CNX Resources Corp
Form 10-K
February 07, 2019

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

FORM 10-K

(Mark One)

x **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

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

For the transition period from __________ to __________
Commission file number: 001-14901

CNX Resources Corporation
(Exact name of registrant as specified in its charter)

Delaware	**51-0337383**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

CNX Center
1000 CONSOL Energy Drive Suite 400
Canonsburg, PA 15317-6506
(724) 485-4000
(Address, including zip code, and telephone number, including area code, of registrant's principal executive offices)

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

Title of each class	**Name of exchange on which registered**
Common Stock ($.01 par value)	New York Stock Exchange
Preferred Share Purchase Rights	New York Stock Exchange

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 o
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o 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 o
Indicate by check mark whether the registrant has submitted electronically, if any, 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 o
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405) 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. o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company, " and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):
Large accelerated filer x Accelerated filer o Non-accelerated filer o Smaller Reporting Company o Emerging Growth Company o

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. o

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

The aggregate market value of voting stock held by nonaffiliates of the registrant as of June 30, 2018, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price of the common stock on the New York Stock Exchange on such date was $1,652,490,069.

The number of shares outstanding of the registrant's common stock as of January 18, 2019 is 198,335,252 shares.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of CNX's Proxy Statement for the Annual Meeting of Shareholders to be held on May 29, 2019, are incorporated by reference in Items 10, 11, 12, 13 and 14 of Part III.

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GLOSSARY OF CERTAIN OIL AND GAS TERMS

The following are certain terms and abbreviations commonly used in the oil and gas industry and included within this Form 10-K:

Bbl - One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.
Bcf - One billion cubic feet of natural gas.
Bcfe - One billion cubic feet of natural gas equivalents, with one barrel of oil being equivalent to 6,000 cubic feet of gas.
Btu - One British Thermal unit.
BBtu - billion British Thermal units.
Mbbls - One thousand barrels of oil or other liquid hydrocarbons.
Mcf - One thousand cubic feet of natural gas.
Mcfe - One thousand cubic feet of natural gas equivalents, with one barrel of oil being equivalent to 6,000 cubic feet of gas.
MMbtu - One million British Thermal units.
MMcfe - One million cubic feet of natural gas equivalents, with one barrel of oil being equivalent to 6,000 cubic feet of gas.
Tcfe - One trillion cubic feet of natural gas equivalents, with one barrel of oil being equivalent to 6,000 cubic feet of gas.
NGL - Natural gas liquids - those hydrocarbons in natural gas that are separated from the gas as liquids through the process.
net - “net” natural gas or “net” acres are determined by adding the fractional ownership working interests the Company has in gross wells or acres.
TIL - turn-in-line; a well turned to sales.
blending - process of mixing dry and damp gas in order to meet downstream pipeline specifications.
proved reserves - quantities of oil, natural gas, and NGLs which, by analysis of geological 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 prior to the time at which 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.
proved developed reserves (PDPs) - proved reserves which can be expected to be recovered through existing wells with existing equipment and operating methods.
proved undeveloped reserves (PUDs) - proved reserves that can be estimated with reasonable certainty to be recovered from new wells on undrilled proved acreage or from existing wells where a relatively major expenditure is required for completion.
reservoir - a porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs.
development well - a well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.
exploratory well - a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well or a stratigraphic test well.
gob well - a well drilled or vent hole converted to a well which produces or is capable of producing coalbed methane or other natural gas from a distressed zone created above and below a mined-out coal seam by any prior full seam extraction of the coal.
service well - a well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include, among other things, gas injection, water injection and salt-water disposal.
play - a proven geological formation that contains commercial amounts of hydrocarbons.

royalty interest - the land owner's share of oil or gas production, typically 1/8.
throughput - the volume of natural gas transported or passing through a pipeline, plant, terminal, or other facility during a particular period.
working interest - an interest that gives the owner the right to drill, produce and conduct operating activities on a property and receive a share of any production.
wet gas - natural gas that contains significant heavy hydrocarbons, such as propane, butane and other liquid hydrocarbons.

FORWARD-LOOKING STATEMENTS

We are including the following cautionary statement in this Annual Report on Form 10-K to make applicable and take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by, or on behalf of us. With the exception of historical matters, the matters discussed in this Annual Report on Form 10-K are forward-looking statements (as defined in Section 21E of the Securities Exchange Act of 1934, as amended (the Exchange Act)) that involve risks and uncertainties that could cause actual results to differ materially from projected results. Accordingly, investors should not place undue reliance on forward-looking statements as a prediction of actual results. The forward-looking statements may include projections and estimates concerning the timing and success of specific projects and our future production, revenues, income and capital spending. When we use the words “believe,” “intend,” “expect,” “may,” “should,” “anticipate,” “could,” “e “plan,” “predict,” “project,” "will," or their negatives, or other similar expressions, the statements which include those words are usually forward-looking statements. When we describe strategy that involves risks or uncertainties, we are making forward-looking statements. The forward-looking statements in this Annual Report on Form 10-K speak only as of the date of this Annual Report on Form 10-K; we disclaim any obligation to update these statements unless required by securities law, and we caution you not to rely on them unduly. We have based these forward-looking statements on our current expectations and assumptions about future events. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond our control. These risks, contingencies and uncertainties relate to, among other matters, the following:

- prices for natural gas and natural gas liquids are volatile and can fluctuate widely based upon a number of factors beyond our control including oversupply relative to the demand for our products, weather and the price and availability of alternative fuels;
- our dependence on gathering, processing and transportation facilities and other midstream facilities owned by CNX Midstream Partners LP (NYSE: CNXM) (CNXM) and others;
- uncertainties in estimating our economically recoverable natural gas reserves, and inaccuracies in our estimates;
- the high-risk nature of drilling and developing natural gas wells;
- our identified drilling locations are scheduled out over multiple years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling;
- challenges associated with strategic determinations, including the allocation of capital and other resources to strategic opportunities;
- our development and exploration projects, as well as CNXM’s midstream system development, require substantial capital expenditures;
- the impact of potential, as well as any adopted environmental regulations including any relating to greenhouse gas emissions on our operating costs as well as on the market for natural gas and for our securities;
- environmental regulations can increase costs and introduce uncertainty that could adversely impact the market for natural gas with potential short and long-term liabilities;
- our operations are subject to operating risks that could increase our operating expenses and decrease our production levels which could adversely affect our results of operation and our operations are also subject to hazards and any losses or liabilities we suffer from hazards, which occur in our operations may not be fully covered by our insurance policies;
- decreases in the availability of, or increases in the price of, required personnel, services, equipment, parts and raw materials in sufficient quantities or at reasonable costs to support our operations;
- if natural gas prices decrease or drilling efforts are unsuccessful, we may be required to record write-downs of our proved natural gas properties;
- changes in assumptions impacting management’s estimates of future financial results as well as other assumptions such as movement in our stock price, weighted-average cost of capital, terminal growth rates and industry multiples,

could cause goodwill and other intangible assets we hold to become impaired and result in material non-cash charges to earnings;

- a loss of our competitive position because of the competitive nature of the natural gas industry, consolidation within the industry or overcapacity in the industry adversely affecting our ability to sell our products and midstream services, which could impair our profitability;
- deterioration in the economic conditions in any of the industries in which our customers operate, a domestic or worldwide financial downturn, or negative credit market conditions;
- hedging activities may prevent us from benefiting from price increases and may expose us to other risks;
- existing and future government laws, regulations and other legal requirements and judicial decisions that govern our business may increase our costs of doing business and may restrict our operations;
- significant costs and liabilities may be incurred as a result of pipeline operations and related increase in the regulation of gas gathering pipelines;

- our ability to find adequate water sources for our use in shale gas drilling and production operations, or our ability to dispose of, transport or recycle water used or removed in connection with our gas operations at a reasonable cost and within applicable environmental rules;
- failure to find or acquire economically recoverable natural gas reserves to replace our current natural gas reserves;
- risks associated with our debt;
- a decrease in our borrowing base, which could decrease for a variety of reasons including lower natural gas prices, declines in natural gas proved reserves, asset sales and lending requirements or regulations;
- changes in federal or state income tax laws;
- cyber-incidents could have a material adverse effect on our business, financial condition or results of operations;
- construction of new gathering, compression, dehydration, treating or other midstream assets by CNXM may not result in revenue increases and may be subject to regulatory, environmental, political, legal and economic risks;
- our success depends on key members of our management and our ability to attract and retain experienced technical and other professional personnel;
- terrorist activities could materially and adversely affect our business and results of operations;
- we may operate a portion of our business with one or more joint venture partners or in circumstances where we are not the operator, which may restrict our operational and corporate flexibility and we may not realize the benefits we expect to realize from a joint venture;
- acquisitions and divestitures we anticipate may not occur or produce anticipated benefits;
- the outcomes of various legal proceedings, including those which are more fully described in our reports filed under the Exchange Act;
- there is no guarantee that we will continue to repurchase shares of our common stock under our current or any future share repurchase program at levels undertaken previously or at all;
- negative public perception regarding our industry could have an adverse effect on our operations;
- CONSOL Energy may not be able to satisfy its indemnification obligations in the future and such indemnities may not be sufficient to hold us harmless from the full amount of liabilities for which CONSOL Energy will be allocated responsibility;
- the separation of CONSOL Energy could result in substantial tax liability; and
- other factors discussed in this 2018 Form 10-K under “Risk Factors,” as updated by any subsequent Forms 10-Q, which are on file with the Securities and Exchange Commission.

PART I

ITEM 1. Business

General

CNX Resources Corporation (CNX or the Company) is a premiere independent oil and gas company that is focused on the exploration, development, production, gathering, processing and acquisition of natural gas properties primarily in the Appalachian Basin. Our operations are centered on unconventional shale formations, primarily the Marcellus Shale and Utica Shale.

CNX was incorporated in Delaware in 1991 under the name CONSOL Energy Inc. (CONSOL Energy), but its predecessors had been mining coal, primarily in the Appalachian Basin, since 1864. CNX entered the natural gas business in the 1980s initially to increase the safety and efficiency of its Virginia coal mines by capturing methane from coal seams prior to mining, which makes the mining process safer and more efficient. The natural gas business grew from the coalbed methane production in Virginia into other unconventional production, including hydraulic fracturing in the Marcellus Shale and Utica Shale in the Appalachian Basin. This growth was accelerated with the 2010 asset acquisition of the Appalachian Exploration & Production business of Dominion Resources, Inc.

On November 28, 2017, CNX completed the tax-free spin-off of its coal business resulting in two independent, publicly traded companies: CONSOL Energy, a coal company, formerly known as CONSOL Mining Corporation; and CNX, a natural gas exploration and production company. As a result of the separation of the two companies, CONSOL Energy and its subsidiaries now hold the coal assets previously held by CNX, including its Pennsylvania Mining Complex, Baltimore Marine Terminal, its direct and indirect ownership interest in CONSOL Coal Resources LP, formerly known as CNXC Coal Resources LP, and other related coal assets previously held by CNX. The coal company, previously reported as the Company's Pennsylvania Mining Operations division, has been reclassified in the Audited Consolidated Financial Statements in Item 8 of this Annual Report on Form 10-K (the Form 10-K) to discontinued operations in 2017 as well as all prior periods presented.

CNX operates, develops and explores for natural gas in Appalachia (Pennsylvania, West Virginia, Ohio, and Virginia). Our primary focus is the continued development of our Marcellus Shale acreage and delineation and development of our unique Utica Shale acreage and stacked pay opportunity set. We believe that our concentrated operating area, our legacy surface acreage position, our regional operating expertise, our extensive data set from development, as well as from non-operated participation wells and our held-by-production acreage position provides us a significant competitive advantage over our competitors. Over the past ten years, CNX's natural gas production has grown by approximately 570% to produce a total of 507.1 net Bcfe in 2018, which includes approximately 27 Bcfe of production related to assets that were sold during the year. For additional information, see Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K and incorporated herein.

Our land holdings in the Marcellus Shale and Utica Shale plays cover large areas, provide multi-year drilling opportunities and, collectively, have sustainable lower-risk growth profiles. We currently control approximately 539,000 net acres in the Marcellus Shale and approximately 627,000 net acres that have Utica Shale potential in Ohio, West Virginia, and Pennsylvania. We also have approximately 2.5 million net acres in our coalbed methane play.

Highlights of our 2018 production include the following:
- Total average production of 1,389,325 Mcfe per day;
- 92% Natural Gas, 8% Liquids; and
- 57% Marcellus, 30% Utica, 12% coalbed methane, and 1% other.

At December 31, 2018, our proved natural gas, NGL, condensate and oil reserves (collectively, "natural gas reserves") had the following characteristics:

- 7.9 Tcfe of proved reserves;
- 94.4% natural gas;
- 57.0% proved developed;
- 98.6% operated; and
- A reserve life ratio of 15.54 years (based on 2018 production).

The following map provides the location of CNX's E&P operations by region:
CNX defines itself through its core values which serve as the compass for our road map and guide every aspect of our business as we strive to achieve our corporate mission:

- Responsibility: Be a safe and compliant operator; be a trusted community partner and respected corporate citizen; act with pride and integrity;
- Ownership: Be accountable for our actions and learn from our outcomes, both positive and negative; be calculated risk-takers and seek creative ways to solve problems; and
- Excellence: Be prudent capital allocators; be a lean, efficient, nimble organization; be a disciplined, reliable, performance-driven company.

These values are the foundation of CNX's identity and are the basis for how management defines continued success. We believe CNX's rich resource base, coupled with these core values, allows management to create value for the long-term. The U.S. electric power industry generates more than half of its output by burning fossil fuels. We believe that the use of natural gas as one of the principal fuel sources for electricity in the United States will continue for many years; in fact, the Energy Information Agency (EIA) forecasts that U.S. electricity generation from natural gas will increase by 40% by 2030 and by more than 50% by 2040. Natural gas is the dominant choice for space and water heating fuel in the U.S. domestic residential sector, and EIA forecasts gas consumption for this use to increase modestly over the next decades. Plentiful natural gas is also creating growing opportunities as feedstock for chemicals, plastics, and fertilizer manufacturing in the U.S. and for rapidly expanding exports, as the U.S. becomes a net exporter of the fuel. Additionally, we believe that, as both worldwide economies and U.S. export facilities expand, the demand for our natural gas will grow as well.

CNX's Strategy

CNX's strategy is to increase shareholder value through the development and growth of its existing natural gas assets and selective acquisition of natural gas and NGL acreage leases within its footprint. Our mission is to empower our team to embrace and drive innovative change that creates long-term per share value for our investors, enhances our communities and delivers energy solutions for today and tomorrow. We will also continue to focus on the monetization of non-core assets to accelerate value creation and to minimize any shortfall between operating cash flows and our growth capital requirements.

We expect natural gas to continue to be the dominant contributor to the domestic electricity generation mix, while fueling industrial growth in the U.S. economy. EIA forecasts that natural gas will be the single dominant fuel (including renewables and nuclear as “fuels”) for electricity generation out through 2050, and that total domestic natural gas consumption will increase 19% in that time. The Gas Exporting Countries Forum (GECF) forecasts global demand for gas to increase by 46% to 5.43 trillion cubic meters by 2040, according to the "Global Gas Outlook 2040". It also stated that generating electricity and the industrial sector will contribute the most to the growing demand and that the share of natural gas in the global energy balance will increase from 22% to 26% by 2040. With the recent growth of natural gas exports to Mexico and Canada, the United States becoming a net exporter of natural gas, and increasing liquefied natural gas (LNG) demand, we expect new markets to open in the coming years. We believe that our growth in natural gas production, our low drilling and operating costs, our leverage and liquidity positions, and our vast acreage will allow CNX to take advantage of these markets.

CNX's Capital Expenditure Budget

In 2019, CNX expects capital expenditures of approximately $1,000-$1,080 million. The 2019 budget includes $575-$625 million of drilling and completion ("D&C") capital and approximately $175 million of capital associated with land, midstream, and water infrastructure and $250-$280 million of capital for CNX Midstream Partners LP ("CNXM"). The company continuously evaluates multiple factors to determine incremental activity throughout the year, and as such may update guidance accordingly.

DETAIL OPERATIONS

Our operations are located throughout Appalachia and include the following plays:

Marcellus Shale

We have the rights to extract natural gas in Pennsylvania, West Virginia, and Ohio from approximately 539,000 net Marcellus Shale acres at December 31, 2018.

The Upper Devonian Shale formation, which includes both the Burkett Shale and Rhinestreet Shale, lies above the Marcellus Shale formation in southwestern Pennsylvania and northern West Virginia. The Company holds approximately 45,000 acres of incremental Upper Devonian acres; however, these acres have historically not been disclosed separately as they generally coincide with our Marcellus acreage.

On January 3, 2018, the Company acquired the remaining 50% membership interest in CONE Gathering LLC (which has since been renamed CNX Gathering LLC), which holds the general partner interest and incentive distribution rights in CNXM, the entity that constructs and operates the gathering system for most of our Marcellus shale production. See **"Midstream Gas Services"** for a more detailed explanation.

Utica Shale

We have the rights to extract natural gas in Pennsylvania, West Virginia, and Ohio from approximately 627,000 net Utica Shale acres at December 31, 2018. Approximately 356,000 Utica acres coincide with Marcellus Shale acreage in Pennsylvania, West Virginia, and Ohio. During the third quarter of 2018, CNX closed on the sale of substantially all of its Ohio Utica Joint Venture Assets, including approximately 35,000 net acres in the wet gas Utica Shale areas of Belmont, Guernsey, Harrison, and Noble Counties (See Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for more information).

Coalbed Methane (CBM)

We have the rights to extract CBM in Virginia from approximately 308,000 net CBM acres in Central Appalachia. We produce CBM natural gas primarily from the Pocahontas #3 seam and still have a nominal drilling program.

We also have the rights to extract CBM from approximately 2,100,00 net CBM acres in other states including West Virginia, Pennsylvania, Ohio, Illinois, Indiana and New Mexico with no current plans to drill CBM wells in these areas.

Other Gas

We have the rights to extract natural gas from other shale and shallow oil and gas positions primarily in Illinois, Indiana, New York, Ohio, Pennsylvania, Virginia, and West Virginia from approximately 968,000 net acres at December 31, 2018. The majority of our shallow oil and gas leasehold position is held by production and all of it is extensively overlain by existing third-party gas gathering and transmission infrastructure. In March 2018, CNX Gas completed the sale of substantially all of its shallow oil and gas assets in Pennsylvania and West Virginia, including approximately 833,000 net acres (See Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for more information).

Summary of Properties as of December 31, 2018

	Marcellus Segment	**Utica Segment**	**CBM Segment**	**Other Gas Segment**	**Total**
Estimated Net Proved Reserves (MMcfe)	5,595,409	1,067,617	1,209,638	8,671	7,881,335
Percent Developed	54 %	49 %	77 %	100 %	57 %
Net Producing Wells (including oil and gob wells)	355	45	4,152	71	4,623
Net Acreage Position:					
Net Proved Developed Acres	42,853	12,090	231,415	3,244	289,602
Net Proved Undeveloped Acres	26,324	7,046	—	—	33,370
Net Unproved Acres(1)	515,073	252,473	2,227,764	965,118	3,960,428
Total Net Acres(2)	584,250	271,609	2,459,179	968,362	4,283,400

(1) Net acres include acreage attributable to our working interests in the properties. Additional adjustments (either increases or decreases) may be required as we further develop title to and further confirm our rights with respect to our various properties in anticipation of development. We believe that our assumptions and methodology in this regard are reasonable.

(2) Acreage amounts are only included under the target strata CNX expects to produce with the exception of certain CBM acres governed by separate leases, although the reported acres may include rights to multiple gas seams (e.g. we have rights to the Marcellus segment that are disclosed under the Utica segment and we have rights to Utica segment that are disclosed under the Marcellus segment). We have reviewed our drilling plans, and our acreage rights and have used our best judgment to reflect the acres in the strata we expect to primarily produce. As more information is obtained or circumstances change, the acreage classification may change.

Producing Wells and Acreage

Most of our development wells and proved acreage are located in Virginia, West Virginia, Ohio and Pennsylvania. Some leases are beyond their primary term, but these leases are extended in accordance with their terms as long as certain drilling commitments or other term commitments are satisfied.

The following table sets forth, at December 31, 2018, the number of producing wells, developed acreage and undeveloped acreage:

	Gross	**Net(1)**
Producing Gas Wells (including gob wells)	6,453	4,623
Producing Oil Wells	149	1
Net Acreage Position:		
Proved Developed Acreage	289,602	289,602
Proved Undeveloped Acreage	33,370	33,370
Unproved Acreage	4,940,180	3,960,428
Total Acreage	5,263,152	4,283,400

(1) Net acres include acreage attributable to our working interests in the properties. Additional adjustments (either increases or decreases) may be required as we further develop title to and further confirm our rights with respect to our various properties in anticipation of development. We believe that our assumptions and methodology in this regard are reasonable.

The following table represents the terms under which we hold these acres:

	Gross Unproved Acres	Net Unproved Acres	Net Proved Undeveloped Acres
Held by production/fee	4,797,145	3,896,613	18,524
Expiration within 2 years	87,553	37,115	7,628
Expiration beyond 2 years	55,482	26,700	7,218
Total Acreage	4,940,180	3,960,428	33,370

The leases reflected above as Gross and Net Unproved Acres with expiration dates are included in our current drill plan or active land program. Leases with expiration dates within two years represent approximately 1% of our total net unproved acres and leases with expiration dates beyond two years represent approximately 1% of our total net unproved acres. In each case, we deemed this acreage to not be material to our overall acreage position. Additionally, based on our current drill plans and lease management we do not anticipate any material impact to our consolidated financial statements from the expiration of such leases.

Development Wells (Net)

During the years ended December 31, 2018, 2017 and 2016, we drilled 83.9, 90.0 and 36.0 net development wells, respectively. Gob wells and wells drilled by operators other than our primary joint venture partners at that time are excluded from net development wells. In 2018, there were 22.0 net development wells and no exploratory wells drilled but uncompleted. There were no dry development wells in 2018, 2017, or 2016. As of December 31, 2018, there are 8.0 gross completed developmental wells ready to be turned in-line. The following table illustrates the net wells drilled by well classification type:

	For the Year Ended December 31,		
	2018	2017	2016
Marcellus segment	65.9	9.0	—
Utica segment	12.0	17.0	13.0
CBM segment	6.0	64.0	23.0
Other Gas segment	—	—	—
Total Development Wells (Net)	83.9	90.0	36.0

Exploratory Wells (Net)

There were no exploratory wells drilled during the year ended December 31, 2018. There were 4.0 net exploratory wells drilled during the year ended December 31, 2017 and no exploratory wells drilled during the year ended December 31, 2016. As of December 31, 2018, there are 4.0 net exploratory wells in process. The following table illustrates the exploratory wells drilled by well classification type:

	For the Year Ended December 31,								
	2018			2017			2016		
	Producing	Dry	Still Eval.	Producing	Dry	Still Eval.	Producing	Dry	Still Eval.
Marcellus segment	—	—	—	—	—	—	—	—	—
Utica segment	—	—	—	4.0	—	—	—	—	—
CBM segment	—	—	—	—	—	—	—	—	—
Other Gas segment	—	—	—	—	—	—	—	—	—
Total Exploratory Wells (Net)	—	—	—	4.0	—	—	—	—	—

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Reserves

The following table shows our estimated proved developed and proved undeveloped reserves. Reserve information is net of royalty interest. Proved developed and proved undeveloped reserves are reserves that could be commercially recovered under current economic conditions, operating methods and government regulations. Proved developed and proved undeveloped reserves are defined by the Securities and Exchange Commission (SEC).

