ —	—%
Interest expense, net	$ (34,466)	$ (38,334)	(10)%
Gain (loss) on derivatives	$ (3,184)	$ 14,732	(122)%
Other	$ 22	$ 21	5 %
Income tax benefit	$ (13,996)	$ (57,678)	76 %
Average interest rate	6.5 %	6.0 %	8 %
Average long-term debt outstanding	$ 685,330	$ 810,734	(15)%

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Oil and Natural Gas

Oil and natural gas revenues increased $65.3 million or 18% in 2018 as compared to 2017 due primarily to higher oil and NGLs prices and higher production. Oil production increased 6%, NGLs production increased 4%, and natural gas production increased 9%. Average oil prices between the comparative years increased 13% to $55.78 per barrel, NGLs prices increased 21% to $22.18 per barrel, and natural gas prices remained at $2.46 per Mcf.

Oil and natural gas operating costs increased $0.9 million or 1% between the comparative years of 2018 and 2017 primarily due to higher LOE, gross production taxes, general and administrative expenses, and saltwater disposal expense, partially offset by less expenses due to certain deductions being netted in revenues after ASC 606 implementation in 2018.

DD&A increased $31.7 million or 31% primarily due to a 25% increase in our DD&A rate and by the effect of a 7% increase in equivalent production. The increase in our DD&A rate in 2018 compared to 2017 resulted primarily from the cost of wells drilled in 2018.

Contract Drilling

Drilling revenues increased $21.8 million or 12% in 2018 as compared to 2017. The increase was due primarily to a 9% increase in the average number of drilling rigs in use and an 8% increase in the average dayrate compared to 2017. Average drilling rig utilization increased from 30.0 drilling rigs in 2017 to 32.8 drilling rigs in 2018.

Drilling operating costs increased $8.8 million or 7% in 2018 compared to 2017. The increase was due primarily to more drilling rigs operating and to a less extent from increased per day direct cost. Contract drilling depreciation increased $1.1 million or 2% also due primarily to more drilling rigs operating and the acceleration of depreciation on drilling rigs stacked for more than 48 months.

In December 2018, our Board of Directors approved a plan to sell 41 drilling rigs (29 mechanical drilling rigs and 12 SCR diesel-electric drilling rigs) and other equipment. This plan satisfies the criteria of assets held for sale under ASC 360-10-45-9. Over the last five years, only six of our drilling rigs in the fleet have not been utilized. We made a strategic decision to focus on our new BOSS drilling rigs and specific SCR drilling rigs (good candidates for modification) and sell the other drilling rigs that we now choose not to market. We estimated the fair value of the 41 drilling rigs we will no longer market based on the estimated market value from third-party assessments (Level 3 fair value measurement) less cost to sell. Based on these estimates, we recorded a non-cash write-down of approximately $147.9 million, pre-tax ($111.7 million, net of tax).

Mid-Stream

Our mid-stream revenues increased $16.6 million or 8% in 2018 as compared to 2017 primarily due to increased NGLs and condensate sales partially offset by lower gas sales, transportation revenue, and increased intercompany eliminations. Gas processing volumes per day increased 15% between the comparative years primarily due to connecting new wells to our processing systems. Gas gathering volumes per day increased 2% primarily due to connecting new wells at several of our gathering and processing systems.

Operating costs increased $12.4 million or 8% in 2018 compared to 2017 primarily due to an increase in purchased volume along with an increase in purchase prices combined with increased mid-stream direct G&A and field direct expenses partially offset by increased intercompany eliminations. Depreciation and amortization increased $1.3 million or 3% primarily due to placing additional capital assets into service in 2018.

General and Administrative

General and administrative expenses increased $0.6 million or 2% in 2018 compared to 2017 primarily due to higher employee costs.

Other Depreciation

Other depreciation increased $0.2 million in 2018 compared to 2017 primarily due to the depreciation on the new ERP system.

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Gain on Disposition of Assets

Gain on disposition of assets increased $0.4 million in 2018 compared to 2017. The gain in 2018 was primarily for the sale of drilling equipment and vehicles, while gain in 2017 was primarily for the sale of a corporate aircraft and vehicles.

Other Income (Expense)

Interest expense, net of capitalized interest, decreased $3.9 million between the comparative years of 2018 and 2017. We capitalized interest based on the net book value associated with unproved properties not being amortized, the construction of additional drilling rigs, and the construction of gas gathering systems. Capitalized interest for 2018 was $16.5 million compared to $15.9 million in 2017, and was netted against our gross interest of $51.0 million and $54.2 million for 2018 and 2017, respectively. Our average interest rate increased from 6.0% to 6.5% and our average debt outstanding was $125.4 million lower in 2018 as compared to 2017 primarily due to the pay down of our Unit credit agreement in the second quarter of 2018. We had interest earned of $1.0 million from the excess cash in our investment accounts from the sale of 50% of Superior.

Gain (loss) on derivatives decreased from a gain of $14.7 million in 2017 to a loss of $3.2 million in 2018 primarily due to fluctuations in forward prices used to estimate the fair value in mark-to-market accounting.

Income Tax Benefit

Income tax benefit decreased $43.7 million in 2018 compared to 2017. We recognized an income tax benefit of $14.0 million in 2018 compared to an income tax benefit of $57.7 million in 2017. The 2017 benefit was due to the revaluation of our net deferred tax liability in connection with the enactment of the Tax Cuts and Jobs Act (the Tax Act) in December 2017 which resulted in an $81.3 million reduction in our deferred liability. Taxable income before the impairment was higher in 2018 resulting in higher tax netted against the $111.7 tax benefit from the impairment.

Our effective tax rate was 26.0% for 2018 compared to 95.9% for 2017. The effective tax rate for the current year was more normalized as compared to 2017 because of the negative rate resulting from enactment of the Tax Act and revaluation of our net deferred tax liability during 2017. We paid $3.6 million in state income taxes during 2018 due to the sale of 50% interest in our mid-stream segment.

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2017 versus 2016

	2017	2016	Percent Change (1)
	(In thousands unless otherwise specified)		
Total revenue	$ 739,640	$ 602,177	23 %
Net income (loss)	$ 117,848	$ (135,624)	187 %
Oil and Natural Gas:			
Revenue	$ 357,744	$ 294,221	22 %
Operating costs excluding depreciation, depletion, amortization, and impairment	$ 130,789	$ 120,184	9 %
Depreciation, depletion, and amortization	$ 101,911	$ 113,811	(10)%
Impairment of oil and natural gas properties	$ —	$ 161,563	(100)%
Average oil price received (Bbl)	$ 49.44	$ 40.50	22 %
Average NGLs price received (Bbl)	$ 18.35	$ 11.26	63 %
Average natural gas price received (Mcf)	$ 2.46	$ 2.07	19 %
Oil production (MBbls)	2,715	2,974	(9)%
NGLs production (MBbls)	4,737	5,014	(6)%