	Net Reserves (Million cubic feet equivalent) as of December 31,		
	2018	**2017**	**2016**
Proved developed reserves	4,494,878	4,409,065	3,683,302
Proved undeveloped reserves	3,386,457	3,172,547	2,568,346
Total proved developed and undeveloped reserves(1)	7,881,335	7,581,612	6,251,648

(1) For additional information on our reserves, see Other Supplemental Information–Supplemental Gas Data (unaudited) to the Consolidated Financial Statements in Item 8 of this Form 10-K.

Discounted Future Net Cash Flows

The following table shows our estimated future net cash flows and total standardized measure of discounted future net cash flows at 10%:

	Discounted Future Net Cash Flows (Dollars in millions)		
	2018	**2017**	**2016**
Future net cash flows	$13,132	$7,841	$2,419
Total PV-10 measure of pre-tax discounted future net cash flows (1)	$6,172	$4,140	$1,559
Total standardized measure of after tax discounted future net cash flows	$4,655	$3,131	$955

(1) We calculate our present value at 10% (PV-10) in accordance with the following table. Management believes that the presentation of the non-Generally Accepted Accounting Principles (GAAP) financial measure of PV-10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and gas companies. Because many factors that are unique to each individual company impact the amount of future income taxes estimated to be paid, the use of a pre-tax measure is valuable when comparing companies based on reserves. PV-10 is not a measure of the financial or operating performance under GAAP. PV-10 should not be considered as an alternative to the standardized measure as defined under GAAP. We have included a reconciliation of the most directly comparable GAAP measure-after-tax discounted future net cash flows.

Reconciliation of PV-10 to Standardized Measure

	As of December 31,		
	2018	2017	2016
	(Dollars in millions)		
Future cash inflows	$26,610	$19,262	$11,303
Future production costs	(7,730)	(7,234)	(5,851)
Future development costs (including abandonments)	(1,600)	(1,711)	(1,550)
Future net cash flows (pre-tax)	17,280	10,317	3,902
10% discount factor	(11,108)	(6,177)	(2,343)
PV-10 (Non-GAAP measure)	6,172	4,140	1,559
Undiscounted income taxes	(4,147)	(2,476)	(1,483)
10% discount factor	2,630	1,467	879
Discounted income taxes	(1,517)	(1,009)	(604)
Standardized GAAP measure	$4,655	$3,131	$955

Gas Production

The following table sets forth net sales volumes produced for the periods indicated:

	For the Year Ended December 31,		
	2018	2017	2016
Natural Gas			
Sales Volume (MMcf)			
Marcellus	255,127	209,687	186,812
Utica	148,117	70,708	71,277
CBM	60,268	65,373	68,971
Other	4,714	19,125	21,693
Total	468,226	364,893	348,753
NGL			
Sales Volume (Mbbls)			
Marcellus	5,227	4,604	3,922
Utica	853	1,851	2,787
Other	1	1	1
Total	6,081	6,456	6,710
Oil and Condensate			
Sales Volume (Mbbls)			
Marcellus	286	346	360
Utica	78	204	470
Other	35	39	65
Total	399	589	895
Total Sales Volume (MMcfe)			
Marcellus	288,203	239,387	212,504
Utica	153,704	83,038	90,820
CBM	60,268	65,373	68,971
Other	4,929	19,368	22,092
Total	507,104	407,166	394,387

***Oil, NGLs, and Condensate are converted to Mcfe at the rate of one barrel equals six Mcf based upon the approximate relative energy content of oil and natural gas.**

Note: 2018 production includes approximately 27 Bcfe of production related to assets that were sold during the year. For additional information, see Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K and incorporated herein.

CNX expects a minimum base for 2019 annual natural gas production volumes of 495-515 Bcfe, which equates to an approximately 5% annual increase, based on the midpoint of guidance, compared to 2018 volumes when excluding production from assets that were sold.

Average Sales Price and Average Lifting Cost

The following table sets forth the total average sales price and the total average lifting cost for all of our natural gas and NGL production for the periods indicated. Total lifting cost is the cost of raising gas to the gathering system and does not include depreciation, depletion or amortization. See Part II Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations in this Form 10-K for a breakdown by segment.

	For the Year Ended December 31,		
	2018	**2017**	**2016**
Average Sales Price - Gas (Mcf)	$2.97	$2.59	$1.92
(Loss) Gain on Commodity Derivative Instruments - Cash Settlement- Gas (Mcf)	$(0.15)	$(0.11)	$0.70
Average Sales Price - NGLs (Mcfe)*	$4.55	$4.03	$2.42
Average Sales Price - Oil (Mcfe)*	$9.89	$7.56	$6.15
Average Sales Price - Condensate (Mcfe)*	$8.43	$6.59	$4.58
Total Average Sales Price (per Mcfe) Including Effect of Derivative Instruments	$2.97	$2.66	$2.63
Total Average Sales Price (per Mcfe) Excluding Effect of Derivative Instruments	$3.11	$2.76	$2.01
Average Lifting Costs Excluding Ad Valorem and Severance Taxes (per Mcfe)	$0.19	$0.22	$0.24
Average Sales Price - NGLs (Bbl)	$27.30	$24.18	$14.52
Average Sales Price - Oil (Bbl)	$59.34	$45.36	$36.90
Average Sales Price - Condensate (Bbl)	$50.58	$39.54	$27.48

***Oil, NGLs, and Condensate are converted to Mcfe at the rate of one barrel equals six Mcf based upon the approximate relative energy content of oil and natural gas.**

Sales of NGLs, condensates and oil enhance our reported natural gas equivalent sales price. Across all volumes, when excluding the impact of hedging, sales of liquids added $0.14 per Mcfe, $0.17 per Mcfe, and $0.09 per Mcfe for 2018, 2017, and 2016, respectively, to average gas sales prices. CNX expects to continue to realize a liquids uplift benefit as additional wells are turned-in-line, primarily in the liquid-rich areas of the Marcellus shale. We continue to sell the majority of our NGLs through the large midstream companies that process our natural gas. This approach allows us to take advantage of the processors’ transportation efficiencies and diversified markets. Certain of CNX’s processing contracts provide for the ability to take our NGLs “in-kind” and market them directly if desired. The processed purity products are ultimately sold to industrial, commercial, and petrochemical markets.

We enter into physical natural gas sales transactions with various counterparties for terms varying in length. Reserves and production estimates are believed to be sufficient to satisfy these obligations. In the past, we have delivered quantities required under these contracts. We also enter into various natural gas swap transactions. These gas swap transactions exist parallel to the underlying physical transactions and represented approximately 356.3 Bcf of our produced gas sales volumes for the year ended December 31, 2018 at an average price of $2.76 per Mcf. The notional volumes associated with these gas swaps represented approximately 312.2 Bcf of our produced gas sales volumes for the year ended December 31, 2017 at an average price of $2.60 per Mcf. As of January 18, 2019, these physical and swap transactions represent approximately 376.0 Bcf of our estimated 2019 production at an average price of $2.71 per Mcf, 468.6 Bcf of our estimated 2020 production at an average price of $2.55 per Mcf, 410.3 Bcf of our estimated 2021 production at an average price of $2.44 per Mcf, approximately 276.6 Bcf of our estimated 2022 production at an average price of $2.48 per Mcf, and approximately 127.0 Bcf of our estimated 2023 production at an average price of $2.35 per Mcf.

The hedging strategy and information regarding derivative instruments used are outlined in Part II, Item 7A Qualitative and Quantitative Disclosures About Market Risk and in Note 21 - Derivative Instruments in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K.

Midstream Gas Services

E&P Midstream Gas Services

CNX has traditionally designed, built and operated natural gas gathering systems to move gas from the wellhead to interstate pipelines or other local sales points. In addition, overtime CNX has acquired extensive gathering assets. CNX now owns or operates approximately 2,500 miles of natural gas gathering pipelines as well as a number of natural gas processing facilities. These assets are part of the E&P Division (See Note 24 - Segment Information in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for more information).

CNX's Midstream Division (see below) owns substantially all of CNX's Marcellus Shale gathering systems. With respect to the Utica Shale, CNX primarily contracts with third-party gathering services.

CNX has developed a diversified portfolio of firm transportation capacity options to support its production growth plan. CNX plans to selectively acquire firm capacity on an as-needed basis, while minimizing transportation costs and long-term financial obligations. Optimization of our firm transportation portfolio may also include, from time to time and as appropriate, releasing firm transportation to others. CNX also benefits from the strategic location of our primary production areas in southwestern Pennsylvania, northern West Virginia, and eastern Ohio. These areas are currently served by a large concentration of major pipelines that provide us with access to major gas markets without the necessity of transporting our gas out of the region and it is expected that recently-approved and pending pipeline projects will increase the take-away capacity from our region. In addition to firm transportation capacity, CNX has developed a processing portfolio to support the projected volumes from its wet gas production areas and has the operational and contractual flexibility to potentially convert a portion of currently processed wet gas volumes to be marketed as dry gas volumes, or vice-versa, as economically appropriate.

CNX has the advantage of having natural gas production from CBM and lower Btu Utica wells in close proximity to higher Btu Marcellus wells. Separately, the low Btu CBM gas and the high Btu Marcellus gas may need processing in order to meet downstream pipeline specifications. However, the geographic proximity and interconnected gathering system servicing these wells allow CNX to blend this gas together and in some cases eliminate the need for the costly processing of gas that does not meet pipeline specification. These different gas types allow us more flexibility in bringing Marcellus and Utica shale wells on-line at qualities that meet interstate pipeline specifications.

Midstream Division

On January 3, 2018, CNX closed its previously announced acquisition of Noble Energy’s (Noble) 50% membership interest in CONE Gathering LLC, which holds the general partner interest and incentive distribution rights in CONE Midstream Partners LP. In conjunction with the closing, CONE Midstream Partners LP was renamed CNX Midstream Partners LP (CNX Midstream or CNXM) and CONE Gathering LLC was renamed CNX Gathering LLC (CNX Gathering) (See Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for more information). Also on January 3, 2018, the Company’s board of directors authorized CNX Midstream to enter into an amendment to its gas gathering agreement with CNX Gas Company LLC, a wholly-owned subsidiary of CNX.

CNX Gathering develops, operates and owns substantially all of CNX’s Marcellus Shale gathering systems. Prior to its acquisition of Noble’s interest, CNX accounted for its interest in CNX Gathering under the equity method of accounting. Subsequent to the acquisition, CNX is the single sponsor of CNXM, and beginning in the first quarter of 2018 CNX Gathering was consolidated into the Company’s financial statements as the Midstream Division (See Note 24 - Segment Information in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for more information. We believe that the network of right-of-ways, vast surface holdings, experience in building and operating gathering systems in the Appalachian basin, and increased control and flexibility will give CNX Gathering an advantage in building the midstream assets required to execute our Marcellus Shale development plan.

Natural Gas Competition

The United States natural gas industry is highly competitive. CNX competes with other large producers, as well as a myriad of smaller producers and marketers. CNX also competes for pipeline and other services to deliver its products to customers. According to data from the Natural Gas Supply Association and the Energy Information Agency (EIA), the five largest U.S. producers of natural gas produced about 14% of dry natural gas production during the first ten months of 2018. The EIA reported 485,383 producing natural gas wells in the United States at December 31, 2017 (the latest year for which government statistics are available), which is approximately 15% lower than 2016.

CNX expects natural gas to continue to be a significant contributor to the domestic electric generation mix in the long-term, as well as to fuel industrial growth in the U.S. economy. According to the EIA, natural gas represented 35% of U.S. electricity generation during the twelve months ended October 31, 2018, up from 32% in 2017. According to the EIA, from January through June of 2018, net natural gas exports from the United States averaged 0.87 billion cubic feet per day (Bcf/d), more than double the average daily net exports during all of 2017 (0.34 Bcf/d). The United States, which became a net natural gas exporter on an annual basis in 2016 for the first time in almost 60 years, has continued to export more natural gas than it imports for five of the first six months in 2018. U.S. natural gas exports have increased primarily with the addition of new LNG export facilities in the Lower 48 states. The EIA also states that U.S. exports of LNG through the first half of 2018 rose 58% compared with the same period in 2017. CNX expects the high level of U.S. gas exports to continue in the future. In addition, there is potential for natural gas to become a significant contributor to the transportation market. The EIA currently expects overall demand for U.S. natural gas in 2019 to increase 1.3% from 2018. CNX estimates 2019 in-basin (Ohio, West Virginia, and Pennsylvania) demand to increase by approximately 3% compared with 2018. Our increasing gas production will allow CNX to participate in growing markets.

CNX gas operations are primarily located in the eastern United States, specifically the Appalachian Basin. The gas market is highly fragmented and not dominated by any single producer. We believe that competition among producers is based primarily on acreage position, low drilling and operating costs as well as pipeline transportation availability to the various markets.

Continued demand for CNX's natural gas and the prices that CNX obtains are affected by natural gas use in the production of electricity, pipeline capacity, U.S. manufacturing and the overall strength of the economy, environmental and government regulation, technological developments, the availability and price of competing alternative fuel supplies, and national and regional supply/demand dynamics.

Non-Core Mineral Assets and Surface Properties

CNX owns significant natural gas assets that are not in our short-term or medium-term development plans. We continually explore the monetization of these non-core assets by means of sale, lease, contribution to joint ventures, or a combination of the foregoing in order to bring the value of these assets forward for the benefit of our shareholders. We also control a significant amount of surface acreage. This surface acreage is valuable to us in the development of the gathering system for our Marcellus Shale and Utica Shale production. We also derive value from this surface control by granting rights of way or development rights to third-parties when we are able to derive appropriate value for our shareholders.

Water Division

CNX Water Assets LLC (CNX Water) is a wholly-owned subsidiary of CNX and supplies turnkey solutions for water sourcing, delivery and disposal for our natural gas operations, and supplies solutions for water sourcing as well as delivery and disposal for third-parties. In coordination with our midstream operations, CNX Water works to develop solutions that coincide with our midstream operations to offer gas gathering and water delivery solutions in one package to third-parties.

Employee and Labor Relations

At December 31, 2018, CNX had 564 employees, none of whom are subject to a collective bargaining agreement.

Industry Segments

Financial information concerning industry segments, as defined by accounting principles generally accepted in the United States, for the years ended December 31, 2018, 2017 and 2016 is included in Note 24 - Segment Information in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K and incorporated herein.

Financial Information about Geographic Areas

All of the Company's assets and operations are located in the continental United States.

Laws and Regulations

General

Our natural gas and midstream operations are subject to various federal, state and local (including county and municipal level) laws and regulations. These laws and regulations cover virtually every aspect of our operations including, among other things: use of public roads; construction of well pads, impoundments, tanks and roads; pooling and unitizations; water withdrawal and procurement for well stimulation purposes; well drilling, casing and hydraulic fracturing; stormwater management; well production; well plugging; venting or flaring of natural gas; pipeline construction and the compression and transmission of natural gas and liquids; reclamation and restoration of properties after natural gas operations are completed; handling, storage, transportation and disposal of materials used or generated by natural gas operations; the calculation, reporting and payment of taxes on gas production; and gathering of natural gas production. Numerous governmental permits, authorizations and approvals under these laws and regulations are required for natural gas and midstream operations. These laws and regulations, and the permits, authorizations and approvals issued pursuant to those laws and regulations, are intended to protect, among other things: air quality; ground water and surface water resources, including drinking water supplies; wetlands; waterways; endangered plants and wildlife; state natural resources and the health and safety of our employees and the communities in which we operate.

Additionally, the electric power generation industry, which consumes significant quantities of natural gas, remains subject to extensive regulation regarding the environmental impact of its power generation activities, which could impact demand for our natural gas.

We endeavor to conduct our natural gas and midstream operations in compliance with all applicable federal, state and local laws and regulations. However, because of extensive and comprehensive regulatory requirements against a backdrop of variable geologic and seasonal conditions, permit exceedances and violations during operations can and do occur. Such exceedances and violations generally result in fines or penalties but could make it more difficult for us to obtain necessary permits in the future. The possibility exists that new legislation or regulations may be adopted which would have a significant impact on our natural gas or midstream operations or on our customers' ability to use our natural gas and may require us or our customers to change their operations significantly or incur substantial costs. See “Risk Factors -- *Existing and future governmental laws, regulations and other legal requirements and judicial decisions that govern our business may increase our costs of doing business and may restrict our operations*” for additional discussion regarding additional laws and regulations affecting our business, operations and industry.

Environmental Laws

Many of the laws and regulations referred to above are state level environmental laws and regulations, which vary according to the state in which we are conducting operations. However, our natural gas and midstream operations are also subject to numerous federal level environmental laws and regulations.

In addition to routine reviews and inspections by regulators to confirm compliance with applicable regulatory requirements, CNX has established protocols for ongoing assessments to identify potential environmental exposures. These assessments take into account industry and internal best management practices and evaluate compliance with laws and regulations and include reviews of our third-party service providers, including, for instance, waste management facilities.

Hydraulic Fracturing Activities. Hydraulic fracturing is typically regulated by state oil and natural gas commissions and similar agencies, but the U.S. Environmental Protection Agency (“EPA”) has asserted certain regulatory authority over hydraulic fracturing and has moved forward with various regulatory actions, including the issuance of new regulations requiring green completions for hydraulically fractured wells, and has disclosed its intent to develop regulations to require companies to disclose information regarding the chemicals used in hydraulic fracturing. Some states, including states in which we operate, have adopted regulations that could impose more stringent disclosure and/or well construction requirements on hydraulic fracturing operations, or otherwise seek to ban some or all of these activities.

Scrutiny of hydraulic fracturing activities also continues in other ways. In June 2015, the EPA issued its draft report on the potential impacts of hydraulic fracturing on drinking water and groundwater. The draft report found no systemic negative impacts from hydraulic fracturing. In December 2016, the EPA released its final report on the impacts of hydraulic fracturing on drinking water. While the language was changed and included the possibility of negative impacts from hydraulic fracturing, it also included the guidance to industry and regulators on how the process can be performed safely. We cannot predict whether any other legislation or regulations will be enacted and if so, what its provisions will be.

Clean Air Act. The federal Clean Air Act and corresponding state laws and regulations regulate air emissions primarily through permitting and/or emissions control requirements. This affects natural gas production and processing operations. Various activities in our operations are subject to regulation, including pipeline compression, venting and flaring of natural gas, and hydraulic fracturing and completion processes, as well as fugitive emissions from operations. We obtain permits, typically from state or local authorities, to conduct these activities. Additionally, we are required to obtain pre-approval for construction or modification of certain facilities, to meet stringent air permit requirements, or to use specific equipment, technologies or best management practices to control emissions. Further, some states and the federal government have proposed that emissions from certain proximate and related sources should be aggregated to provide for regulation and permitting of a single, major source. Federal and state governmental agencies continue to investigate the potential for emissions from oil and natural gas activities, and further regulation could increase our cost or temporarily restrict our ability to produce. For example, the EPA sets National Ambient Air Quality Standards for certain pollutants and such changes which could cause us to make additional capital expenditures or alter our business operations in some manner. See *"Risk Factors - Regulation of greenhouse gas emissions at the federal or state level may increase our operating costs and reduce the value of our natural gas assets and such regulation, as well as uncertainty concerning such regulation, could adversely impact the market for natural gas, as well as for our securities."* for additional discussion regarding certain laws and regulations related to air emissions and related matters.

Clean Water Act. The federal Clean Water Act ("CWA") and corresponding state laws affect our natural gas operations by regulating storm water or other regulated substance discharges, including pollutants, sediment, and spills and releases of oil, brine and other substances, into surface waters, and in certain instances imposing requirements to dispose of produced wastes and other oil and gas wastes at approved disposal facilities. The discharge of pollutants into jurisdictional waters is prohibited, except in accordance with the terms of a permit issued by the EPA, the U.S. Army Corps of Engineers, or a delegated state agency. These permits require regular monitoring and compliance with effluent limitations and reporting requirements govern the discharge of pollutants into regulated waters. Federal and state regulatory agencies can impose administrative, civil and/or criminal penalties for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations. See *"Risk Factors -Environmental regulations can increase costs and introduce uncertainty that could adversely impact the market for natural gas with potential short and long-term liabilities*." for additional discussion regarding certain laws and regulations related to clean water, the disposal or use of water and related matters.

Endangered Species Act. The Endangered Species Act and related state regulation protect plant and animal species that are threatened or endangered. Some of our operations are located in areas that are or may be designated as protected habitats for endangered or threatened species, including the Northern Long-Eared and Indiana bats, which has a seasonal impact on our construction activities and operations. New or additional species that may be identified as requiring protection or consideration may lead to delays in permits and/or other restrictions.

Safety of Gas Transmission and Gathering Pipelines. Natural gas pipelines serving our operations are subject to regulation by the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration ("PHMSA") pursuant to the Natural Gas Pipeline Safety Act of 1968, ("NGPSA"), as amended by the Pipeline Safety Act of 1992, the Accountable Pipeline Safety and Partnership Act of 1996, the Pipeline Safety Improvement Act of 2002 ("PSIA"), the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006, and the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the "2011 Pipeline Safety Act"). The NGPSA regulates safety requirements in the design, construction, operation and maintenance of natural gas pipeline facilities, while the PSIA establishes mandatory inspections for all U.S. oil and natural gas transmission pipelines in high-consequence areas. Additionally, certain states, such as West Virginia, also maintain jurisdiction over intrastate natural gas lines. See "*Risk Factors -- We may incur significant costs and liabilities as a result of pipeline operations and related increase in the regulation of gas gathering pipelines*." for additional discussion regarding gas transmission and gathering pipelines.

Resource Conservation and Recovery Act. The federal Resource Conservation and Recovery Act (RCRA) and corresponding state laws and regulations affect natural gas operations by imposing requirements for the management, treatment, storage and disposal of hazardous and non-hazardous wastes, including wastes generated by natural gas operations. Facilities at which hazardous wastes have been treated, stored or disposed of are subject to corrective action orders issued by the EPA that could adversely affect our financial results, financial condition and cash flows. On December 28, 2016 the EPA entered into a consent order to resolve outstanding litigation brought by environmental and citizen groups regarding the applicability of RCRA to wastes from oil and gas development activities. The consent order requires the EPA to revise the applicability determination by March 15, 2019.

Federal Regulation of the Sale and Transportation of Natural Gas

Federal Energy Regulatory Commission. Regulations and orders issued by the Federal Energy Regulatory Commission (FERC) impact our natural gas business to a certain degree. Although the FERC does not directly regulate our natural gas production activities, the FERC has stated that it intends for certain of its orders to foster increased competition within all phases of the natural gas industry. Additionally, the FERC has jurisdiction over the transportation of natural gas in interstate commerce, and regulates the terms, conditions of service, and rates for the interstate transportation of our natural gas production. The FERC possesses regulatory oversight over natural gas markets, including anti-market manipulation regulation. The FERC has the ability to assess civil penalties, order disgorgement of profits and recommend criminal penalties for violations of the Natural Gas Act or the FERC’s regulations and policies thereunder.

Section 1(b) of the Natural Gas Act exempts natural gas gathering facilities from regulation by the FERC. However, the distinction between federally unregulated gathering facilities and FERC-regulated transmission facilities is a fact-based determination, and the classification of facilities is the subject of ongoing litigation. We own certain natural gas pipeline facilities that we believe meet the traditional tests which the FERC has used to establish a pipeline's status as a gatherer not subject to the FERC jurisdiction.

Natural gas prices are currently unregulated, but Congress historically has been active in the area of natural gas regulation. We cannot predict whether new legislation to regulate natural gas sales might be enacted in the future or what effect, if any, any such legislation might have on our operations.

Health and Safety Laws

Occupational Safety and Health Act. Our natural gas operations are subject to regulation under the federal Occupational Safety and Health Act (OSHA) and comparable state laws in some states, all of which regulate health and safety of employees at our natural gas operations. Additionally, OSHA's hazardous communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state laws require that information be maintained about hazardous materials used or produced by our natural gas operations and that this information be provided to employees, state and local governments and the public.

Climate Change Laws and Regulations

Climate change continues to be a legislative and regulatory focus. There are a number of proposed and final laws and regulations that limit greenhouse gas emissions, and regulations that restrict emissions could increase our costs should the requirements necessitate the installation new equipment or the purchase of emission allowances. These laws and regulations could also impact our customers, including the electric generation industry, making alternative sources of energy more competitive. Additional regulation could also lead to permitting delays and additional monitoring and administrative requirements, as well as to impacts on electricity generating operations. See *“Risk Factors - Regulation of greenhouse gas emissions at the federal or state level may increase our operating costs and reduce the value of our natural gas assets and such regulation, as well as uncertainty concerning such regulation, could adversely impact the market for natural gas, as well as for our securities.”* for additional discussion regarding certain laws and regulations related to climate change, greenhouse gas and related matters.

Title to Properties

CNX acquires ownership or leasehold rights to oil and natural gas properties prior to conducting operations on those properties. The legal requirements of such ownership or leasehold rights generally are established by state statutory or common law. As is customary in the natural gas industry, we have generally conducted only a summary review of the title to oil and gas rights that are not yet in our development plans, but which we believe we control. This summary review is conducted at the time of acquisition or as part of a review of our land records. Prior to the commencement of development operations on natural gas and coalbed methane properties, we conduct a thorough title examination and perform curative work with respect to significant title defects. Our discovering title defects which we are unable to cure may adversely impact our ability to develop those properties and we may have to reduce our estimated gas reserves including our proved undeveloped reserves. In accordance with the foregoing, we have completed title work on substantially all of our natural gas and coalbed methane properties that are currently producing and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the industry.

Available Information

CNX maintains a website at www.cnx.com. CNX makes available, free of charge, on this website our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act, as soon as reasonably practicable after such reports are available, electronically filed with, or furnished to the SEC. Those reports are also available at the SEC's: website www.sec.gov. Apart from SEC filings, we also use our website to publish information which may be important to investors, such as presentations to analysts.

Executive Officers of the Registrant

Incorporated by reference into this Part I is the information set forth in Part III, Item 10 under the caption "Executive Officers of CNX" (included herein pursuant to Item 401(b) of Regulation S-K).

ITEM 1A. Risk Factors

Investment in our securities is subject to various risks, including risks and uncertainties inherent in our business. The following sets forth factors related to our business, operations, financial position or future financial performance or cash flows which could cause an investment in our securities to decline and result in a loss.

Prices for natural gas and NGLs are volatile and can fluctuate widely based upon a number of factors beyond our control, including oversupply relative to the demand for our products, weather and the price and availability of alternative fuels. An extended decline in the prices we receive for our natural gas and NGLs will adversely affect our business, operating results, financial condition and cash flows.

Our financial results are significantly affected by the prices we receive for our natural gas and NGLs. Natural gas, NGLs, oil and condensate prices are very volatile and can fluctuate widely based upon supply from energy producers relative to demand for these products and other factors beyond our control. The disposition in 2017 of our entire coal operations has increased our exposure to fluctuations in the price of natural gas, NGLs, oil and condensate.

In particular, the U.S. natural gas industry continues to face concerns of oversupply due to the success of Marcellus and other new shale plays. The oversupply of natural gas in 2012 resulted in domestic prices hovering around ten-year lows, and drilling continued in these plays, despite these lower gas prices, to meet drilling commitments. Although gas prices have arguably recovered as of 2018, continued volatility remains a strong possibility.

Our producing properties are geographically concentrated in the Appalachian Basin, which exacerbates the impact of regional supply and demand factors on our business, including the pricing of our gas. The success of the Marcellus Shale and Utica Shale plays has resulted in growth in natural gas production in this region, with production per day in Pennsylvania, West Virginia and Ohio more than tripling since 2011. Not all of the natural gas produced in this region can be consumed by regional demand and must therefore be exported to other regions through pipelines. This export causes gas purchased and sold locally to be priced at a discount to many other market hubs, such as the benchmark Louisiana Henry Hub price. This discount, or negative basis, to the Henry Hub price is forecasted to continue in future years. While we expect many of the planned interstate pipeline projects to reduce this discount, it could widen further if these projects to move gas out of the basin are delayed or denied for any reason, such as permitting issues or environmental lawsuits.

An extended period of lower natural gas prices can negatively affect us in several other ways, including reduced cash flow, which decreases funds available for capital expenditures to replace reserves or increase production. Also, our access to other sources of capital, such as equity or long-term debt markets, could be severely limited or unavailable.

Our drilling plans also include some activity in areas of shale formations that may also contain NGLs, condensate and/or oil. The prices for NGLs, condensate and oil are also volatile for reasons similar to those described above regarding natural gas. As a result of increasing supply, condensate and oil prices have exhibited great volatility. In addition, similar to the oversupply of natural gas, increased drilling activity by third-parties in formations containing NGLs has led to a decline of over 40% since 2014 in the uplift we receive, on an Mcf equivalent basis when excluding hedging impact, from NGLs. Our results of operations may be adversely affected by a continued depressed level of, or further downward fluctuations in, NGLs, condensate and oil prices.

Apart from issues with respect to the supply of products we produce, demand can fluctuate widely due to a number of matters beyond our control, including:

- weather conditions in our markets that affect the demand for natural gas;
- changes in the consumption pattern of industrial consumers, electricity generators and residential users of electricity and natural gas;
- with respect to natural gas, the price and availability of alternative fuel sources used by electricity generators;
- technological advances affecting energy consumption and conservation measures reducing demand;
- the costs, availability and capacity of transportation infrastructure;
- proximity and capacity of natural gas pipelines and other transportation facilities;
- changes in levels of international demand and tariffs associated with international export; and

- the impact of domestic and foreign governmental laws and regulations, including environmental and climate change regulations and delays.

Our business depends on gathering, processing and transportation facilities and other midstream facilities owned by CNXM and others. The disruption of, capacity constraints in, or proximity to pipeline systems could limit sales of our natural gas and NGLs and cash flows from operations, and any decrease in availability of pipelines or other midstream facilities interconnected to third parties' or CNXM's gathering systems could adversely affect our operations or our investment in CNXM.

We gather, process and transport our natural gas to market by utilizing pipelines and facilities owned by others, including CNXM. If pipeline or facility capacity is limited, or if pipeline or facility capacity is unexpectedly disrupted for any reason, our natural gas sales and/or sales of NGLs could be reduced, which could negatively affect our profitability. If we cannot access processing pipeline transportation facilities, we may have to reduce our production of natural gas. If our sales of natural gas or NGLs are reduced because of transportation or processing constraints, our revenues will be reduced and our unit costs will increase. If pipeline quality standards change or we cannot meet applicable standards, we might be required to install additional processing equipment which could increase our costs. Further, in some circumstances we need to meet predetermined specifications with respect to our blending of dry and damp gas; changes in the production mix could negatively impact our ability to efficiently meet our specified requirements. Pipelines could also curtail our flows until the natural gas delivered to their pipeline is in compliance. Any reduction in our production of natural gas or increase in our costs could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Further, a significant portion of our natural gas is sold on or through a single pipeline, Texas Eastern Transmission, which could experience capacity issues, operational disruptions and unexpected downtime. Any reduction in capacity on the Texas Eastern pipeline could result in curtailments and reduce our production of natural gas. A reduction in capacity could also reduce the demand for our natural gas, which would reduce the price we receive for our production.

In addition to our relationship with CNXM, we have various third-party firm transportation, natural gas processing, gathering and other agreements in place, many of which have minimum volume delivery commitments. We are obligated to pay fees on minimum volumes to our service providers regardless of actual volume throughput. Reductions in our drilling program may result in insufficient production to utilize our full firm transportation and processing capacity. If we have insufficient production to meet the minimum volumes, our cash flow from operations will be reduced, which may require us to reduce or delay our planned investments and capital expenditures or seek alternative means of financing, all of which may have a material adverse effect our business, financial condition, results of operations and cash flows.

Our investment in midstream infrastructure through CNXM is intended, among other items, to connect our wells to other existing gathering and transmission pipelines. Our infrastructure development and maintenance programs, through CNXM, can involve significant risks, including those relating to timing, cost overruns and operational efficiency, which risks can be further affected by other issues. For example, approximately 34% of our 2018 production flowed through CNXM's Majorsville and McQuay Stations. An operational issue at either of those stations would materially impact CNX's production, cash flow and results of operation. CNXM's assets connect to other pipelines or facilities owned and operated by unaffiliated third parties. The continuing operation of third-party pipelines, processing and fractionation plants, compressor stations and other midstream facilities is not within our or CNXM's control. These third-party pipelines, processing and fractionation plants, compressor stations and other midstream facilities may become unavailable because of testing, turnarounds, line repair, maintenance, changes to operating conditions, delivery or receipt parameters, unavailability of firm transportation, lack of operating capacity, force majeure events, regulatory requirements and curtailments of receipt or deliveries due to insufficient capacity or because of damage from severe weather conditions or other operational issues.

We face uncertainties in estimating our economically recoverable natural gas reserves, and inaccuracies in our estimates could result in lower than expected revenues, higher than expected costs and decreased profitability.

Natural gas reserves are economically recoverable when the price at which they are expected to be sold exceeds their expected cost of production and sales. Natural gas reserves require subjective estimates of underground accumulations of natural gas, and assumptions concerning natural gas prices, production levels, reserve estimates and operating and development costs. As a result, estimated quantities of proved natural gas reserves and projections of future production rates and the timing of development expenditures may prove to be incorrect. For example, a significant amount of our proved undeveloped reserves extensions and discoveries during the last three years were due to the addition of wells on our Marcellus Shale acreage more than one offset location away from existing production with reliable technology, which may be more susceptible to positive and negative changes in reserve estimates than our proved developed reserves. Over time, material changes to reserve estimates may be made, taking into account the results of actual drilling, testing and production. Also, we make certain assumptions regarding natural gas prices, production levels, and operating and development costs that may prove to be incorrect. Any significant variance from these assumptions to actual figures could greatly affect our estimates of our natural gas reserves, the economically recoverable quantities of natural gas attributable to any particular group of properties, the classifications of natural gas reserves based on risk of recovery and estimates of the future net cash flows. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of natural gas we ultimately recover being different from reserve estimates. The PV-10 measure of pre-tax discounted future net cash flows and the standardized measure of after tax discounted future net cash flows from our proved reserves included within this Annual Report on Form 10-K are not necessarily the same as the current market value of our estimated natural gas reserves. We base the estimated discounted future net cash flows from our proved natural gas reserves on historical average prices and costs. However, actual future net cash flows from our natural gas properties also will be affected by factors such as:

- geological conditions;
- our acreage position, and our ability to acquire additional acreage, including third-party swaps to develop our position efficiently;
- changes in governmental regulations and taxation;
- the amount and timing of actual production;
- future prices and our hedging position;
- future operating costs;
- operational risks and results; and
- capital costs of drilling, completion and gathering assets.

The timing of both our production and our incurrence of expenses in connection with the development and production of natural gas properties will affect the timing of actual future net cash flows from proved reserves and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general. If natural gas prices decline by $0.10 per Mcf, then the pre-tax present value using a 10% discount rate of our proved natural gas reserves as of December 31, 2018 would decrease from $6.2 billion to $6.0 billion.

Each of the factors impacting reserve estimation may in fact vary considerably from the assumptions used in estimating the reserves. For these reasons, estimates of natural gas reserves may vary substantially. Actual production, revenues and expenditures with respect to our natural gas reserves will likely vary from estimates, and these variances may be material. As a result, our estimates may not accurately reflect our actual natural gas reserves.

Developing and producing natural gas wells is a high-risk activity.

Our growth is materially dependent upon the success of our drilling program. Drilling for natural gas and oil involves numerous risks, including the risk that an encountered well does not produce in sufficient quantities to make the well economically viable. The cost of drilling, completing and operating wells is substantial and uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors beyond our control, including those discussed in "*Our operations are subject to operating risks that could increase our operating expenses and decrease our production levels which could adversely affect our results of operations. Our operations are also subject to hazards, and any losses or liabilities, we suffer from such hazards may not be fully covered by our insurance policies*" set forth below.

Our future drilling activities may not be successful, and if they are unsuccessful, such failure will have an adverse effect on our future results of operations and financial condition. Our overall drilling success rate or our drilling success rate within a particular geographic area may decline. We may be unable to drill identified or budgeted wells within our expected time frame, or at all. We may be unable to drill a particular well because, in some cases, we identify a drilling location before we have leased all of the interests required to drill the well in that location. Similarly, our drilling schedule may vary from our capital budget. The final determination with respect to the drilling of any scheduled or budgeted wells will be dependent on a number of factors, including:

- the results of delineation efforts and the acquisition, review and analysis of seismic data;
- the availability of sufficient capital resources to us and any other participants in a well for the drilling of the well;
- whether we are able to acquire on a timely basis all of the leasehold interests required for the well, including through swap transactions with other operators;
- whether we are able to obtain, on a timely basis or at all, the permits required to drill the wells;
- whether production levels align with estimates;
- economic and industry conditions at the time of drilling, including prevailing and anticipated prices for natural gas and oil and the availability of drilling rigs and crews;

- the formation as to which we drill, as the cost structure between wet gas which requires additional processing and dry gas varies; and
- our financial resources and results.

Our business strategy focuses on horizontal drilling and production in the Marcellus and Utica Shale plays in the Appalachian Basin. Drilling horizontal wells is technologically difficult and involves risks relating to our ability to fracture stimulate the planned number of stages and to successfully run casing the length of the well bore and involves a higher risk of failure when compared to vertical wells. Additionally, drilling a horizontal well involves higher costs, which results in the risks of our drilling program being spread over a smaller number of wells, and that, in order to be profitable, each horizontal well will need to produce at a higher level in order to cover the higher drilling costs. Similarly, the average lateral length of the horizontal wells we drill has generally been increasing. Longer-lateral wells are typically more expensive and require more time for preparation and permitting. In addition, we use multi-well pads instead of single-well sites. The use of multi-well pad drilling increases some operational risks because problems affecting the pad, or a single well could adversely affect production from all of the wells on the pad. Pad drilling can also make our overall production, and therefore our revenue and cash flows, more volatile, because production from multiple wells on a pad will typically commence simultaneously. While we believe that we are better served by drilling horizontal wells using multi-well pads, the risk component involved in such drilling will be increased in some respects, with the result that we might find it more difficult to achieve economic success in our drilling program.

Our operations are subject to operating risks that could increase our operating expenses and decrease our production levels, which could adversely affect our results of operations. Our operations are also subject to hazards, and any losses or liabilities we suffer from such hazards may not be fully covered by our insurance policies.

Our exploration for and production of natural gas and CNXM’s gathering, compression and transportation operations involve numerous operational risks. The cost of drilling, completing and operating our shale gas wells, shallow oil and gas wells and coalbed methane (CBM) wells is often uncertain, and a number of factors can delay, suspend, or prevent drilling operations, decrease production and/or increase the cost of our natural gas operations at particular sites for varying lengths of time thereby adversely affecting our operating results. The risks that may have a significant impact on our natural gas operations include those relating to, among other things, unexpected drilling conditions (pressure or irregularities in geologic formations or wells, material and equipment failures, fires, ruptures, landslides, mine subsidence, explosions or other accidents and environmental concerns and adverse weather conditions); similar operational or design issues relating to pipelines, compressor stations, pump stations, related equipment and surrounding properties, including with respect to materials and equipment developed, designed or installed or properties owned or operated by third-parties; challenges relating to transportation, pipeline infrastructure and capacity for treatment or disposal of waste water generated in drilling, completion and production operations and failure to obtain, or delays in the issuance of, permits at the state or local level and the resolution of regulatory concerns.

The realization of any of these risks could adversely affect our ability to conduct our operations, materially increase our costs, or result in substantial loss to us as a result of claims for:

- personal injury or loss of life;
- damage to and destruction of property, natural resources and equipment, including our properties and our natural gas production or transportation facilities;
- pollution and other environmental damage to our properties or the properties of others;
- potential legal liability and monetary losses;
- damage to our reputation within the industry or with customers;
- regulatory investigations and penalties;

- suspension of our operations; and
- repair and remediation costs.

The occurrence of any of these events in our gas operations that prevents delivery of natural gas to a customer and is not excusable as a force majeure event under our supply agreement, could result in economic penalties, suspension or ultimately termination of the supply agreement.

Although we and CNXM maintain insurance for a number of risks and hazards, we may not be insured or fully insured against the losses or liabilities that could arise from a significant accident or disruption in our operations. We may elect not to obtain insurance for any or all of these risks if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our identified drilling locations are scheduled out over multiple years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management team has specifically identified and scheduled certain drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including natural gas and oil prices, the availability and cost of capital, drilling and production costs, the acquisition on acceptable terms of any leasehold interests we do not control but that are necessary to complete the drilling unit, including potentially through third-party swap transactions, availability of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory and zoning approvals and other factors. Because of these uncertain factors, we do not know if the numerous drilling locations we have identified will ever be drilled. We will require significant additional capital over a prolonged period in order to pursue the development of these locations, and we may not be able to raise or generate the capital required to do so. Any drilling activities we are able to conduct on these locations may not be successful or result in our ability to add additional proved reserves or may result in a downward revision of our estimated proved reserves, which could have a material adverse effect on our business and results of operations.

Strategic determinations, including the allocation of capital and other resources to strategic opportunities, are challenging, and our failure to appropriately allocate capital and resources among our strategic opportunities may adversely affect our financial condition.

Our future growth prospects are dependent upon our ability to identify optimal strategies for investing our capital resources to produce superior rates of return. In developing our business plan, we consider allocating capital and other resources to various aspects of our businesses including well development (primarily drilling), reserve acquisitions, exploratory activity, corporate items (including share and debt repurchases) and other alternatives. We also consider our likely sources of capital, including cash generated from operations and borrowings under our credit facilities. Notwithstanding the determinations made in the development of our business plan, business opportunities not previously identified periodically come to our attention, including possible acquisitions and dispositions. If we fail to identify optimal business strategies or fail to optimize our capital investment and capital raising opportunities and the use of our other resources in furtherance of our business strategies, our financial condition and future growth may be adversely affected. Moreover, economic or other circumstances may change from those contemplated by our business plan, and our failure to recognize or respond to those changes may limit our ability to achieve our objectives.

Our development and exploration projects, as well as CNXM’s midstream system development, require substantial capital expenditures and if we fail to generate sufficient cash flow or obtain required capital or financing on satisfactory terms, our natural gas reserves may decline, and financial results may suffer.

As part of our strategic determinations, we expect to continue to make substantial capital expenditures in the development and acquisition of natural gas reserves. Further, CNXM will need to make substantial capital expenditures to fund its share of growth capital expenditures associated with its Anchor Systems, as well as to fund its share of expenditures associated with its 5% controlling interests in the Additional Systems or to purchase or construct new midstream systems. If CNXM is unable to make sufficient or effective capital expenditures, it will be unable to maintain and grow its business.

CNXM's amended gathering agreement with us, CNXM's largest customer, includes minimum well commitments; however, that gas gathering agreement and the gas gathering agreements CNXM has with other third-parties impose obligations on CNXM to invest capital which is not fully protected against volumetric risks associated with lower-than-forecast volumes flowing through its gathering systems. To the extent CNXM’s customers are not contractually obligated to, and determine not to, develop their properties in the areas covered by CNXM’s acreage dedications, the resulting decreases in the development of reserves by CNXM customers could result in reduced volumes serviced by CNXM and a commensurate decline in revenues and cash flows.

There is no assurance that we or CNXM will have sufficient cash from operations, borrowing capacity under each company’s respective credit facilities or the ability to raise additional funds in the capital markets to meet our capital requirements. If cash flow generated by our operations or available borrowings under either company’s credit facilities are not sufficient to meet our capital requirements, or we are unable to obtain additional financing, we could be required to curtail the pace of the development of our natural gas properties and midstream activities, which in turn could lead to a decline in our reserves and production, and could adversely affect our business, financial condition and results of operations.

Regulation of greenhouse gas emissions at the federal or state level may increase our operating costs and reduce the value of our natural gas assets and such regulation, as well as uncertainty concerning such regulation, could adversely impact the market for natural gas, as well as for our securities.

The issue of global climate change continues to attract considerable public and scientific attention with underlying concern about the impacts of human activity, especially the emissions of greenhouse gases ("GHGs") such as carbon dioxide ("CO2") and methane, on the environment.

The EPA, under the Climate Action Plan, elected to regulate GHGs under the Clean Air Act ("CAA") to limit emissions of CO2 from natural gas-fired power plants. On August 3, 2015, the EPA finalized the Carbon Pollution Standards to cut carbon emissions from new, modified and reconstructed power plants, which became effective on October 23, 2015. In August 2015, the EPA finalized the Clean Power Plan Rule to cut carbon pollution from existing power plants, which became effective on December 22, 2015. While consolidated petitions challenging the Clean Power Plan Rule are ongoing at the circuit court level, a mid-litigation application to the Supreme Court has resulted in a current stay of the Clean Power Plan Rule. In April 2017, the EPA announced that it was initiating a review of the Clean Power Plan consistent with President Trump's Executive Order 13783, and in October 2017 published a proposed rule to formally repeal the Clean Power Plan. On August 20, 2018, the EPA issued the proposed "Affordable Clean Energy Rule." The comment period on the proposal closed on October 31, 2018, and the EPA is considering the comments submitted. On November 21, 2018, the EPA filed a status report in which the EPA indicated that it expected to take final rulemaking action on a replacement rule for the Clean Power Plan by the first part of 2019.

The EPA has adopted regulations under existing provisions of the federal Clean Air Act that establish Prevention of Significant Deterioration, or PSD, construction and Title V operating permits for large stationary sources. Facilities requiring PSD permits may also be required to meet "best available control technology" (BACT) standards. Rulemaking related to GHG could alter or delay our ability to obtain new and/or modified source permits.

The EPA has also adopted rules to control volatile organic compound emissions from certain oil and gas equipment and operations as part of its initiative to reduce methane emissions. In response to subsequent judicial involvement, the EPA issued a proposed rule in July 2017 that would stay the methane rule for two years, but this rule is not yet final and is subject to public notice, comment, and legal challenges.

Additionally, the application of the CAA to CNX and CNXM facilities, as well as the application of state sponsored permitting programs provide regulatory uncertainty and therefore present risks, including risks regarding hitting production objectives, and cost for controls and compliance. Some states in which we operate, including Pennsylvania are contemplating measures, or have issued mandates, to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and potential cap-and-trade programs. Most of these types of programs require major source of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available being reduced each year until a target goal is achieved. The cost of these allowances could increase over time. While new laws and regulations that are aimed at reducing GHG emissions will increase demand for natural gas, they may also result in increased costs for permitting, equipping, monitoring and reporting GHGs associated with natural gas production and use.

Environmental regulations can increase costs and introduce uncertainty that could adversely impact the market for natural gas with potential short and long-term liabilities.

We and CNXM are subject to various stringent federal, state and local laws and regulations relating to the discharge of materials into, and protection of, the environment. Numerous governmental authorities, such as the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly response actions. These laws and regulations may impose numerous obligations that are applicable to our, CNXM's and our respective customers' operations. Failure to comply with these laws, regulations and permits may result in joint and several or strict liability or the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, and/or the issuance of injunctions limiting or preventing some or all of our operations. Private parties, including the owners of the properties through which CNXM's gathering systems pass, may also have the right to pursue legal actions to enforce compliance, as well as to seek damages for non-compliance, with environmental laws and regulations or for personal injury or property damage. We may not be able to recover all or any of these costs from insurance. There is no assurance that changes in or additions to public policy regarding the protection of the environment will not have a significant impact on our operations and profitability.

Our operations, and those of CNXM, also pose risks of environmental liability due to leakage, migration, releases or spills from our operations to surface or subsurface soils, surface water or groundwater. Certain environmental laws impose strict as well as joint and several liability for costs required to investigate, remediate, and restore sites where hazardous substances, hydrocarbons or solid wastes have been stored or released. We may also be subject to fines and penalties for such releases. We may be required to remediate contaminated properties currently or formerly operated by us regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations.

The Federal Endangered Species Act (ESA) and similar state laws protect species endangered or threatened with extinction. Protection of endangered and threatened species may cause us to modify gas well pad siting or pipeline right of ways, or to develop and implement species-specific protection and enhancement plans and schedules to avoid or minimize impacts to endangered species or their habitats. A number of species indigenous to the areas where we operate are protected under the ESA, including the Northern Long-Earned and Indiana bats. Further consideration for listing species within our operating region is expected, and CNX considers this uncertainty, as well as the cost to comply with stringent mitigation requirements, a risk to cost and operational timing.

CNX utilizes pipelines extensively for its natural gas and water businesses. Stream encroachment and crossing permits from the Army Corps of Engineers (ACOE) are often required for certain impacts these pipelines cause to streams and wetlands. In June 2017, the EPA and the Army Corps of Engineers proposed a rule that would initiate the first step in a two-step process intended to review and revise the definition of “waters of the United States” under the Clean Water Act. The EPA moved forward with the first step on December 11, 2018, when it issued a proposed, revised rule which would replace a prior 2015 rule with pre-2015 regulations, and which narrowed language defining “waters of the United States” under the Clean Water Act that existed prior to that time. This proposal is subject to public comment and the rulemaking process. The second step would be a notice-and-comment rulemaking in which federal agencies will conduct a substantive reevaluation of such definition. While we cannot at this time predict the final form that the rule will ultimately take, such rulemaking could lead to additional mitigation costs and severely limit CNX’s operations.

Other regulations applicable to the natural gas industry are under constant review for amendment or expansion at both the federal and state levels. Any future changes may increase the costs of producing natural gas and other hydrocarbons, which would adversely impact our cash flows and results of operations. For example, hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight unconventional shale formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas agencies. The disposal of produced water and other wastes in underground injection disposal wells is regulated by the EPA under the federal Safe Drinking Water Act or by various states in which we conduct operations under counterpart state laws and regulations. The imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct hydraulic fracturing operations or to dispose of waste resulting from such operations.

We may not be able to obtain required personnel, services, equipment, parts and raw materials in a timely manner, in sufficient quantities or at reasonable costs to support our operations.

We rely on third-party contractors to provide key services and equipment for our operations. We contract with third-parties for well services, related equipment, and qualified experienced field personnel to drill wells, construct pipelines and conduct field operations. We also utilize third-party contractors to provide land acquisition and related services to support our land operational needs. The demand for these services, this equipment and for qualified and experienced field personnel to drill wells, construct pipelines and conduct field operations, geologists, geophysicists, engineers, and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with natural gas and oil prices, causing periodic shortages. Weather may also play a role with respect to the relative availability of certain materials. Historically, there have been shortages of drilling and workover rigs, pipe, compressors and other equipment as demand for rigs and equipment has increased along with the number of wells being drilled. The costs and delivery times of equipment and supplies are substantially greater in periods of peak demand, including increased demand for plays outside of our area of geographic focus. Accordingly, we cannot assure that we will be able to obtain necessary services, drilling equipment and supplies in a timely manner or on satisfactory terms, and we may experience shortages of, or increases in the costs of, drilling equipment, crews and associated supplies, equipment and field services in the future.

Any of the above shortages may lead to escalating prices for drilling equipment, land services, crews and associated supplies, equipment and services. Shortages may lead to poor service and inefficient drilling operations and increase the possibility of accidents due to the hiring of inexperienced personnel and overuse of equipment by contractors. Additionally, a decrease in the availability of these services, equipment and personnel could lead to a decrease in our natural gas production, increase our costs of natural gas production, and decrease our anticipated profitability. Such shortages could delay or cause us to incur significant expenditures that are not provided for in our capital budget, which events could materially and adversely impact our business, financial condition, results of operations, or cash flows.

We attempt to mitigate the risks involved with increased natural gas production activity by entering into “take or pay” contracts with well service providers which commit them to provide field services to us at specified levels and commit us to pay for field services at specified levels even if we do not use those services. However, these types of contracts expose us to economic risk during a downturn in demand or during periods of oversupply. For example, in the year ended December 31, 2018 and 2017, due to the oversupply of gas in our markets, we made payments under these types of contracts of approximately $7 million and $40 million, respectively, for field services that we did not use. Having to pay for services we do not use decreases our cash flow and increases our costs.

If natural gas prices decrease or drilling efforts are unsuccessful, we may be required to record write-downs of our proved natural gas properties. Additionally, changes in assumptions impacting management’s estimates of future financial results as well as other assumptions related to the Company's stock price, weighted-average cost of capital, terminal growth rates and industry multiples, could cause goodwill and other intangible assets we hold to become impaired and result in material non-cash charges to earnings.

Lower natural gas prices or wells that produce less than expected quantities of natural gas may reduce the amount of natural gas that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs, or if our estimates of development costs increase, production data factors change or our exploration results deteriorate, accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our natural gas properties. We are required to perform impairment tests on our assets whenever events or changes in circumstances lead to a reduction of the estimated useful life or estimated future cash flows that would indicate that the carrying amount may not be recoverable or whenever management's plans change with respect to those assets. For example, in the second quarter of 2015, we had an impairment charge of approximately $829 million for certain of our natural gas assets, primarily shallow oil and gas assets. We may incur impairment charges in the future, which could have an adverse effect on our results of operations in the period taken.

As a result of our acquisition of the 50% interest in CNX Gathering in the first quarter of 2018, we acquired approximately $925 million of goodwill and other intangible assets. Future acquisitions may also lead to the acquisition of additional goodwill or other intangible assets. At least annually, or whenever events or changes in circumstances indicate a potential impairment in the carrying value as defined by GAAP, we will evaluate this goodwill and other intangible assets for impairment by first assessing qualitative factors to determine whether the existence of events or circumstances leads to a determination that it is more likely than not that the fair value of the reporting unit is less than the carrying amount. Estimated fair values could change if, for example, there are changes in the business climate, unanticipated changes in the competitive environment, adverse legal or regulatory actions or developments, changes in capital structure, cost of debt, interest rates, capital expenditure levels, operating cash flows, or market capitalization. The future impairment of these assets could require material non-cash charges to our results of operations, which could have a material adverse effect on our reported earnings and results of operations for the affected periods. In May 2018, CNX determined that the carrying value of a portion of the customer relationship intangible assets that were acquired in connection with the Midstream Acquisition exceeded their fair value in conjunction with the Asset Exchange Agreement with HG Energy II Appalachia, LLC (See Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion). CNX recognized an impairment on this intangible asset of $19 million, which is included in Impairment of Other Intangible Assets in the Consolidated Statements of Income.

Competition and consolidation within the natural gas industry may adversely affect our ability to sell our products and midstream services. Increased competition or a loss of our competitive position could adversely affect our sales of, or our prices for, our products, which could impair our profitability.

The natural gas, exploration, production and midstream industries are intensely competitive with companies from various regions of the United States and, increasingly, competition in the international markets. The industry has been experiencing increased competitive pressures as a result of both consolidation within the exploration and production space, along with the emergence of stand-alone midstream companies. Many of the companies with which we and CNXM compete are larger and have greater financial, technological, human and other resources. If we are unable to compete, our company, our operating results and financial position may be adversely affected. In addition, larger companies may be able to pay more to acquire new natural gas properties for future exploration, limiting our ability to replace the natural gas we produce or to grow our production. There is also increased competition within the industry as a result of oil-focused drilling, where natural gas is produced as an ancillary byproduct and may be sold at prices below market. The highly competitive environment in which we operate may negatively impact our ability to acquire additional properties at prices or upon terms we view as favorable. The competitive environment can also make it more challenging to discover new natural gas resources, evaluate and select suitable properties and to consummate these transactions on acceptable terms. Any reduction in our ability to compete in current or future natural gas markets could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Additionally, CNXM's ability to increase throughput on its midstream systems and any related revenue from third-parties is subject to capacity availability on its existing systems, its ability to expand its existing systems, contractual obligations to its existing customers and competition from third parties, primarily operators of other natural gas gathering systems. The fact that a substantial majority of the capacity of CNXM's midstream systems will be necessary to service the production of CNX and one third-party customer and we and that third-party will receive priority of service for the provision of CNXM midstream services over other third-parties, may result in CNXM not having the capacity to provide services to other third-party customers. In addition, potential third-party customers who are significant producers of natural gas and condensate may develop their own midstream systems in lieu of using CNXM's systems. All of these competitive pressures could have a material adverse effect on CNXM's business, results of operations, financial condition, cash flows and ability to make cash distributions and therefore, could have a material adverse effect on our investment in CNXM.

Deterioration in the economic conditions in any of the industries in which our customers operate, a domestic or worldwide financial downturn, or negative credit market conditions may have a material adverse effect on our liquidity, results of operations, business and financial condition that we cannot predict.

Economic conditions in a number of industries in which our customers operate, such as electric power generation, have experienced substantial deterioration in the past, resulting in reduced demand for natural gas. In addition, liquidity is essential to our business and developing our assets. Renewed or continued weakness in the economic conditions of any of the industries we serve or that are served by our customers could adversely affect our business, financial condition, results of operation and liquidity in a number of ways. For example:

- demand for natural gas and electricity in the United States is impacted by industrial production, which if weakened would negatively impact the revenues, margins and profitability of our natural gas business;
- the tightening of credit or lack of credit availability to our customers could adversely affect us, as our ability to receive payment for natural gas sold and delivered depends on the continued creditworthiness of our customers;
- our ability to access the capital markets may be restricted at a time when we would like, or need, to raise capital for our business including for exploration and/or development of our natural gas reserves; and
- a decline in our creditworthiness may require us to post letters of credit, cash collateral, or surety bonds to secure certain obligations, all of which would have an adverse effect on our liquidity.

Our hedging activities may prevent us from benefiting from price increases and may expose us to other risks.

To manage our exposure to fluctuations in the price of natural gas, we enter into hedging arrangements with respect to a portion of our expected production. As of January 18, 2019, we expect these transactions will represent approximately 376.0 Bcf of our estimated 2019 production at an average price of $2.71 per Mcf, 468.6 Bcf of our estimated 2020 production at an average price of $2.55 per Mcf, 410.3 Bcf of our estimated 2021 production at an average price of $2.44 per Mcf, 276.6 Bcf of our estimated 2022 production at an average price of $2.48 per Mcf, and 127.0 Bcf of our estimated 2023 production at an average price of $2.35 per Mcf. To the extent that we engage in hedging activities, we may be prevented from realizing the near-term benefits of price increases above the levels of the hedges. If we choose not to engage in hedging arrangements in the future, reduce our future use of hedging arrangements or are unable to engage in hedging arrangements due to lack of acceptable counterparties, we may be more adversely affected by changes in natural gas prices than our competitors who engage in hedging arrangements to a greater extent than we do. Increases or decreases in forward market prices could result in material unrealized (non-cash) losses or gains on commodity derivative instruments resulting in volatility in reported earnings.

In addition, such transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected;
- we are unable to find available counterparties in the future with which to enter into hedges and counterparties able to enter into basis hedge contracts;
- the creditworthiness of our counterparties or their guarantors is substantially impaired; and
- counterparties have credit limits that may constrain our ability to hedge additional volumes.

Existing and future governmental laws, regulations and other legal requirements and judicial decisions that govern our business may increase our costs of doing business and may restrict our operations.

There are numerous governmental regulations applicable to the natural gas industry that are not directly related to environmental regulation, many of which are under constant review for amendment or expansion at the federal and state level. Any future modifications in such regulations, changes promulgated by the courts, or interruptions experienced in the operation of our governing bodies, may affect, among other things, our ability to develop the resource, obtain permits, as well as, potential impacts to the pricing or marketing of natural gas production.

For example, currently CNXM’s gathering operations are exempt from regulation by the Federal Energy Regulatory Commission (FERC) under the Natural Gas Act (NGA). Although FERC has not made any formal determinations with respect to any of CNXM’s facilities considered to be gathering facilities, CNXM believes that the natural gas pipelines in its gathering systems meet the traditional tests FERC has used to establish that a natural gas pipeline is a gathering pipeline not subject to FERC jurisdiction. However, this issue has been the subject of substantial litigation, and if FERC were to consider the status of an individual facility and determine that the facility or services provided by it are not exempt from FERC regulation under the NGA, the rates for, and terms and conditions of, services provided by such facility would become subject to regulation by FERC. Such regulation could decrease revenue, increase operating costs, and, depending upon the facility in question, could adversely affect results of operations and cash flows for CNXM.

Additionally, some states have begun to adopt more stringent regulation and oversight of natural gas gathering lines than is currently required by federal standards. Pennsylvania, under Act 127, authorized Public Utility Commission (PUC) oversight of Class I gathering lines, and required standards and fees for Class II and Class III pipelines. The State of Ohio also moved to regulate natural gas gathering lines in a similar manner pursuant to Ohio Senate Bill 315 (SB315). SB315 expanded the Ohio PUC's authority over rural natural gas gathering lines. These changes in interpretation and regulation affect midstream activities of CNXM and other third-party providers with whom we interact, requiring changes in reporting, as well as increased costs.

Various judicial decisions that may directly or indirectly impact natural gas drilling could also serve to increase our cost of doing business or restrict our operations. For example, a recent Pennsylvania case currently on appeal involves concepts of landowner rights, trespass claims and the historic common law concept of “rule of capture.” Although the case has not yet been resolved, the ultimate judicial outcome could negatively impact future shale drilling and hydraulic fracturing within the Commonwealth of Pennsylvania if the court finds that fracking could be considered trespassing in certain circumstances.

We may incur significant costs and liabilities as a result of pipeline operations and related increase in the regulation of gas gathering pipelines.

Pipeline and Hazardous Materials Safety Administration (PHMSA) has adopted regulations requiring pipeline operators to develop integrity management programs for transportation pipelines and related facilities located where a leak or rupture could do the most harm, i.e., in “high consequence areas.” The regulations require operators to:

- perform ongoing assessments of pipeline and related facility integrity;
- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;
- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventive and mitigating actions.

Should our or CNXM's operations fail to comply with PHMSA or comparable state regulations, we could be subject to substantial penalties and fines, including civil penalties of up to $209,000 per violation, with a maximum of $2,909,022 for those related series of violations. In January 2017, PHMSA released a pre-publication copy of its final hazardous liquid pipeline safety regulations that would significantly extend the integrity management requirements to previously exempt pipelines and would impose additional obligations on hazardous liquid pipeline operators that are already subject to the integrity management requirements. However, due to the change in Presidential administrations, PHMSA’s final hazardous liquid pipeline safety rule has not yet taken effect, though PHMSA is expected to finalize its hazardous liquid pipeline safety in the near term. PHMSA’s proposed rule would also require annual reporting of safety-related conditions and incident reports for all hazardous liquid gathering lines and gravity lines, including pipelines exempt from PHMSA regulations.

PHMSA also issued a separate regulatory proposal in July 2015 that would impose pipeline incident prevention and response measures on natural gas and hazardous liquid pipeline operators and in April 2016, published a Notice of Proposed Rule making that would significantly modify existing regulations related to reporting, impact, design, construction, maintenance, operations and integrity management of gas transmission and gathering pipelines. As proposed, compliance with the rule could have a material adverse effect on our or CNXM's operations. However, the ultimate impact of the rule on our and CNXM remains uncertain until the rulemaking is finalized. The adoption of these regulations, which apply more comprehensive or stringent safety standards than we are currently subject to, could require us to install new or modified safety controls, pursue new capital projects, or conduct maintenance programs on an accelerated basis, all of which could require us to incur increased operational costs that could be significant. While we cannot predict the outcome of legislative or regulatory initiatives, such legislative and regulatory changes could have a material effect on our cash flow.

Our shale gas drilling and production operations require both adequate sources of water to use in the fracturing process, as well as the ability to dispose of, transport or recycle the water after hydraulic fracturing. Our CBM gas drilling and production operations also require the removal and disposal of water from the coal seams from which we produce gas. If we cannot find adequate sources of water for our use or we are unable to dispose of or recycle the water at a reasonable cost and within applicable environmental rules, our ability to produce natural gas economically and in sufficient quantities could be impaired.

As part of our drilling and production in shale formations, we use hydraulic fracturing processes. These processes require access to adequate sources of water, which may not be available in proximity to our operations or at certain times of the year. To ensure that we have adequate water available for our operations, we may be required to invest substantial amounts of capital in water pipelines which are used for relatively short periods of time. Increased regulation of these water pipelines could cause us to invest additional capital, alter our disposal or transportation method or affect our operations in other manners. Alternatively, we may be required to truck water, and we may not be able to contract for sufficient water hauling trucks to meet our needs.

Further, we must remove the portion of the water that flows back to the well bore, as well as drilling fluids and other wastes associated with the exploration, development or production of natural gas. This water can be either disposed of or recycled for use in other hydraulic fracturing operations. In the event we are forced to dispose of water rather than recycle it, our costs may increase. In addition, in our CBM drilling and production, coal seams frequently contain water that must be removed and disposed of in order for the natural gas to detach from the coal and flow to the well bore.

Our inability to obtain sufficient amounts of water with respect to our shale operations, or the inability to dispose of or recycle water and other wastes used in our shale and our CBM operations in an economically efficient manner, could increase our costs and delay our operations, which will adversely impact our cash flow and results of operations.

Failure to find or acquire economically recoverable natural gas reserves to replace our current natural gas reserves will cause our levels of natural gas reserves and production to decline, which would adversely affect our business, financial condition, results of operations, liquidity and cash flows.

Producing natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Because total estimated proved reserves include our proved undeveloped reserves at December 31, 2018, production is expected to decline even if those proved undeveloped reserves are developed and the wells produce as expected. The rate of decline will change if production from our existing wells declines in a different manner than we have estimated and can change under other circumstances. Thus, our future natural gas reserves and production and, therefore, our cash flow and income are highly dependent on our success in efficiently developing, exploiting and selling our current reserves and economically finding or acquiring additional economically recoverable reserves. We may not be able to develop, find or acquire additional economically recoverable reserves to replace our current and future production at acceptable costs.

In addition, the level of natural gas and condensate volumes handled through the CNXM midstream systems depends on the level of production from natural gas wells dedicated to such midstream systems, which may be less than expected and which will naturally decline over time. In order to maintain or increase throughput levels on CNXM's midstream systems, CNXM must obtain production from new wells completed by us and any third-party customers on acreage dedicated to the CNXM midstream systems or execute agreements with other third-parties in CNXM's areas of operation. CNXM has no control over producers' levels of development and completion activity in its areas of operations, the amount of reserves associated with wells connected to CNXM's systems or the rate at which production from a well declines.

The provisions of our debt agreements and those of CNXM, and the risks associated therewith could adversely affect our business, financial condition, liquidity and results of operations.

As of December 31, 2018, CNX's total long-term indebtedness, excluding CNXM, was approximately $1.9 billion of which approximately (i) $1.3 billion was under our 5.875% senior unsecured notes due 2022 plus $2.1 million of unamortized bond premium, (ii) $612.0 million was under our senior secured credit facility and (iii) $13.3 million of capitalized leases due through 2021. The degree to which we are leveraged could have important consequences, including, but not limited to:

- increasing our vulnerability to general adverse economic and industry conditions;
- requiring us to dedicate a substantial portion of our cash flow from operations to the payment of interest and principal due under our outstanding debt, which will limit our ability to obtain additional financing to fund future working capital, capital expenditures, acquisitions, development of our natural gas reserves or other general corporate requirements;
- limiting our flexibility in planning for, or reacting to, changes in our business and in the natural gas industry;

- placing us at a competitive disadvantage compared to our competitors with lower leverage and better access to capital resources; and
- limiting our ability to implement our business strategy.

Further, LIBOR and certain other interest rate "benchmarks" are the subject of recent national, international, and other regulatory guidance and proposals for reform. These reforms may cause such benchmarks to perform differently than in the past or have other consequences which cannot be predicted. On July 27, 2017, the United Kingdom's Financial Conduct Authority, which regulates LIBOR, publicly announced that it intends to stop persuading or compelling banks to submit LIBOR rates after 2021. It is expected that a transition away from the widespread use of LIBOR to alternative rates will occur over the course of the next several years. As a result of this transition, LIBOR may disappear entirely or perform differently than in the past, and interest rates on our variable rate indebtedness and other financial instruments tied to LIBOR rates, as well as the revenue and expenses associated with those financial instruments, may be adversely affected.

Our senior secured credit facility and the indentures governing our 5.875% senior unsecured notes limit the incurrence of additional indebtedness unless specified tests or exceptions are met. In addition, our senior secured credit agreement and the indentures governing our 5.875% senior unsecured notes subject us to financial and/or other restrictive covenants. Under our senior secured credit agreement, we must comply with certain financial covenants on a quarterly basis including a maximum net leverage ratio and a minimum current ratio, as defined therein. Our senior secured credit agreement and the indentures governing our 5.875% senior unsecured notes impose a number of restrictions upon us, such as restrictions on granting liens on our assets, making investments, paying dividends, stock repurchases, selling assets and engaging in acquisitions. Failure by us to comply with these covenants could result in an event of default that, if not cured or waived, could have a material adverse effect on us. Further, CNXM's existing $600 million revolving credit facility and CNXM's $400 million of 6.50% senior notes, neither of which are guaranteed by CNX, subjects CNXM to certain financial and/or other restrictive covenants and other restrictions similar to those in our senior secured credit agreement and indentures.

If our or CNXM's cash flows and capital resources are insufficient to fund our respective debt service obligations, including repayment of such obligations at maturity, we or CNXM, as the case may be, may be forced to sell assets, seek additional capital or seek to restructure or refinance our indebtedness. These alternative measures may not be successful and may not permit us to meet our respective scheduled debt service obligations. In the absence of such operating results and resources, we could face substantial liquidity problems and might be required to sell material assets or operations to attempt to meet our debt service and other obligations. Our senior secured credit agreement and the indentures governing our 5.875% senior unsecured notes restrict our ability to sell assets and the use of the proceeds from the sales. We may not be able to consummate those sales or to obtain the proceeds which we could realize from them and these proceeds may not be adequate to meet any debt service obligations then due.

Our lenders use the loan value of our proved natural gas reserves to determine the borrowing base under our $2.1 billion senior secured credit facility. Our borrowing base could decrease for a variety of reasons including lower natural gas prices, declines in natural gas proved reserves, asset sales and lending requirements or regulations. Significant reductions in our borrowing base below $2.1 billion could have a material adverse effect on our results of operations, financial condition and liquidity.

Our ability to borrow and have letters of credit issued under our $2.1 billion senior secured credit facility is generally limited to a borrowing base. Our borrowing base is determined by the required number of lenders in good faith calculating a loan value of the Company's proved natural gas reserves. The borrowing base under our senior secured credit facility is currently $2.1 billion. Our borrowing base is redetermined by the lenders twice per year, and the next scheduled borrowing base redetermination is expected to occur in the Spring of 2019. The various matters which we describe in other risk factors that can decrease our proved natural gas reserves including lower natural gas prices, operating difficulties, and failure to replace our proved reserves could also decrease our borrowing base. Please read: “Risk Factors - *We face uncertainties in estimating our economically recoverable natural gas reserves, and inaccuracies in our estimates could result in lower than expected revenues, higher than expected costs and decreased profitability”* and - *“Unless we replace our natural gas reserves, our natural gas reserves and production will decline, which would adversely affect our business, financial condition, results of operations and cash flows.”* Our borrowing base could also decrease as a result of new lending requirements or regulations or the issuance of new indebtedness. If our borrowing base declined significantly below $2.1 billion, we may be unable to implement our drilling and development plans, make acquisitions or otherwise carry out our business plan which could have a material adverse effect on our financial condition and results of operations. We also could be required to repay any outstanding indebtedness in excess of the redetermined borrowing base. We could face substantial liquidity problems, might not be able to access the equity or debt capital markets and might be required to sell material assets or operations to attempt to meet our debt service and other obligations. We may not be able to consummate those sales or to obtain the proceeds which we could realize from them and those proceeds may not be adequate to meet any debt service obligations then due.

Changes in federal or state income tax laws could cause our financial position and profitability to deteriorate.

The passage of legislation or any other changes in U.S. federal income tax law could eliminate or postpone certain tax deductions that are currently available with respect to natural gas exploration and development. Any such change could negatively affect our financial condition and results of operations. For instance, recent tax law changes effective as of the beginning of 2018 will limit the ability of corporations to take certain interest deductions and have eliminated a corporation's ability to take deductions for income attributable to domestic production activities.

Additionally, legislation has been proposed from time to time in the states in which we operate - primarily Pennsylvania, Ohio and West Virginia - that would impose additional taxes or increase taxes on the production from our wells. The proposed tax rates have varied but would represent a greater financial burden on the economics of the wells we drill in these states.

Cyber-incidents could have a material adverse effect on our business, financial condition or results of operations.

Cyber-incidents, including cyber-attacks, may significantly affect us or the operations of our customers and business partners, as well as impact general economic conditions, consumer confidence and spending and market liquidity. Strategic targets, including energy-related assets, may be at greater risk of future incidents than other targets in the United States. A cyber incident could result in information theft, data corruption, operational disruption including environmental and safety issues resulting from a loss of control of field equipment and assets, 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, monitor and control our field equipment and assets, 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-incident 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. SCADA (supervisory control and data acquisition) based systems are potentially vulnerable to targeted cyber-attacks due to their critical role in operations.

Our technologies, systems, networks, data centers and those of our business partners may become the target of cyber-incidents 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, damage to our reputation, other operational disruptions and third-party liability, including the following:

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- a cyber-incident impacting one of our vendors or service providers could result in supply chain disruptions, loss or corruption of our information or other negative consequences, any of which could delay or halt development of additional infrastructure, effectively delaying the start of cash flows from the project;
- a cyber-incident related to our facilities may result in equipment damage or failure;
- a cyber-incident impacting midstream or downstream pipelines could prevent our product from being delivered, resulting in a loss of revenues;
- a cyber-incident impacting a communications network or power grid could cause operational disruption resulting in loss of revenues;
- a 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.

Our implementation of various internal and externally-facing controls and processes, including appropriate internal risk assessment and internal policy implementation, globally incorporating a risk-based cyber security framework to monitor and mitigate security threats and other strategies 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 or other cyber-incidents 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.

Construction of new gathering, compression, dehydration, treating or other midstream assets by CNXM may not result in revenue increases and may be subject to regulatory, environmental, political, legal and economic risks, which could adversely affect CNXM's cash flows, results of operations and our financial condition.

The construction of additions or modifications to CNXM's existing systems involves numerous regulatory, environmental, political and legal uncertainties beyond its control and may require the expenditure of significant amounts of capital. Financing may not be available on economically acceptable terms or at all. If these projects are undertaken, they may not be completed on schedule, at the budgeted cost or at all.

Revenues may not increase immediately (or at all) upon the expenditure of funds on a particular project. For instance, if a processing facility is built, the construction may occur over an extended period of time, and CNXM may not receive any material increases in revenues until the project is completed. Additionally, facilities may be constructed to capture anticipated future production growth in an area in which such growth does not materialize. As a result, new gathering, compression, dehydration, treating or other midstream assets may not be able to attract enough throughput to achieve the expected investment return, which could adversely affect CNXM's business, financial condition, results of operations, cash flows and ability to make cash distributions.

The construction of additions to CNXM's existing assets may require it to obtain new rights-of-way prior to constructing new pipelines or facilities, which may not be obtained in a timely fashion or in a way that allows CNXM to connect new natural gas supplies to existing gathering pipelines or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive to obtain new rights-of-way or to expand or renew existing rights-of-way. If the cost of renewing or obtaining new rights-of-way increases, cash flows could be adversely affected.

Our success depends on key members of our management and our ability to attract and retain experienced technical and other professional personnel.

Our future success depends to a large extent on the services of our key employees. The loss of one or more of these individuals could have a material adverse effect on our business. Furthermore, competition for experienced technical and other professional personnel remains strong. If we cannot retain our current personnel or attract additional experienced personnel, our ability to compete could be adversely affected. Also, the loss of experienced personnel could lead to a loss of technical expertise.

Terrorist activities could materially and adversely affect our business and results of operations.

Terrorist attacks, including eco-terrorism, and the threat of terrorist attacks, whether domestic or foreign, as well as military or other actions taken in response to these acts, could affect the energy industry, the environment and industry related economic conditions, including our operations and the operations of our customers, as well as general economic conditions, consumer confidence and spending and market liquidity. Strategic targets, including energy-related assets, may be at greater risk of future attacks than other targets in the United States. The occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy in unpredictable ways, including the disruption of energy supplies and markets, increased volatility in commodity prices or the possibility that the infrastructure on which we rely could be a direct target or an indirect casualty of an act of terrorism, and, in turn, could materially and adversely affect our business and results of operations. Our insurance may not protect us against such occurrences.

We may operate a portion of our business with one or more joint venture partners or in circumstances where we are not the operator, which may restrict our operational and corporate flexibility; actions taken by the other partner or third-party operator may materially impact our financial position and results of operations; and we may not realize the benefits we expect to realize from a joint venture.

As is common in the natural gas industry, we may operate one or more of our properties with a joint venture partner, or contract with a third-party to control operations. These relationships could require us to share operational and other control, such that we may no longer have the flexibility to control completely the development of these properties. If we do not timely meet our financial commitments in such circumstances, our rights to participate may be adversely affected. If a joint venture partner is unable or fails to pay its portion of development costs or if a third-party operator does not operate in accordance with our expectations, our costs of operations could be increased. We could also incur liability as a result of actions taken by a joint venture partner or third-party operator. Disputes between us and the other party may result in litigation or arbitration that would increase our expenses, delay or terminate projects and distract our officers and directors from focusing their time and effort on our business.

We do not completely control the timing of divestitures that we plan to engage in and they may not provide anticipated benefits. Additionally, we may be unable to acquire additional properties in the future and any acquired properties may not provide the anticipated benefits.

Our business and financing plans include divesting certain assets over time. However, we do not completely control the timing of divestitures, and delays in completing divestitures may reduce the benefits we may receive from them, such as elimination of management distraction by selling non-core assets and the receipt of cash proceeds that contribute to our liquidity. Additionally, if assets are held jointly with another party, we may not be permitted to dispose of these assets without the consent of our joint venture partner. Also, there can be no assurance that the assets we divest will produce anticipated proceeds. In addition, the terms of divestitures may cause a substantial portion of the benefits we anticipate receiving from them to be subject to future matters that we do not control.

In the future we may make acquisitions of assets or businesses that complement or expand our current business. No assurance can be given that we will be able to identify suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire the identified targets. The success of any completed acquisition will depend on our ability to effectively integrate the acquired business into our existing operations and to identify and appropriately manage any liabilities assumed as part of the acquisition. The process of integrating acquired businesses or assets may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. Our failure to make acquisitions in the future and successfully integrate the acquired businesses or assets into our existing operations could have a material adverse effect on our financial condition and results of operations.

CNX and its subsidiaries are subject to various legal proceedings, which may have an adverse effect on our business.

We are party to a number of legal proceedings in the normal course of business activities. Defending these actions, especially purported class actions, can be costly, and can distract management. For example, we are a defendant in pending purported class action lawsuits dealing with claimants’ alleged entitlements to, and accounting for, natural gas royalties. There is also the possibility that we may become involved in future suits, including, for example, those being brought by communities against fossil fuel producers relating to climate change, which are beginning to gain prevalence in the courts. There is the potential that the costs of defending litigation in an individual matter or the aggregation of many matters could have an adverse effect on our cash flows, results of operations or financial position. See Note 18- Commitments and Contingent Liabilities in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion of pending legal proceedings.

There is no guarantee that we will continue to repurchase shares of our common stock under our current or any future share repurchase program at levels undertaken previously or at all. Any determinations to repurchase shares of our common stock will be at the discretion of our board of directors based upon a review of all relevant considerations.

We previously announced a one-year $200 million share repurchase program that was authorized by our board of directors in September 2017, amended to increase the program to $450 million on October 30, 2017 and extended on July 30, 2018 to December 31, 2018. On October 26, 2018, our board of directors approved an additional $300 million share repurchase authorization, which is not subject to an expiration date. The repurchase program does not require us to acquire any specific number of shares. Our board of director's determination to repurchase shares of our common stock will depend upon market conditions, applicable legal requirements, contractual obligations and other factors that the board of directors deems relevant. Based on an evaluation of these factors, our board of directors may determine not to repurchase shares or to repurchase shares at reduced levels from those anticipated by our shareholders.

Negative public perception regarding our industry could have an adverse effect on our operations.

Negative public perception regarding our industry resulting from, among other things, operational incidents or concerns raised by advocacy groups about hydraulic fracturing, emissions and pipeline projects, could result in increased regulatory scrutiny, which could then result in additional laws, regulations, guidelines and enforcement interpretations, at the federal or state level. These actions may cause operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risk of litigation. Moreover, governmental authorities exercise considerable discretion in the timing and scope of permit issuance and the public may engage in the permitting process, including through intervention in the courts. Negative public perception could cause the permits we need to conduct our operations to be withheld, delayed, or burdened by requirements that restrict our ability to profitably conduct our business.

In connection with the separation, CONSOL Energy has agreed to indemnify us for certain liabilities and we have agreed to indemnify CONSOL Energy for certain liabilities. If we are required to pay under these indemnities to CONSOL Energy, our financial results could be negatively impacted. The CONSOL Energy indemnity may not be sufficient to hold us harmless from the full amount of liabilities for which CONSOL Energy has been allocated responsibility, and CONSOL Energy may not be able to satisfy its indemnification obligations in the future.

Pursuant to the Separation and Distribution Agreement and certain other agreements with CONSOL Energy, CONSOL Energy has agreed to indemnify us for certain liabilities, and we have agreed to indemnify CONSOL Energy for certain liabilities, in each case for uncapped amounts. More specifically, CONSOL Energy assumed all liabilities related to their current and our former coal business, including liabilities having a book value of $955 million and liabilities that may arise due to the failure of purchasers of coal assets that we had previously disposed. Additionally, we remain liable as a guarantor on certain liabilities that were assumed by CONSOL Energy in connection with the separation. The estimated value of these guarantees was approximately $192 million at the time of the separation. Although CONSOL Energy agreed to indemnify us to the extent that we are called upon to pay any of these liabilities, there is no assurance that CONSOL Energy will satisfy its obligations to indemnify us in these situations. For example, we could be liable for liabilities assumed by Murray Energy and its subsidiaries (Murray Energy) in connection with the disposition of certain mines to Murray Energy in 2013 in the event that both Murray Energy and CONSOL Energy are unable to satisfy those liabilities.

Indemnities that we may be required to provide CONSOL Energy are not subject to any cap, may be significant and could negatively impact our business. Third-parties could also seek to hold us responsible for any of the liabilities that CONSOL Energy has agreed to retain. Any amounts we are required to pay pursuant to these indemnification obligations and other liabilities could require us to divert cash that would otherwise have been used in furtherance of our operating business. Further, the indemnity from CONSOL Energy may not be sufficient to protect us against the full amount of such liabilities, and CONSOL Energy may not be able to fully satisfy its indemnification obligations. Moreover, even if we ultimately succeed in recovering from CONSOL Energy any amounts for which we are held liable, we may be temporarily required to bear such losses. Each of these risks could negatively affect our business, results of operations and financial condition.

The separation of CONSOL Energy could result in substantial tax liability.

Under current U.S. federal income tax law, even if the distribution, together with certain related transactions, otherwise qualifies for tax-free treatment under Sections 355 and 368(a)(1)(D) of the Internal Revenue Code, the distribution may nevertheless be rendered taxable to us and our shareholders as a result of certain post-distribution transactions, including certain acquisitions of shares or assets of CNX or CONSOL Energy. The possibility of rendering the distribution taxable as a result of such transactions may limit our ability to pursue certain equity issuances, strategic transactions or other transactions that would otherwise maximize the value of our business. Under the Tax Matters Agreement that we entered into with CONSOL Energy, CONSOL Energy may be required to indemnify us against any additional taxes and related amounts resulting from (i) an acquisition of all or a portion of the equity securities or assets of CONSOL Energy, whether by merger or otherwise (and regardless of whether CONSOL Energy participated in or otherwise facilitated the acquisition), (ii) issuing equity securities beyond certain thresholds, (iii) repurchasing shares of CONSOL Energy stock other than in certain open-market transactions, (iv) ceasing to actively conduct certain of its businesses, (v) other actions or failures to act by CONSOL Energy or (vi) any of CONSOL Energy’s representations, covenants or undertakings contained in any of the separation-related agreements and documents or in any documents relating to the IRS private letter ruling and/or the opinions of tax advisors being incorrect or violated. However, the indemnity from CONSOL Energy may not be sufficient to protect us against the full amount of such additional taxes or related liabilities, and CONSOL Energy may not be able to fully satisfy its indemnification obligations. Moreover, even if we ultimately succeed in recovering from CONSOL Energy any amounts for which we are held liable, we may be temporarily required to bear such losses. Each of these risks could negatively affect CNX’s business, results of operations and financial condition.

ITEM 1B. Unresolved Staff Comments

None.

ITEM 2. Properties

See Detail Operations in Item 1 of this 10-K for a description of CNX's properties.

ITEM 3. Legal Proceedings

Note 22–Commitments and Contingent Liabilities in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K is incorporated herein by reference.

ITEM 4. Mine Safety and Health Administration Safety Data

Not applicable.

PART II

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

The Company's common stock is listed on the New York Stock Exchange under the symbol CNX.

As of December 31, 2018, there were 116 holders of record of our common stock.

The following performance graph compares the yearly percentage change in the cumulative total shareholder return on the common stock of CNX to the cumulative shareholder return for the same period of a peer group and the Standard & Poor's 500 Stock Index. The current peer group is comprised of CNX, Antero Resources Corporation, Cabot Oil & Gas Corporation, Chesapeake Energy Corporation, Energen Corporation, EQT Corporation, Gulfport Energy Corporation, PDC Energy, Inc., Range Resources Corporation, SM Energy Company, Southwestern Energy Co., Whiting Petroleum Corporation, and WPX Energy, Inc. The graph assumes that the value of the investment in CNX common stock and each index was $100 at December 31, 2013. The graph also assumes that all dividends were reinvested and that the investments were held through December 31, 2018.

	2013	**2014**	**2015**	**2016**	**2017**	**2018**
CNX Resources Corporation	100.0	107.4	25.7	59.3	55.0	42.9
Peer Group	100.0	88.3	38.8	53.1	42.3	27.6
S&P 500 Stock Index	100.0	144.4	143.4	157.0	187.4	175.8

Cumulative Total Shareholder Return Among CNX Resources Corporation, Peer Group and S&P 500 Stock Index

The above information is being furnished pursuant to Regulation S-K, Item 201 (e) (Performance Graph).

The declaration and payment of dividends by CNX is subject to the discretion of CNX's Board of Directors, and no assurance can be given that CNX will pay dividends in the future. CNX suspended its quarterly dividend in March 2016 to further reflect the Company's increased emphasis on growth. CNX's Board of Directors determines whether dividends will be paid quarterly. The determination to pay dividends will depend upon, among other things, general business conditions, CNX's financial results, contractual and legal restrictions regarding the payment of dividends by CNX, planned investments by CNX and such other factors as the Board of Directors deems relevant. The Company's credit facility limits CNX's ability to pay dividends in excess of an annual rate of $0.50 per share when the Company's leverage ratio exceeds 3.50 to 1.00 and subject to an aggregate amount up to a cumulative credit calculation set forth in the facility. The total leverage ratio was 2.26 to 1.00 at December 31, 2018. The credit facility does not permit dividend payments in the event of default. The indentures to the 2022 notes limit dividends to $0.50 per share annually unless several conditions are met. These conditions include no defaults, ability to incur additional debt and other payment limitations under the indentures. There were no defaults in the year ended December 31, 2018.

Unregistered Sales of Equity Securities and Use of Proceeds

The following table sets forth repurchases of our common stock during the three months ended December 31, 2018:

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares Purchased (1)	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (2)	(d) Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (000's omitted)
October 1, 2018-October 31, 2018	3,552,158	$ 14.06	3,552,158	$300,643
November 1, 2018-November 30, 2018	712,300	$ 14.10	712,300	$290,597
December 1, 2018-December 31, 2018	2,230,834	$ 12.06	2,230,834	$263,684
Total	6,495,292		6,495,292	$854,924,000

(1) Includes shares withheld from employees to satisfy minimum tax withholding obligations associated with the vesting of restricted stock during the period.

(2) Shares repurchased as part of the Company's previously announced one-year $450 million share repurchase program authorized by the Board of Directors in September 2017, as amended on October 30, 2017, extended on July 30, 2018, and expired on December 31, 2018. On October 26, 2018, the Company's Board of Directors approved an additional $300 million share repurchase authorization, which is not subject to an expiration date.

See Part III, Item 12. "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters" for information relating to CNX's equity compensation plans.

ITEM 6. Selected Financial Data

The following table presents our selected consolidated financial and operating data for, and as of the end of, each of the periods indicated. The selected consolidated financial data for, and as of the end of, each of the years ended December 31, 2018, 2017, 2016, 2015 and 2014 are derived from our audited Consolidated Financial Statements. Certain reclassifications of prior year data have been made to conform to the year ended December 31, 2018 presentation. The selected consolidated financial and operating data are not necessarily indicative of the results that may be expected for any future period. The selected consolidated financial and operating data should be read in conjunction with Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the financial statements and related notes included in this Annual Report.

(Dollars in thousands, except per share data)	**For the Years Ended December 31,**				
	2018	**2017**	**2016**	**2015**	**2014**
Revenue and Other Operating Income from Continuing Operations	$1,730,434	$1,455,131	$759,968	$1,198,737	$1,080,351
Income (Loss) from Continuing Operations	$883,111	$295,039	$(550,945)	$(650,198)	$(269,625)
Net Income (Loss) Attributable to CNX Resources Shareholders	$796,533	$380,747	$(848,102)	$(374,885)	$163,090
Earnings per share:					
Basic:					
Income (Loss) from Continuing Operations	$3.75	$1.29	$(2.40)	$(2.84)	$(1.17)
Income (Loss) from Discontinued Operations	—	0.37	(1.30)	1.20	1.88
Net Income (Loss)	$3.75	$1.66	$(3.70)	$(1.64)	$0.71
Diluted:					
Income (Loss) from Continuing Operations	$3.71	$1.28	$(2.40)	$(2.84)	$(1.17)
Income (Loss) from Discontinued Operations	—	0.37	(1.30)	1.20	1.87
Net Income (Loss)	$3.71	$1.65	$(3.70)	$(1.64)	$0.70
Assets from Continuing Operations	$8,592,170	$6,931,913	$6,682,770	$7,302,119	$7,968,069
Assets from Discontinued Operations	—	—	2,496,921	3,627,783	3,686,576
Total Assets	$8,592,170	$6,931,913	$9,179,691	$10,929,902	$11,654,645
Long-Term Debt from Continuing Operations (including current portion)	$2,398,501	$2,214,484	$2,456,354	$2,460,633	$3,129,433
Long-Term Debt from Discontinued Operations (including current portion)	—	—	317,715	294,222	120,128
Total Long-Term Debt (including current portion)	$2,398,501	$2,214,484	$2,774,069	$2,754,855	$3,249,561
Cash Dividends Declared Per Share of Common Stock	$—	$—	$0.010	$0.145	$0.250

See Item 1A, "Risk Factors" and Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" for a discussion of an adjustment to operating income for all periods and other matters that affect the comparability of the selected financial data as well as uncertainties that might affect the Company's future financial condition.

OTHER OPERATING DATA
(unaudited)

	Years Ended December 31,				
	2018	**2017**	**2016**	**2015**	**2014**
Gas:					
Net sales volumes produced (in Bcfe)	507.1	407.2	394.4	328.7	235.7

Average sales price ($ per Mcfe) (A)	$2.97	$2.66	$2.63	$2.81	$4.37
Average cost ($ per Mcfe)	$1.98	$2.23	$2.32	$2.62	$3.13
Proved reserves (in Bcfe) (B)	7,881	7,582	6,252	5,643	6,828

(A) Represents average net sales price including the effect of derivative transactions.
(B) Represents proved developed and undeveloped gas reserves at period end.

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

General

2018 Highlights

- Record total gas production of 507.1 Bcfe in 2018, 24.5% higher than 2017
  Included in CNX's 2018 production is approximately 27 Bcfe of production related to assets that were sold in 2018.
- Record Marcellus Shale production of 288.2 Bcfe in 2018, 20.4% higher than 2017.
- Increased proved reserves to 7.9 Tcfe, 4% higher than 2017.
  Increase even after a reduction of approximately 825 Bcfe of reserves related to assets that were sold in 2018.
- On January 3, 2018, the Company acquired the remaining 50% membership interest in CONE Gathering LLC (which has since been renamed CNX Gathering LLC), which holds the general partner interest and incentive distribution rights in CNXM, the entity that constructs and operates the gathering system for most of our Marcellus shale production.
- CNX sold substantially all of its shallow oil and gas assets and certain Coalbed Methane (CBM) assets in Pennsylvania and West Virginia during the second quarter of 2018.
- During the third quarter of 2018, CNX closed on the sale of substantially all of its Ohio Utica Joint Venture Assets in the wet gas Utica Shale areas of Belmont, Guernsey, Harrison, and Noble Counties, which included approximately 26,000 net undeveloped acres.
- Gas production costs continue to decline - for the year ended December 31, 2018, total gas production costs were $1.98 per Mcfe, which includes $0.90 per Mcfe of depreciation, depletion and amortization, a 11.2% decline from the prior year.
- Repurchased $384 million of common stock on the open market.
- Repurchased $411 million of 5.875% notes due in 2022.
- Called the remaining $500 million balance of 8% senior notes due April 2023.

2019 Outlook:

- Our 2019 annual gas production is expected to be at a minimum base of approximately 495-515 Bcfe.
- Our 2019 E&P capital investment is expected to be approximately $1,000-$1,080 million.

Results of Operations: ***Year Ended December 31, 2018 Compared with the Year Ended December 31, 2017***
Net Income Attributable to CNX Resources Shareholders
CNX reported net income attributable to CNX Resources shareholders of $797 million, or earnings per diluted share of $3.71, for the year ended December 31, 2018, compared to net income of $381 million, or earnings per diluted share of $1.65, for the year ended December 31, 2017.

	For the Years Ended December 31,		
(Dollars in thousands)	**2018**	**2017**	**Variance**
Income from Continuing Operations	$883,111	$295,039	$588,072
Income from Discontinued Operations, Net	—	85,708	(85,708)
Net Income	$883,111	$380,747	$502,364
Less: Net Income Attributable to Noncontrolling Interest	86,578	—	86,578
Net Income Attributable to CNX Resources Shareholders	$796,533	$380,747	$415,786

CNX consists of two principal business divisions: Exploration and Production (E&P) and Midstream.

The principal activity of the E&P Division is to produce pipeline quality natural gas for sale primarily to gas wholesalers. The E&P division's reportable segments are Marcellus Shale, Utica Shale, CBM, and Other Gas.

CNX's E&P Division had earnings from continuing operations before income tax of $245 million for the year ended December 31, 2018, compared to a loss from continuing operations before income tax of $63 million for the year ended December 31, 2017. Included in 2018 earnings was an unrealized gain on commodity derivative instruments of $40 million. Included in the 2017 loss was an unrealized gain on commodity derivative instruments of $248 million and $138 million of expense relating to the impairment in carrying value of Knox Energy LLC and Coalfield Pipeline Company (collectively, "Knox Energy"). See Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

CNX's Midstream Division's principal activity is the ownership, operation, development and acquisition of natural gas gathering and other midstream energy assets, through CNX Gathering and CNXM, which provide natural gas gathering services for the Company's produced gas, as well as for other independent third-parties in the Marcellus Shale and Utica Shale in Pennsylvania and West Virginia. Excluded from the Midstream Division are the gathering assets and operations of CNX that have not been contributed to CNX Gathering and CNXM.

CNX's Midstream Division, which is the result of CNX's acquisition of NBL Midstream, LLC's interest in CNX Gathering LLC (See Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information) on January 3, 2018 (the Midstream Acquisition), had earnings from continuing operations before income tax of $134 million for the period from January 3, 2018 through December 31, 2018. As a result of the Midstream Acquisition, CNX owns and controls 100% of CNX Gathering, making CNXM a single-sponsor master limited partnership. Prior to the acquisition, CNX accounted for its interests in CNX Gathering and CNXM as an equity-method investment and as such a period to period analysis is not meaningful. The resulting gain on remeasurement to fair value of the previously held equity interest in CNX Gathering and CNXM of $624 million has been included in Gain on Previously Held Equity Interest in the Consolidated Statements of Income and is part of CNX's unallocated expenses.

E&P Division Summary

Sales volumes, average sales price (including the effects of derivatives instruments), and average costs for the E&P Division were as follows:

	For the Years Ended December 31,			
	2018	2017	Variance	Percent Change
Sales Volume (Bcfe)	507.1	407.2	99.9	24.5 %
Average Sales Price (per Mcfe)	$2.97	$2.66	$0.31	11.7 %
Lease Operating Expense (per Mcfe)	0.19	0.22	(0.03)	(13.6)%
Production, Ad Valorem, and Other Fees (per Mcfe)	0.06	0.07	(0.01)	(14.3)%
Transportation, Gathering and Compression (per Mcfe)	0.84	0.94	(0.10)	(10.6)%
Depreciation, Depletion and Amortization (DD&A) (per Mcfe)	0.89	1.00	(0.11)	(11.0)%
Average Costs (per Mcfe)	$1.98	$2.23	$(0.25)	(11.2)%
Average Margin (per Mcfe)	$0.99	$0.43	$0.56	130.2 %

Natural gas, NGLs, and oil revenue was $1,578 million for the year ended December 31, 2018, compared to $1,125 million for the year ended December 31, 2017. The increase was primarily due to the 24.5% increase in total sales volumes and 11.7% increase in average sales price.

The 24.5% increase in total sales volumes was primarily due to additional natural gas wells that were turned-in-line in the latter half of the 2017 period as well as throughout the 2018 period. These wells were primarily Marcellus and Utica wells. The production for 2018 also includes approximately 27 Bcfe of production related to assets that were sold during the year. For additional information, see Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K and incorporated herein.

The increase in average sales price was primarily the result of a $0.38 per Mcf increase in general natural gas market prices in the Appalachian basin during the current period, partially offset by a $0.03 per Mcfe decrease in the uplift from NGLs and condensate sales volumes when excluding the impact of hedging and the $0.04 increase in the realized loss on commodity derivative instruments related to the Company's hedging program.

Changes in the average costs per Mcfe were primarily related to the following items:

- Lease operating expense decreased on a per unit basis due to the overall increase in sales volumes, primarily Utica, in the 2018. There were also significant decreases in routine well operating costs, repairs and maintenance expenses and employee costs, partially due to the sale of substantially all our shallow oil and gas properties in the first quarter. See Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information. In 2018, the company also deployed more in-house resources that maintained overall lease operating costs and increased operational efficiencies while significantly increasing production. The decreases were partially offset by increased water disposal costs, primarily in the first quarter of 2018, resulting from increased production volumes and gaps in the completions schedule for new wells.
- Transportation, gathering, and compression expense decreased on a per-unit basis primarily due to the 24.5% increase in sales volumes, and the shift towards dry Utica Shale production which has lower gathering costs and no processing costs. In the third quarter of 2018, CNX closed on the sale of substantially all of its Ohio Utica Joint Venture Assets in the wet gas Utica Shale areas (see Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for more information).
- Depreciation, depletion, and amortization decreased on a per-unit basis primarily due to a reduction in Marcellus Shale and Utica Shale rates as a result of an increase in the Company's associated reserves and an overall change in production mix.

The following table presents a breakout of net liquid and natural gas sales information to assist in the understanding of the Company's natural gas production and sales portfolio.

	For the Years Ended December 31,			
in thousands (unless noted)	**2018**	**2017**	**Variance**	**Percent Change**
LIQUIDS				
NGLs:				
Sales Volume (MMcfe)	36,489	38,736	(2,247)	(5.8)%
Sales Volume (Mbbls)	6,081	6,456	(375)	(5.8)%
Gross Price ($/Bbl)	$27.30	$24.18	$3.12	12.9 %
Gross Revenue	$165,883	$156,132	$9,751	6.2 %
Oil:				
Sales Volume (MMcfe)	307	421	(114)	(27.1)%
Sales Volume (Mbbls)	51	70	(19)	(27.1)%
Gross Price ($/Bbl)	$59.34	$45.36	$13.98	30.8 %
Gross Revenue	$3,036	$3,179	$(143)	(4.5)%
Condensate:				
Sales Volume (MMcfe)	2,082	3,116	(1,034)	(33.2)%
Sales Volume (Mbbls)	347	519	(172)	(33.1)%
Gross Price ($/Bbl)	$50.58	$39.54	$11.04	27.9 %
Gross Revenue	$17,559	$20,531	$(2,972)	(14.5)%
GAS				
Sales Volume (MMcf)	468,226	364,893	103,333	28.3 %
Sales Price ($/Mcf)	$2.97	$2.59	$0.38	14.7 %
Gross Revenue	$1,391,459	$945,382	$446,077	47.2 %
Hedging Impact ($/Mcf)	$(0.15)	$(0.11)	$(0.04)	(36.4)%
Loss on Commodity Derivative Instruments - Cash Settlement	$(69,720)	$(41,174)	$(28,546)	(69.3)%

Selling, General and Administrative (SG&A) - Total Company

SG&A costs include costs such as overhead, including employee wages and benefit costs, short-term incentive compensation, costs of maintaining our headquarters, audit and other professional fees, and legal compliance expenses. SG&A costs also include noncash equity-based compensation expense.

SG&A costs were $135 million for the year ended December 31, 2018, compared to $93 million for the year ended December 31, 2017. SG&A costs increased primarily due to the Midstream Acquisition in January 2018, which now requires us to consolidate CNX Gathering and CNXM expenses as well as an increase in short-term incentive compensation expense. See Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 1 of this Form 10-K for additional information on the Midstream Acquisition. Prior to the Midstream Acquisition, CNX accounted for its interests in CNX Gathering and CNXM as an equity-method investment.

Unallocated Expense

Certain costs and expenses, such as other (income) expense, gain on sale of assets related to non-core assets, gain on previously held equity interest, loss on debt extinguishment, impairment of other intangible assets and income taxes are unallocated expenses and therefore are excluded from the per unit costs above as well as segment reporting. Below is a summary of these costs and expenses:

Other (Income) Expense

(in millions)	For the Years Ended December 31, 2018	2017	Variance	Percent Change
Other Income				
Right of Way Sales	$14	$2	$ 12	600.0 %
Royalty Income	15	10	5	50.0 %
Interest Income	—	9	(9)	(100.0)%
Other	8	6	2	33.3 %
Total Other Income	$37	$27	$ 10	37.0 %
Other Expense				
Bank Fees	$11	$13	$ (2)	(15.4)%
Professional Services	7	6	1	16.7 %
Other Land Rental Expense	4	6	(2)	(33.3)%
Other Corporate Expense	—	6	(6)	(100.0)%
Total Other Expense	$22	$31	$ (9)	(29.0)%
Total Other (Income) Expense	$(15)	$4	$ (19)	(475.0)%

Gain on Sale of Assets

CNX recognized a gain on sale of assets of $157 million in the year ended December 31, 2018 compared to a gain of $188 million in the year ended December 31, 2017. During the year ended December 31, 2018, CNX closed on the sale of substantially all of its Ohio Utica Joint Venture Assets in the wet gas Utica Shale areas of Ohio and substantially all of its shallow oil and gas assets and certain CBM assets in Pennsylvania and West Virginia. The net gain on the sale of these assets was $136 million and is included in the Gain on Sale of Assets line on the Consolidated Statements of Income. During the year ended December 31, 2017, CNX closed on the sale of approximately 22,000 acres of surface land in Colorado, the sale of approximately 7,500 net undeveloped acres of the Marcellus Shale in Pennsylvania, the sale of approximately 11,100 net undeveloped acres of the Marcellus and Utica Shale in Pennsylvania, and the sale of approximately 6,300 net undeveloped acres of the Utica-Point Pleasant Shale in Ohio. The net gain on the sale of these assets was $165 million and is included in Gain on Sale of Assets in the Consolidated Statements of Income. The remaining decrease in the period-to-period comparison is due to various items that occurred throughout both periods, none of which were individually material. See Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Gain on Previously Held Equity Interest

CNX recognized a gain on previously held equity interest of $624 million in the year ended December 31, 2018 due to the Midstream Acquisition in January 2018. No such transactions occurred in the year ended December 31, 2017. See Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Loss on Debt Extinguishment

A loss on debt extinguishment of $54 million was recognized in the year ended December 31, 2018 compared to a loss on debt extinguishment of $2 million in the year ended December 31, 2017. During the year ended December 31, 2018, CNX purchased a portion of its 5.875% senior notes due in April 2022 at an average price equal to103.5% of the principal amount and redeemed the 8.00% senior notes due in April 2023 at a call price equal to 106.0% of the principal amount. In the year ended December 31, 2017, CNX purchased a portion of its 5.875% senior notes due in April 2022 at an average price equal to 99.5% of the principal amount, redeemed the 8.25% senior notes due in April 2020 at a call price equal to 101.375% of the principal amount, and redeemed the 6.375% senior notes due in March 2021 at a call price equal to 102.125% of the principal amount. See Note 14 - Long Term Debt in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Impairment of Other Intangible Assets

Intangible assets are tested for impairment whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. An impairment loss would be recognized when the carrying amount of the asset exceeds the estimated undiscounted future cash flows expected to result from the use of the asset and its eventual disposition. The impairment loss to be recorded would be the excess of the asset's carrying value over its fair value.

In connection with the Asset Exchange Agreement (AEA) with HG Energy transactions (See Note 6 - Acquisition and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information) that occurred during the year ended December 31, 2018, CNX determined that the carrying value of the other intangible asset - customer relationship exceeded its fair value, and an impairment of $19 million was included in Impairment of Other Intangible Assets in the Consolidated Statement of Income. No such transactions occurred in the prior period.

Income Taxes

The effective income tax rate for continuing operations was 19.6% for the year ended December 31, 2018, compared to (148.9)% for the year ended December 31, 2017. During the year ended December 31, 2018, CNX obtained a controlling interest in CNX Gathering LLC and, through CNX Gathering's ownership of the general partner, control over the CNXM. All of CNXM’s income is included in the Company's pre-tax income. However, the Company is not required to record income tax expense with respect to the portions of CNXM’s income allocated to the noncontrolling public limited partners of CNXM, which reduces the Company's effective tax rate in periods when the Company has consolidated pre-tax income and increases the Company's effective tax rate in periods when the Company has consolidated pre-tax loss. The effective tax rate for the year ended December 31, 2018 was lower than the U.S. federal statutory rate primarily due to the non-controlling interest in CNXM, the effect of the filing of a Federal net operating loss ("NOL") carryback for 2017 and 2016 resulting in a financial statement benefit of $23 million through the realization of the Federal NOLs at a 35% tax rate as a carryback versus the current 21% tax rate as a carryforward generating cash tax refunds to be received in 2019, the reversal of the alternative minimum tax ("AMT") credit sequestration valuation allowance, and the release of certain state valuation allowances as a result of a corporate reorganization during the year.

On December 22, 2017, the United States enacted the Tax Cuts and Jobs Act (the "Act") which, among other things, lowered the U.S. Federal income tax rate from 35% to 21%, repealed the corporate AMT, and provided for a refund of previously accrued AMT credits. The Company reclassified $102 million from Deferred Income Taxes to Recoverable Income Taxes on the Consolidated Balance Sheets in anticipation of a refund of 50% of the AMT credits expected to be received in 2019. The valuation allowance associated with the AMT credits of $12 million was released as the Internal Revenue Service ("IRS") announced that the AMT credits are no longer subject to government sequestration.

The Company recorded a net tax benefit to reflect the impact of the Act as of December 31, 2017, as it is required to reflect the change in the period in which the law is enacted. Largely, the benefits recorded in the prior period related to tax reform are in recognition of the revaluation of deferred tax assets and liabilities, a benefit of $115 million, and the benefit for reversal of valuation allowance previously recorded against AMT credits which are now refundable, a benefit of $154 million.

See Note 8 - Income Taxes in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

	For the Years Ended December 31,			
	2018	**2017**	**Variance**	**Percent Change**
Total Company Earnings Before Income Tax	$1,099	$119	$980	823.5 %
Income Tax Expense (Benefit)	$216	$(176)	$392	(222.7)%

Effective Income Tax Rate	19.6 %	(148.9)%	168.5%

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TOTAL E&P DIVISION ANALYSIS for the year ended December 31, 2018 compared to the year ended December 31, 2017:

The E&P division had earnings from continuing operations before income tax of $245 million for the year ended December 31, 2018 compared to a loss from continuing operations before income tax of $63 million for the year ended December 31, 2017. Variances by individual operating segment are discussed below.

	For the Year Ended December 31, 2018					Difference to Year Ended December 31, 2017				
(in millions)	Marcellus	Utica	CBM	Other Gas	Total	Marcellus	Utica	CBM	Other Gas	Total
Natural Gas, NGLs and Oil Revenue	$903	$446	$213	$16	$1,578	$257	$229	$4	$(37)	$453
(Loss) Gain on Commodity Derivative Instruments	(40)	(20)	(9)	39	(30)	(10)	(21)	1	(207)	(237)
Purchased Gas Revenue	—	—	—	66	66	—	—	—	12	12
Other Operating Income	—	—	—	27	27	—	—	—	(42)	(42)
Total Revenue and Other Operating Income	863	426	204	148	1,641	247	208	5	(274)	186
Lease Operating Expense	41	30	22	2	95	9	11	(3)	(11)	6
Production, Ad Valorem, and Other Fees	18	7	7	1	33	3	2	—	(1)	4
Transportation, Gathering and Compression	320	52	48	4	424	64	7	(16)	(14)	41
Depreciation, Depletion and Amortization	230	143	77	11	461	8	59	(6)	(12)	49
Impairment of Exploration and Production Properties	—	—	—	—	—	—	—	—	(138)	(138)
Exploration and Production Related Other Costs	—	—	—	12	12	—	—	—	(36)	(36)
Purchased Gas Costs	—	—	—	65	65	—	—	—	12	12
Other Operating Expense	—	—	—	72	72	—	—	—	(40)	(40)
Selling, General, and Administrative Costs	—	—	—	112	112	—	—	—	19	19
Total Operating Costs and Expenses	609	232	154	279	1,274	84	79	(25)	(221)	(83)
Interest Expense	—	—	—	122	122	—	—	—	(39)	(39)
Total E&P Division Costs	609	232	154	401	1,396	84	79	(25)	(260)	(122)
Earnings (Loss) from Continuing Operations Before Income Tax	$254	$194	$50	$(253)	$245	$163	$129	$30	$(14)	$308

MARCELLUS SEGMENT

The Marcellus segment had earnings from continuing operations before income tax of $254 million for the year ended December 31, 2018 compared to earnings from continuing operations before income tax of $91 million for the year ended December 31, 2017.

	For the Years Ended December 31,			
	2018	2017	Variance	Percent Change
Marcellus Gas Sales Volumes (Bcf)	255.1	209.7	45.4	21.6 %
NGLs Sales Volumes (Bcfe)*	31.4	27.6	3.8	13.8 %
Condensate Sales Volumes (Bcfe)*	1.7	2.1	(0.4)	(19.0)%
Total Marcellus Sales Volumes (Bcfe)*	288.2	239.4	48.8	20.4 %
Average Sales Price - Gas (per Mcf)	$2.93	$2.50	$0.43	17.2 %
Loss on Commodity Derivative Instruments - Cash Settlement- Gas (per Mcf)	$(0.16)	$(0.14)	$(0.02)	(14.3)%
Average Sales Price - NGLs (per Mcfe)*	$4.55	$3.96	$0.59	14.9 %
Average Sales Price - Condensate (per Mcfe)*	$8.32	$6.44	$1.88	29.2 %
Total Average Marcellus Sales Price (per Mcfe)	$2.99	$2.57	$0.42	16.3 %
Average Marcellus Lease Operating Expenses (per Mcfe)	0.14	0.13	0.01	7.7 %
Average Marcellus Production, Ad Valorem, and Other Fees (per Mcfe)	0.07	0.07	—	— %
Average Marcellus Transportation, Gathering and Compression Costs (per Mcfe)	1.11	1.07	0.04	3.7 %
Average Marcellus Depreciation, Depletion and Amortization Costs (per Mcfe)	0.79	0.92	(0.13)	(14.1)%
Total Average Marcellus Costs (per Mcfe)	$2.11	$2.19	$(0.08)	(3.7)%
Average Margin for Marcellus (per Mcfe)	$0.88	$0.38	$0.50	131.6 %

*** NGLs and Condensate are converted to Mcfe at the rate of one barrel equals six Mcf based upon the approximate relative energy content of oil and natural gas, which is not indicative of the relationship of oil, NGLs, condensate, and natural gas prices.**

The Marcellus segment had natural gas, NGLs and oil revenue of $903 million for the year ended December 31, 2018 compared to $646 million for the year ended December 31, 2017. The $257 million increase was primarily due to the 20.4% increase in total Marcellus sales volumes, including liquids, as well as the 16.3% increase in the total average Marcellus sales price in the period-to-period comparison. The increase in sales volumes was primarily due to additional wells being turned-in-line in the latter half of 2017 and throughout 2018.

The increase in the total average Marcellus sales price was primarily the result of the $0.43 per Mcf increase in average gas sales price and a $0.01 per Mcfe increase in the uplift from NGLs and condensate sales volume when excluding the impact of hedging, partially offset by the $0.02 per Mcfe increase in the loss on commodity derivative instruments resulting from the Company's hedging program. The notional amounts associated with these financial hedges represented approximately 206.7 Bcf of the Company's produced Marcellus gas sales volumes for the year ended December 31, 2018 at an average loss of $0.20 per Mcf. For the year ended December 31, 2017, these financial hedges represented approximately 177.6 Bcf at an average loss of $0.17 per Mcf.

Total operating costs and expenses for the Marcellus segment were $609 million for the year ended December 31, 2018 compared to $525 million for the year ended December 31, 2017. The increase in total dollars and decrease in unit costs for the Marcellus segment were due primarily to the following items:

•Marcellus lease operating expense was $41 million for the year ended December 31, 2018 compared to $32 million for the year ended December 31, 2017. The increase in total dollars was primarily due to an increase in water disposal costs in the current period due to increased production volumes along with proportionally more water being sent to disposal in the first quarter of 2018 instead of being reused in completions. The increase in unit costs was driven by the increase in total dollars, partially offset by the 20.4% increase in total Marcellus sales volumes.

•Marcellus production, ad valorem, and other fees were $18 million for the year ended December 31, 2018 compared to $15 million for the year ended December 31, 2017. The increase in total dollars was primarily due to the increase in overall Marcellus production as well as a change in production mix by state as new wells are turned in line.

•Marcellus transportation, gathering and compression costs were $320 million for the year ended December 31, 2018 compared to $256 million for the year ended December 31, 2017. The $64 million increase in total dollars was primarily related to an increase in gathering, processing and utilized firm transportation costs due to increased volumes and increased processing costs due to a change in production mix which includes a greater proportion of higher cost wet gas. The increase in unit costs was due to the increased total dollars described above, partially offset by the 20.4% increase in Marcellus sales volumes.

•Depreciation, depletion and amortization costs attributable to the Marcellus segment were $230 million for the year ended December 31, 2018 compared to $222 million for the year ended December 31, 2017. These amounts included depletion on a unit of production basis of $0.79 per Mcf and $0.91 per Mcf, respectively. The remaining depreciation, depletion and amortization costs were either recorded on a straight-line basis or related to gas well closing.

UTICA SEGMENT

The Utica segment had earnings from continuing operations before income tax of $194 million for the year ended December 31, 2018 compared to earnings from continuing operations before income tax of $65 million for the year ended December 31, 2017.

	For the Years Ended December 31,			
	2018	2017	Variance	Percent Change
Utica Gas Sales Volumes (Bcf)	148.1	70.7	77.4	109.5 %
NGLs Sales Volumes (Bcfe)*	5.1	11.1	(6.0)	(54.1)%
Oil Sales Volumes (Bcfe)*	0.1	0.2	(0.1)	(50.0)%
Condensate Sales Volumes (Bcfe)*	0.4	1.0	(0.6)	(60.0)%
Total Utica Sales Volumes (Bcfe)*	153.7	83.0	70.7	85.2 %
Average Sales Price - Gas (per Mcf)	$2.82	$2.29	$0.53	23.1 %
(Loss) Gain on Commodity Derivative Instruments - Cash Settlement- Gas (per Mcf)	$(0.13)	$0.02	$(0.15)	(750.0)%
Average Sales Price - NGLs (per Mcfe)*	$4.54	$4.20	$0.34	8.1 %
Average Sales Price - Oil (per Mcfe)*	$9.46	$7.31	$2.15	29.4 %
Average Sales Price - Condensate (per Mcfe)*	$8.96	$6.88	$2.08	30.2 %
Total Average Utica Sales Price (per Mcfe)	$2.77	$2.63	$0.14	5.3 %
Average Utica Lease Operating Expenses (per Mcfe)	0.19	0.23	(0.04)	(17.4)%
Average Utica Production, Ad Valorem, and Other Fees (per Mcfe)	0.05	0.06	(0.01)	(16.7)%
Average Utica Transportation, Gathering and Compression Costs (per Mcfe)	0.34	0.54	(0.20)	(37.0)%
Average Utica Depreciation, Depletion and Amortization Costs (per Mcfe)	0.93	1.02	(0.09)	(8.8)%
Total Average Utica Costs (per Mcfe)	$1.51	$1.85	$(0.34)	(18.4)%
Average Margin for Utica (per Mcfe)	$1.26	$0.78	$0.48	61.5 %

***NGLs and Condensate are converted to Mcfe at the rate of one barrel equals six mcf based upon the approximate relative energy content of oil and natural gas, which is not indicative of the relationship of oil, NGLs, condensate, and natural gas prices.**

The Utica segment had natural gas, NGLs and oil revenue of $446 million for the year ended December 31, 2018 compared to $217 million for the year ended December 31, 2017. The $229 million increase was due to the 85.2% increase in total Utica sales volumes as well as the 5.3% increase in total average Utica sales price. The 70.7 Bcfe increase in total Utica sales volumes was primarily due to additional wells turned-in-line beginning in the third quarter of 2017 and throughout the 2018 period, primarily in Monroe County, Ohio. The increase was partially offset by the sale of substantially all of CNX's Ohio Utica Joint Venture Assets, during the third quarter of 2018, in the wet gas Utica Shale areas (See Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for more information).

The increase in the total average Utica sales price was primarily due to the $0.53 increase in average gas sales price, offset, in part, by a $0.24 decrease in the uplift from NGLs and condensate sales volumes when excluding the impact of hedging. Part of the decrease in the uplift from NGLs and condensate sales volumes was due to the sale of the CNX's Ohio Utica Joint Venture Assets in the wet gas Utica Shale areas, as discussed above. There was also a $0.15 per Mcf decrease in the (loss) gain on commodity derivative instruments in the current period. The notional amounts associated with these financial hedges represented approximately 101.6 Bcf of the Company's produced Utica gas sales volumes for the year ended December 31, 2018 at an average loss of $0.20 per Mcf. For the year ended December 31, 2017, these financial hedges represented approximately 39.8 Bcf at an average gain of $0.04 per Mcf.

Total operating costs and expenses for the Utica segment were $232 million for the year ended December 31, 2018 compared to $153 million for the year ended December 31, 2017. The increase in total dollars and decrease in unit costs for the Utica segment are due to the following items:

•Utica lease operating expense increased to $30 million for the year ended December 31, 2018, compared to $19 million for the year ended December 31, 2017. The increase in total dollars was primarily due to higher well tending and water disposal costs in the current period associated with the additional sales volumes. The decrease in unit costs was due to the 85.2% increase in total Utica sales volumes.

•Utica production, ad valorem, and other fees were $7 million for the year ended December 31, 2018 compared to $5 million for the year ended December 31, 2017. The increase in total dollars was primarily due to the overall increase in Utica production as well as a change in production mix by state as new wells are turned-in-line. The decrease in unit costs was due to the increase in production volumes.

•Utica transportation, gathering and compression costs were $52 million for the year ended December 31, 2018 compared to $45 million for the year ended December 31, 2017. The $7 million increase in total dollars was primarily related to the increased production in the current period. The decrease in unit costs was due to the increase in total Utica sales volumes, predominantly dry Utica which does not require processing. In the third quarter of 2018, CNX closed on the sale of substantially all of its Ohio Utica Joint Venture Assets in the wet gas Utica Shale areas (see Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for more information).

•Depreciation, depletion and amortization costs attributable to the Utica segment were $143 million for the year ended December 31, 2018 compared to $84 million for the year ended December 31, 2017. These amounts included depletion on a unit of production basis of $0.93 per Mcf and $1.01 per Mcf, respectively. The remaining depreciation, depletion and amortization costs were either recorded on a straight-line basis or related to gas well closing.

COALBED METHANE (CBM) SEGMENT

The CBM segment had earnings from continuing operations before income tax of $50 million for the year ended December 31, 2018 compared to earnings from continuing operations before income tax of $20 million for the year ended December 31, 2017.

	For the Years Ended December 31,										
	2018			2017			Variance			Percent Change	
CBM Gas Sales Volumes (Bcf)	60.3			65.4			(5.1		)	(7.8	)%
Average Sales Price - Gas (per Mcf)	$	3.53		$	3.19		$	0.34		10.7	%
Loss on Commodity Derivative Instruments - Cash Settlement- Gas (per Mcf)	$	(0.15	)	$	(0.15	)	$	—		—	%
Total Average CBM Sales Price (per Mcf)	$	3.39		$	3.05		$	0.34		11.1	%
Average CBM Lease Operating Expenses (per Mcf)	0.37			0.39			(0.02		)	(5.1	)%
Average CBM Production, Ad Valorem, and Other Fees (per Mcf)	0.12			0.11			0.01			9.1	%
Average CBM Transportation, Gathering and Compression Costs (per Mcf)	0.80			0.98			(0.18		)	(18.4	)%
Average CBM Depreciation, Depletion and Amortization Costs (per Mcf)	1.28			1.26			0.02			1.6	%
Total Average CBM Costs (per Mcf)	$	2.57		$	2.74		$	(0.17	)	(6.2	)%
Average Margin for CBM (per Mcf)	$	0.82		$	0.31		$	0.51		164.5	%

The CBM segment had natural gas sales of $213 million for the year ended December 31, 2018 compared to $209 million for the year ended December 31, 2017. The $4 million increase was due to a 11.1% increase in the total average CBM sales price, offset, in part, by the 7.8% decrease in CBM gas sales volumes. The decrease in CBM sales volumes was primarily due to normal well declines, less drilling activity and the sale of certain CBM assets that were sold along with the majority of CNX's shallow oil and gas assets (See Note 6 - Acquisitions and Dispositions of the

Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information).

The total average CBM sales price increased due to the $0.34 per Mcf increase in the average gas sales price. The loss on commodity derivative instruments remained consistent year over year. The notional amounts associated with these financial hedges represented approximately 44.8 Bcf of the Company's produced CBM sales volumes for the year ended December 31, 2018 at an average loss of $0.20 per Mcf. For the year ended December 31, 2017, these financial hedges represented approximately 56.3 Bcf at an average loss of $0.17 per Mcf.

Total operating costs and expenses for the CBM segment were $154 million for the year ended December 31, 2018 compared to $179 million for the year ended December 31, 2017. The decrease in total dollars and decrease in unit costs were due to the following items:

•CBM lease operating expense was $22 million for the year ended December 31, 2018 compared to $25 million for the year ended December 31, 2017. The decrease in total dollars was primarily due to reductions in contract services. The decrease in unit costs was due to the decrease in total dollars as well as the decrease in CBM gas sales volumes.

•CBM production, ad valorem, and other fees remained consistent at $7 million for each of the years ended December 31, 2018 and December 31, 2017. Unit costs were negatively impacted by the decrease in CBM gas sales volumes.

•CBM transportation, gathering and compression costs were $48 million for the year ended December 31, 2018 compared to $64 million for the year ended December 31, 2017. The $16 million decrease was primarily related to a decrease in contractor services. The decrease was also due to a decrease in utilized firm transportation expense due to a new compressor station that began operating in the third quarter of 2017. This station allows CNX to flow more production through the Jewel Ridge Pipeline, which is treated as a capital lease. Unit costs were also positively impacted by the decrease in total dollars which was offset, in part, by the decrease in CBM gas sales volumes.

•Depreciation, depletion and amortization costs attributable to the CBM segment were $77 million for the year ended December 31, 2018 compared to $83 million for the year ended December 31, 2017. These amounts included depletion on a unit of production basis of $0.70 per Mcf and $0.78 per Mcf, respectively. The remaining depreciation, depletion and amortization costs were either recorded on a straight-line basis or related to gas well closing.

OTHER GAS SEGMENT

The Other Gas segment had a loss from continuing operations before income tax of $253 million for the year ended December 31, 2018 compared to a loss from continuing operations before income tax of $239 million for the year ended December 31, 2017.

	For the Years Ended December 31,			
	2018	**2017**	**Variance**	**Percent Change**
Other Gas Sales Volumes (Bcf)	4.7	19.2	(14.5)	(75.5)%
Oil Sales Volumes (Bcfe)*	0.2	0.2	—	— %
Total Other Sales Volumes (Bcfe)*	4.9	19.4	(14.5)	(74.7)%
Average Sales Price - Gas (per Mcf)	$2.91	$2.69	$0.22	8.2 %
(Loss) Gain on Commodity Derivative Instruments - Cash Settlement- Gas (per Mcf)	$(0.13)	$(0.14)	$0.01	7.1 %
Average Sales Price - Oil (per Mcfe)*	$10.09	$7.75	$2.34	30.2 %
Total Average Other Sales Price (per Mcfe)	$3.09	$2.62	$0.47	17.9 %
Average Other Lease Operating Expenses (per Mcfe)	0.42	0.63	(0.21)	(33.3)%
Average Other Production, Ad Valorem, and Other Fees (per Mcfe)	0.04	0.12	(0.08)	(66.7)%
Average Other Transportation, Gathering and Compression Costs (per Mcfe)	0.87	0.90	(0.03)	(3.3)%
Average Other Depreciation, Depletion and Amortization Costs (per Mcfe)	1.49	1.05	0.44	41.9 %
Total Average Other Costs (per Mcfe)	$2.82	$2.70	$0.12	4.4 %
Average Margin for Other (per Mcfe)	$0.27	$(0.08)	$0.35	437.5 %

***Oil is converted to Mcfe at the rate of one barrel equals six mcf based upon the approximate relative energy content of oil and natural gas, which is not indicative of the relationship of oil and natural gas prices.**

The Other Gas segment includes activity not assigned to the Marcellus, Utica, or CBM segments. This segment also includes purchased gas activity, unrealized gain or loss on commodity derivative instruments, exploration and production related other costs, impairment of exploration and production properties and other operational activity not assigned to a specific segment.

Other Gas sales volumes are primarily related to CNX's remaining shallow oil and gas production. CNX sold substantially all of these assets on March 30, 2018 (See Note 6 - Acquisitions and Dispositions of the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information). Natural gas, NGLs and oil revenue related to the Other Gas segment were $16 million for the year ended December 31, 2018 compared to $53 million for the year ended December 31, 2017. The decrease in natural gas and oil revenue resulted from the 74.7% decrease in total Other Gas sales volumes relating to the asset sale. Total exploration and production costs related to these other sales were $18 million for the year ended December 31, 2018 compared to $56 million for the year ended December 31, 2017.

The Other Gas segment recognized an unrealized gain on commodity derivative instruments of $40 million as well as cash settlements paid of $1 million for the year ended December 31, 2018. For the year ended December 31, 2017, the Company recognized an unrealized gain on commodity derivative instruments of $248 million as well as cash settlements paid of $2 million. The unrealized gain on commodity derivative instruments represents changes in the fair value of all the Company's existing commodity derivative hedges on a mark-to-market basis.

Purchased Gas

Purchased gas volumes represent volumes of gas purchased at market prices from third-parties and then resold in order to fulfill contracts with certain customers. Purchased gas revenue was $66 million for the year ended

December 31, 2018 compared to $54 million for the year ended December 31, 2017. Purchased gas costs were $65 million for the year ended December 31, 2018 compared to $53 million for the year ended December 31, 2017. The period-to-period increase in purchased gas revenue was primarily due to the increase in market prices, partially offset by the decrease in purchased gas sales volumes.

	For the Years Ended December 31,			
	2018	2017	Variance	Percent Change
Purchased Gas Sales Volumes (in billion cubic feet)	20.5	22.0	(1.5)	(6.8)%
Average Sales Price (per Mcf)	$3.23	$2.44	$0.79	32.4 %
Average Cost (per Mcf)	$3.17	$2.39	$0.78	32.6 %

Other Operating Income

Other operating income was $27 million for the year ended December 31, 2018 compared to $69 million for the year ended December 31, 2017. The $42 million decrease was primarily due to the following items:

	For the Years Ended December 31,			
(in millions)	2018	2017	Variance	Percent Change
Equity in Earnings of Affiliates	$5	$50	$ (45)	(90.0)%
Gathering Income	10	11	(1)	(9.1)%
Water Income	11	5	6	120.0 %
Other	1	3	(2)	(66.7)%
Total Other Operating Income	$27	$69	$ (42)	(60.9)%

- Equity in Earnings of Affiliates decreased $45 million primarily due to the consolidation of CNX Gathering and CNXM in the current year. See Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.
- Water Income increased $6 million due to increased sales of freshwater to third-parties for hydraulic fracturing.

Impairment of Exploration and Production Related Properties

Impairment of Exploration and Production Properties of $138 million for the year ended December 31, 2017 related to an impairment in the carrying value of Knox Energy in the first quarter of 2017. See Note 1 - Significant Accounting Policies and Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information. No such impairments occurred in the year ended December 31, 2018.

Exploration and Production Related Other Costs

Exploration and production related other costs were $12 million for the year ended December 31, 2018 compared to $48 million for the year ended December 31, 2017. The $36 million decrease in costs was primarily related to the following items:

	For the Years Ended December 31,			
(in millions)	2018	2017	Variance	Percent Change
Lease Expiration Costs	$5	$40	$ (35)	(87.5)%
Land Rentals	4	4	—	— %
Other	3	4	(1)	(25.0)%
Total Exploration and Production Related Other Costs	$12	$48	$ (36)	(75.0)%

- Lease Expiration Costs relate to leases where the primary term expired or will expire within the next 12 months. The $35 million decrease in the year ended December 31, 2018, was primarily due to leases in both Monroe and Noble County, Ohio that were no longer in the Company's future drilling plans, so they were not renewed in the 2017 period.

Other Operating Expenses

Other operating expense was $72 million for the year ended December 31, 2018 compared to $112 million for the year ended December 31, 2017. The $40 million decrease in the period-to-period comparison was made up of the following items:

	For the Years Ended December 31,			
	2018	**2017**	**Variance**	**Percent Change**
Idle Rig Expense	$5	$41	$ (36)	(87.8)%
Unutilized Firm Transportation and Processing Fees	42	50	(8)	(16.0)%
Severance Expense	1	1	—	— %
Insurance Expense	3	3	—	— %
Litigation Settlements	4	3	1	33.3 %
Other	17	14	3	21.4 %
Total Other Operating Expense	$72	$112	$ (40)	(35.7)%

- Idle Rig Expense relates to the temporary idling of some of the Company's natural gas rigs. The total idle rig expense incurred by the Company decreased $36 million in the period-to-period comparison due to contracts that expired in the current period. Additionally, the total idle rig expense decreased in the period-to-period comparison due to a settlement that was reached with a former joint-venture partner that resulted in CNX recording additional expense in the year ended December 31, 2017.
- Unutilized Firm Transportation and Processing Fees represent pipeline transportation capacity obtained to enable gas production to flow uninterrupted as sales volumes increase, as well as additional processing capacity for NGLs. The decrease in the period-to-period comparison was primarily due to the increase in the utilization of capacity. The Company attempts to minimize this expense by releasing (selling) unutilized firm transportation capacity to other parties when possible and when beneficial. The revenue received when this capacity is released (sold) is included in Gathering Income in other operating income above.

Selling, General and Administrative

SG&A costs represent direct charges for the management and operation of CNX's E&P division. SG&A costs were $112 million for the year ended December 31, 2018 compared to $93 million for the year ended December 31, 2017. Refer to the discussion of total company SG&A costs contained in the section "Net Income Attributable to CNX Resources Shareholders" of this Form 10-K for a detailed cost explanation.

Interest Expense

Interest expense of $122 million was recognized in the year ended December 31, 2018 compared to $161 million in the year ended December 31, 2017. The $39 million decrease was primarily due to a reduction in higher cost long-term debt, resulting from the $411 million purchase of the outstanding 5.875% senior notes due in April 2022 and the $500 million purchase of the outstanding 8% senior notes due in April 2023 in the year ended December 31, 2018, offset, in part, by additional borrowings on the CNX credit facility. In the year ended December 31, 2017, CNX purchased $144 million of its outstanding 5.875% senior notes due in April 2022. See Note 14 - Long-Term Debt in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

TOTAL MIDSTREAM DIVISION ANALYSIS for the period January 3, 2018 through December 31, 2018:

CNX's Midstream Division's principal activity is the ownership, operation, development and acquisition of natural gas gathering and other midstream energy assets of CNX Gathering and CNXM, which provide natural gas gathering services for the Company's produced gas, as well as for other independent third-parties in the Marcellus Shale and Utica Shale in Pennsylvania and West Virginia. Excluded from the Midstream Division are the gathering assets and operations of CNX that have not been contributed to CNX Gathering and CNXM.

On January 3, 2018, CNX completed the Midstream Acquisition (See Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information). CNX Gathering holds all of the interests in CNX Midstream GP, LLC, which holds the general partner interest and incentive distribution rights in CNXM. As a result of this transaction, CNX owns and controls 100% of CNX Gathering, making CNXM a single-sponsor master limited partnership and thus the Company consolidates both CNX Gathering and CNXM commencing on January 3, 2018. Prior to the acquisition, CNX accounted for its interests in CNX Gathering and CNXM as an equity-method investment and as such a period-to-period analysis is not meaningful.

(in millions)	**For the period January 3, 2018 through December 31, 2018**
Midstream Revenue - Related Party	$ 168
Midstream Revenue - Third Party	90
Total Revenue	$ 258
Transportation, Gathering and Compression	$ 47
Depreciation, Depletion and Amortization	32
Selling, General, and Administrative Costs	23
Total Operating Costs and Expenses	102
Gain on Asset Sales	(2)
Interest Expense	24
Total Midstream Division Costs	124
Earnings from Continuing Operations Before Income Tax	$ 134

Midstream Revenue

Midstream revenue consists of revenue related to volumes gathered on behalf of CNX and other third-party natural gas producers. CNXM charges a higher fee for natural gas that is shipped on its wet system compared to gas shipped through its dry system. CNXM revenue can also be impacted by the relative mix of gathered volumes by area, which may vary dependent upon delivery point and may change dynamically depending on commodity prices at time of shipment.

The table below summaries volumes gathered by gas type for the period January 3, 2018 through December 31, 2018.

	TOTAL
Dry Gas (BBtu/d) (*)	740
Wet Gas (BBtu/d) (*)	661
Other (BBtu/d) (*)(**)	73
Total Gathered Volumes	1,474

(*) Classification as dry or wet is based upon the shipping destination of the related volumes. Because CNXM's customers have the option to ship a portion of their natural gas to destinations associated with either our wet system or our dry system, due to any number of factors, volumes may be classified as “wet” in one period and as “dry” in the comparative period.
(**) Includes condensate handling and third-party volumes under high-pressure short-haul agreements.

Transportation, Gathering and Compression

Transportation, Gathering and Compression costs were $47 million for the period January 3, 2018 through December 31, 2018 and are comprised of items directly related to the cost of gathering natural gas at the wellhead and transporting it to interstate pipelines or other local sales points. These costs include items such as electrical compression, repairs and maintenance, supplies, treating and contract services.

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SG&A Expense

SG&A expense is comprised of direct charges for the management and operation of CNXM assets. Refer to the discussion of total Company SG&A costs contained in the section "Net Income Attributable to CNX Resources Shareholders" of this Form 10-K for a detailed cost explanation.

Depreciation, Depletion and Amortization

Depreciation expense is recognized on gathering and other equipment on a straight-line basis, with useful lives ranging from 25 years to 40 years.

Gain on Asset Sales

During the period January 3, 2018 through December 31, 2018, CNXM sold property and equipment to an unrelated third- party for $6 million in cash proceeds, resulting in a gain of $2 million.

Interest Expense

Interest expense is comprised of interest on the outstanding balance under CNXM's senior notes due 2026 and its revolving credit facility. Interest expense was $24 million for the period January 3, 2018 through December 31, 2018.

Results of Operations: ***Year Ended December 31, 2017 Compared with the Year Ended December 31, 2016***
Net Income (Loss)
CNX reported net income of $381 million, or earnings per diluted share of $1.65, for the year ended December 31, 2017, compared to a net loss of $848 million, or a loss per diluted share of $3.70, for the year ended December 31, 2016.

	For the Years Ended December 31,		
(Dollars in thousands)	**2017**	**2016**	**Variance**
Income (Loss) from Continuing Operations	$295,039	$(550,945)	$845,984
Income (Loss) from Discontinued Operations, net	85,708	(297,157)	382,865
Net Income (Loss)	$380,747	$(848,102)	$1,228,849

CNX currently consists of two principal business divisions: Exploration and Production (E&P) and Midstream. CNX's Midstream Division was the result of the Midstream Acquisition that occurred on January 3, 2018 (See Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information). Prior to the acquisition, CNX accounted for its interests in CNX Gathering and CNXM as an equity-method investment which is how it appears in the 2017 and 2016 analysis.

The principal activity of CNX, prior to the Midstream Acquisition, was to produce pipeline quality natural gas for sale primarily to gas wholesalers. The Company's reportable segments were Marcellus Shale, Utica Shale, Coalbed Methane, and Other Gas.

CNX had a total company earnings from continuing operations before income tax of $119 million for the year ended December 31, 2017, compared to a loss from continuing operations before income tax of $585 million for the year ended December 31, 2016. Included in the 2017 earnings from continuing operations before income tax was an unrealized gain on commodity derivative instruments of $248 million and a gain on sale of assets of $188 million, partially offset by $138 million of expense relating to the impairment in carrying value of Knox Energy LLC and Coalfield Pipeline Company (collectively, "Knox Energy"). See Note 1 - Significant Accounting Policies in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information. Included in the 2016 net loss from continuing operations before income tax was an unrealized loss on commodity derivative instruments of $386 million, partially offset by a gain on sale of assets of $14 million.

Natural gas, NGLs, and oil revenue was $1,125 million for the year ended December 31, 2017 compared to $793 million for the year ended December 31, 2016. The increase was primarily due to the 3.2% increase in total sales volumes.

Sales volumes, average sales price (including the effects of derivative instruments), and average costs for active operations in the period-to-period comparison were as follows:

	For the Years Ended December 31,			
	2017	**2016**	**Variance**	**Percent Change**
Sales Volume (Bcfe)	407.2	394.4	12.8	3.2 %
Average Sales Price (per Mcfe)	$2.66	$2.63	$0.03	1.1 %
Lease Operating Expense	0.22	0.24	(0.02)	(8.3)%
Production, Ad Valorem, and Other Fees	0.07	0.08	(0.01)	(12.5)%
Transportation, Gathering and Compression	0.94	0.95	(0.01)	(1.1)%
Depreciation, Depletion and Amortization (DD&A)	1.00	1.05	(0.05)	(4.8)%
Average Costs (per Mcfe)	$2.23	$2.32	$(0.09)	(3.9)%

Average Margin	$0.43	$0.31	$0.12	38.7 %

The increase in average sales price was primarily the result of the $0.67 per Mcf increase in general natural gas market prices in the Appalachian basin during the 2017 period and the $0.08 per Mcfe increase in the uplift from NGLs and condensate sales volumes when excluding the impact of hedging, partially offset by the $0.81 per Mcf decrease in the realized (loss) gain on commodity derivative instruments related to the Company's hedging program.

Changes in the average costs per Mcfe were primarily related to the following items:

- Depreciation, depletion, and amortization decreased on a per-unit basis primarily due to a reduction in Marcellus rates as a result of an increase in the Company's Marcellus reserves. See Note 10 - Property, Plant, and Equipment in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional details.
- Lease operating expense decreased on a per unit basis due to a decrease in well tending costs and salt water disposal costs, as well as a decrease in both Company operated and joint venture operated repairs and maintenance costs.

The following table presents a breakout of net liquid and natural gas sales information to assist in the understanding of the Company's natural gas production and sales portfolio.

	For the Years Ended December 31,			
in thousands (unless noted)	**2017**	**2016**	**Variance**	**Percent Change**
LIQUIDS				
NGLs:				
Sales Volume (MMcfe)	38,736	40,260	(1,524)	(3.8)%
Sales Volume (Mbbls)	6,456	6,710	(254)	(3.8)%
Gross Price ($/Bbl)	$24.18	$14.52	$9.66	66.5 %
Gross Revenue	$156,132	$97,580	$58,552	60.0 %
Oil:				
Sales Volume (MMcfe)	421	410	11	2.7 %
Sales Volume (Mbbls)	70	68	2	2.9 %
Gross Price ($/Bbl)	$45.36	$36.90	$8.46	22.9 %
Gross Revenue	$3,179	$2,521	$658	26.1 %
Condensate:				
Sales Volume (MMcfe)	3,116	4,964	(1,848)	(37.2)%
Sales Volume (Mbbls)	519	828	(309)	(37.3)%
Gross Price ($/Bbl)	$39.54	$27.48	$12.06	43.9 %
Gross Revenue	$20,531	$22,748	$(2,217)	(9.7)%
GAS				
Sales Volume (MMcf)	364,893	348,753	16,140	4.6 %
Sales Price ($/Mcf)	$2.59	$1.92	$0.67	34.9 %
Gross Revenue	$945,382	$670,823	$274,559	40.9 %
Hedging Impact ($/Mcf)	$(0.11)	$0.70	$(0.81)	(115.7)%
(Loss) Gain on Commodity Derivative Instruments - Cash Settlement	$(41,174)	$245,212	$(286,386)	(116.8)%

Selling, General and Administrative

SG&A costs include costs such as overhead, including employee wages and benefit costs, short-term incentive compensation, costs of maintaining our headquarters, audit and other professional fees, and legal compliance expenses. SG&A costs also includes noncash equity-based compensation expense.

SG&A costs were $93 million for the year ended December 31, 2017, compared to $105 million for the year ended December 31, 2016. SG&A costs decreased due to a decrease in employee wages and benefit costs in 2017 related to a reduction in headcount as well as a decrease in equity-based compensation expense.

Unallocated Expense
Certain costs and expenses such as other expense, gain on sale of assets related to non-core assets, loss on debt extinguishment and income taxes are unallocated expenses and therefore are excluded from the per unit costs above as well as segment reporting. Below is a summary of these costs and expenses:

Other Expense

	For the Years Ended December 31,			
(in millions)	**2017**	**2016**	**Variance**	**Percent Change**
Other Income				
Right of Way Sales	$2	$15	$ (13)	(86.7)%
Royalty Income	10	10	—	— %
Interest Income	9	—	9	100.0 %
Other	6	4	2	50.0 %
Total Other Income	$27	$29	$ (2)	(6.9)%
Other Expense				
Professional Services	$6	$7	$ (1)	(14.3)%
Bank Fees	13	13	—	— %
Other Land Rental Expense	6	5	1	20.0 %
Other Corporate Expense	6	9	(3)	(33.3)%
Total Other Expense	$31	$34	$ (3)	(8.8)%
Total Other Expense	$4	$5	$ (1)	(20.0)%

Gain on Sale of Assets

CNX recognized a gain on sale of assets of $188 million in the year ended December 31, 2017 compared to a gain of $14 million in the year ended December 31, 2016. The $174 million increase was primarily due to sale of approximately 22,000 acres of surface land in Colorado, the sale of approximately 7,500 net undeveloped acres of the Marcellus Shale in Pennsylvania, the sale of approximately 11,100 net undeveloped acres of the Marcellus and Utica Shale in Pennsylvania, and the sale of approximately 6,300 net undeveloped acres of the Utica-Point Pleasant Shale in Ohio in the year ended December 31, 2017. No individually significant transactions occurred in the year ended December 31, 2016. See Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Loss on Debt Extinguishment

Loss on debt extinguishment of $2 million was recognized in the year ended December 31, 2017 due to the purchase of a portion of the 5.875% senior notes due in April 2022 at an average price equal to 99.5% of the principal amount, the redemption of the 8.25% senior notes due in April 2020 at a call price equal to 101.375% of the principal amount, and the redemption of the 6.375% senior notes due in March 2021 at a call price equal to 102.125% of the principal amount. See Note 14 - Long-Term Debt in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Income Taxes

The effective income tax rate for continuing operations was (148.9)% for the year ended December 31, 2017, compared to 6.0 % for the year ended December 31, 2016. During the year ended December 31, 2016, CNX settled a

Federal audit of the years 2010-2013 and received a favorable private letter ruling from the IRS related to bonus depreciation. Overall, the Company received approximately $21 million in refunds during 2016. Some of the factors contributing to the refunds received during 2016 put pressure on deferred tax assets related to alternative minimum tax credits. As management could not demonstrate sufficient positive evidence to ensure realizability of these assets, the Company recorded a valuation allowance of $167 million at December 31, 2016 on alternative minimum tax credits as well as an additional $38 million valuation allowance was recorded at December 31, 2016 against state deferred tax assets, as well as federal charitable contributions and foreign tax credit carry-forwards.

On December 22, 2017, the United States enacted the Tax Cuts and Jobs Act (the "Act") which, among other things, lowered the U.S. Federal tax rate from 35% to 21%, repealed the corporate alternative minimum tax, and provided for a refund of previously accrued alternative minimum tax credits. The Company recorded a net tax benefit to reflect the impact of the Act as of December 31, 2017, as it is required to reflect the change in the period in which the law is enacted. Largely, the benefits recorded in the 2017 period related to tax reform are in recognition of the revaluation of deferred tax assets and liabilities, a benefit of $115 million, and the benefit for reversal of valuation allowance previously recorded against alternative minimum tax credits which are now refundable, a benefit of $154 million.

See Note 8 - Income Taxes in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

	For the Years Ended December 31,			
	2017	**2016**	**Variance**	**Percent Change**
Total Company Earnings (Loss) Before Income Tax	$119	$(585)	$704	(120.3)%
Income Tax Benefit	$(176)	$(34)	$(142)	417.6 %
Effective Income Tax Rate	(148.9)%	6.0 %	(154.9)%	

TOTAL E&P DIVISION ANALYSIS for the year ended December 31, 2017 compared to the year ended December 31, 2016:

The E&P division had a loss from continuing operations before income tax of $63 million for the year ended December 31, 2017 compared to a loss from continuing operations before income tax of $594 million for the year ended December 31, 2016. Variances by individual operating segment are discussed below.

	For the Year Ended December 31, 2017					Difference to Year Ended December 31, 2016				
(in millions)	Marcellus	Utica	CBM	Other Gas	Total	Marcellus	Utica	CBM	Other Gas	Total
Natural Gas, NGLs and Oil Revenue	$646	$217	$209	$53	$1,125	$231	$54	$34	$13	$332
(Loss) Gain on Commodity Derivative Instruments	(30)	1	(10)	246	207	(177)	(28)	(62)	615	348
Purchased Gas Revenue	—	—	—	54	54	—	—	—	11	11
Other Operating Income	—	—	—	69	69	—	—	—	4	4
Total Revenue and Other Operating Income	616	218	199	422	1,455	54	26	(28)	643	695
Lease Operating Expense	32	19	25	13	89	(2)	(3)	—	(2)	(7)
Production, Ad Valorem, and Other Fees	15	5	7	2	29	(2)	—	1	(1)	(2)
Transportation, Gathering and Compression	256	45	64	18	383	28	(6)	(8)	(5)	9
Depreciation, Depletion and Amortization	222	84	83	23	412	11	(2)	(3)	(14)	(8)
Impairment of Exploration and Production Properties	—	—	—	138	138	—	—	—	138	138
Exploration and Production Related Other Costs	—	—	—	48	48	—	—	—	33	33
Purchased Gas Costs	—	—	—	53	53	—	—	—	10	10
Other Operating Expense	—	—	—	112	112	—	—	—	23	23
Selling, General and Administrative Costs	—	—	—	93	93	—	—	—	(11)	(11)
Total Operating Costs and Expenses	525	153	179	500	1,357	35	(11)	(10)	171	185
Interest Expense	—	—	—	161	161	—	—	—	(21)	(21)
Total E&P Division Costs	$525	$153	$179	$661	$1,518	$35	$(11)	$(10)	$150	$164
Earnings (Loss) from Continuing Operations Before Income Tax	$91	$65	$20	$(239)	$(63)	$19	$37	$(18)	$493	$531

MARCELLUS SEGMENT

The Marcellus segment had earnings from continuing operations before income tax of $91 million for the year ended December 31, 2017 compared to earnings from continuing operations before income tax of $72 million for the year ended December 31, 2016.

	For the Years Ended December 31,			
	2017	**2016**	**Variance**	**Percent Change**
Marcellus Gas Sales Volumes (Bcf)	209.7	186.8	22.9	12.3 %
NGLs Sales Volumes (Bcfe)*	27.6	23.5	4.1	17.4 %
Condensate Sales Volumes (Bcfe)*	2.1	2.2	(0.1)	(4.5)%
Total Marcellus Sales Volumes (Bcfe)*	239.4	212.5	26.9	12.7 %
Average Sales Price - Gas (per Mcf)	$2.50	$1.87	$0.63	33.7 %
(Loss) Gain on Commodity Derivative Instruments - Cash Settlement- Gas (per Mcf)	$(0.14)	$0.79	$(0.93)	(117.7)%
Average Sales Price - NGLs (per Mcfe)*	$3.96	$2.38	$1.58	66.4 %
Average Sales Price - Condensate (per Mcfe)*	$6.44	$4.32	$2.12	49.1 %
Total Average Marcellus Sales Price (per Mcfe)	$2.57	$2.64	$(0.07)	(2.7)%
Average Marcellus Lease Operating Expenses (per Mcfe)	0.13	0.16	(0.03)	(18.8)%
Average Marcellus Production, Ad Valorem, and Other Fees (per Mcfe)	0.07	0.08	(0.01)	(12.5)%
Average Marcellus Transportation, Gathering and Compression Costs (per Mcfe)	1.07	1.07	—	— %
Average Marcellus Depreciation, Depletion and Amortization Costs (per Mcfe)	0.92	0.99	(0.07)	(7.1)%
Total Average Marcellus Costs (per Mcfe)	$2.19	$2.30	$(0.11)	(4.8)%
Average Margin for Marcellus (per Mcfe)	$0.38	$0.34	$0.04	11.8 %

*** NGLs and Condensate are converted to Mcfe at the rate of one barrel equals six Mcf based upon the approximate relative energy content of oil and natural gas, which is not indicative of the relationship of oil, NGLs, condensate, and natural gas prices.**

The Marcellus segment had natural gas, NGLs and oil revenue of $646 million for the year ended December 31, 2017compared to $415 million for the year ended December 31, 2016. The $231 million increase was primarily due to the 33.7% increase in the average gas sales price as well as the 12.7% increase in total Marcellus sales volumes in the period-to-period comparison. The increase in sales volumes was primarily due to the termination of the Marcellus joint venture with Noble Energy in the fourth quarter of 2016, which resulted in each party owning and operating a 100% interest in certain wells in two separate operating areas (See Note 10 - Property, Plant and Equipment in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional details) as well as additional wells being turned in line in the 2017 period.

The decrease in the total average Marcellus sales price was primarily the result of changes in the fair value of commodity derivative instruments resulting from the Company's hedging program. The notional amounts associated with these financial hedges represented approximately 177.6 Bcf of the Company's produced Marcellus gas sales volumes for the year ended December 31, 2017 at an average loss of $0.17 per Mcf. For the year ended December 31, 2016, these financial hedges represented approximately 160.8 Bcf at an average gain of $0.92 per Mcf. The $0.93 per Mcf change in the fair value of the commodity derivative instruments was offset, in part, by the $0.63 per Mcf increase in gas market prices, along with a $0.12 per Mcfe increase in the uplift from NGLs and condensate sales volumes, when excluding the impact of hedging.

Total operating costs and expenses for the Marcellus segment were $525 million for the year ended December 31, 2017 compared to $490 million for the year ended December 31, 2016. The increase in total dollars and decrease in unit costs for the Marcellus segment were due to the following items:

•Marcellus lease operating expense was $32 million for the year ended December 31, 2017 compared to $34 million for the year ended December 31, 2016. The decrease in total dollars was primarily due to a reduction in salt water disposal costs and equipment rental expense in the 2017 period. The decrease in unit costs was primarily due to the 12.7% increase in total Marcellus sales volumes, along with the decrease in total dollars described above.

•Marcellus production, ad valorem, and other fees were $15 million for the year ended December 31, 2017 compared to $17 million for the year ended December 31, 2016. The decrease in total dollars was primarily due to a change in production mix by state as a result of the termination of the Marcellus joint venture with Noble Energy, offset, in part, by the increase in average gas sales price. The decrease in unit costs was due to the decrease in total dollars described above, as well as the 12.7% increase in total Marcellus sales volumes.

•Marcellus transportation, gathering and compression costs were $256 million for the year ended December 31, 2017 compared to $228 million for the year ended December 31, 2016. The $28 million increase in total dollars was primarily related to an increase in the CNXM gathering fee due to the increase in total Marcellus sales volumes (See Note 25 - Related Party Transactions of the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information), and an increase in processing fees associated with NGLs primarily due to the 17.4% increase in NGL sales volumes.

•Depreciation, depletion and amortization costs attributable to the Marcellus segment were $222 million for the year ended December 31, 2017 compared to $211 million for the year ended December 31, 2016. These amounts included depletion on a unit of production basis of $0.91 per Mcf and $0.98 per Mcf, respectively. The remaining depreciation, depletion and amortization costs were either recorded on a straight-line basis or related to gas well closing.

UTICA SEGMENT

The Utica segment had earnings from continuing operations before income tax of $65 million for the year ended December 31, 2017 compared to earnings from continuing operations before income tax of $28 million for the year ended December 31, 2016.

	For the Years Ended December 31,			
	2017	2016	Variance	Percent Change
Utica Gas Sales Volumes (Bcf)	70.7	71.3	(0.6)	(0.8)%
NGLs Sales Volumes (Bcfe)*	11.1	16.7	(5.6)	(33.5)%
Oil Sales Volumes (Bcfe)*	0.2	—	0.2	100.0 %
Condensate Sales Volumes (Bcfe)*	1.0	2.8	(1.8)	(64.3)%
Total Utica Sales Volumes (Bcfe)*	83.0	90.8	(7.8)	(8.6)%
Average Sales Price - Gas (per Mcf)	$2.29	$1.52	0.77	50.7 %
Gain on Commodity Derivative Instruments - Cash Settlement- Gas (per Mcf)	$0.02	$0.41	(0.39)	(95.1)%
Average Sales Price - NGLs (per Mcfe)*	$4.20	$2.49	1.71	68.7 %
Average Sales Price - Oil (per Mcfe)*	$7.31	$—	7.31	100.0 %
Average Sales Price - Condensate (per Mcfe)*	$6.88	$4.78	2.10	43.9 %
Total Average Utica Sales Price (per Mcfe)	$2.63	$2.12	0.51	24.1 %
Average Utica Lease Operating Expenses (per Mcfe)	0.23	0.25	(0.02)	(8.0)%
Average Utica Production, Ad Valorem, and Other Fees (per Mcfe)	0.06	0.05	0.01	20.0 %
Average Utica Transportation, Gathering and Compression Costs (per Mcfe)	0.54	0.57	(0.03)	(5.3)%
Average Utica Depreciation, Depletion and Amortization Costs (per Mcfe)	1.02	0.94	0.08	8.5 %
Total Average Utica Costs (per Mcfe)	$1.85	$1.81	0.04	2.2 %
Average Margin for Utica (per Mcfe)	$0.78	$0.31	0.47	151.6 %

***NGLs and Condensate are converted to Mcfe at the rate of one barrel equals six mcf based upon the approximate relative energy content of oil and natural gas, which is not indicative of the relationship of oil, NGLs, condensate, and natural gas prices.**

The Utica segment had natural gas, NGLs and oil revenue of $217 million for the year ended December 31, 2017 compared to $163 million for the year ended December 31, 2016. The $54 million increase was primarily due to the

50.7% increase in average gas sales price, offset, in part, by the 8.6% decrease in total Utica sales volumes. The 7.8 Bcfe decrease in total Utica sales volumes primarily related to normal well declines in the wet gas joint venture production areas offset in part by increased production in the 100% CNX controlled dry Utica production areas resulting from the Company's 2017 capital investment.

The increase in the total average Utica sales price was primarily due to a $0.77 increase in average gas sales price, offset, in part, by the $0.39 per Mcf decrease in the gain on commodity derivative instruments in 2017. The notional amounts associated with these financial hedges represents approximately 39.8 Bcf of the Company's produced Utica gas sales volumes for the year ended December 31, 2017 at an average gain of $0.04 per Mcf. For the year ended December 31, 2016, these financial hedges represented approximately 31.6 Bcf at an average gain of $0.93 per Mcf.

Total operating costs and expenses for the Utica segment were $153 million for the year ended December 31, 2017 compared to $164 million for the year ended December 31, 2016. The decrease in total dollars and increase in unit costs for the Utica segment were due to the following items:

•Utica lease operating expense decreased to $19 million for the year ended December 31, 2017, compared to $22 million for the year ended December 31, 2016. The decrease in total dollars was due to a reduction in repairs and maintenance costs and lower production volumes. The decrease in unit costs was due to the decrease in repairs and maintenance cost and a shift in production mix to lower cost dry Utica production.

•Utica production, ad valorem, and other fees were $5 million for each of the years ended December 31, 2017 and December 31, 2016. The increase in unit costs was also due to the decrease in total Utica sales volumes.

•Utica transportation, gathering and compression costs were $45 million for the year ended December 31, 2017 compared to $51 million for the year ended December 31, 2016. The $6 million decrease in total dollars was primarily related to decreased gathering and processing fees associated with the decreased Utica NGLs and gas sales volumes. The decrease in unit costs was due to the decrease in total Utica sales volumes, predominantly in the wet areas that require additional processing offset, in part, by the increase in the lower cost dry Utica production.

•Depreciation, depletion and amortization costs attributable to the Utica segment were $84 million for the year ended December 31, 2017 compared to $86 million for the year ended December 31, 2016. These amounts included depletion on a unit of production basis of $1.01 per Mcf and $0.93 per Mcf, respectively. The remaining depreciation, depletion and amortization costs were either recorded on a straight-line basis or related to gas well closing.

COALBED METHANE (CBM) SEGMENT

The CBM segment had earnings from continuing operations before income tax of $20 million for the year ended December 31, 2017 compared to earnings from continuing operations before income tax of $38 million for the year ended December 31, 2016.

	For the Years Ended December 31,			
	2017	2016	Variance	Percent Change
CBM Gas Sales Volumes (Bcf)	65.4	69.0	(3.6)	(5.2)%
Average Sales Price - Gas (per Mcf)	$3.19	$2.53	$0.66	26.1 %
(Loss) Gain on Commodity Derivative Instruments - Cash Settlement- Gas (per Mcf)	$(0.15)	$0.76	$(0.91)	(119.7)%
Total Average CBM Sales Price (per Mcf)	$3.05	$3.29	$(0.24)	(7.3)%
Average CBM Lease Operating Expenses (per Mcf)	0.39	0.36	0.03	8.3 %
Average CBM Production, Ad Valorem, and Other Fees (per Mcf)	0.11	0.09	0.02	22.2 %
Average CBM Transportation, Gathering and Compression Costs (per Mcf)	0.98	1.04	(0.06)	(5.8)%
Average CBM Depreciation, Depletion and Amortization Costs (per Mcf)	1.26	1.25	0.01	0.8 %
Total Average CBM Costs (per Mcf)	$2.74	$2.74	$—	— %
Average Margin for CBM (per Mcf)	$0.31	$0.55	$(0.24)	(43.6)%

The CBM segment had natural gas sales of $209 million for the year ended December 31, 2017 compared to $175 million for the year ended December 31, 2016. The $34 million increase was due to a 26.1% increase in the average gas sales price, offset in part, by the 5.2% decrease in CBM gas sales volumes. The decrease in CBM sales volumes was primarily due to normal well declines and less drilling activity.

The total average CBM sales price decreased $0.24 per Mcf due primarily to changes in fair value of the commodity derivative instruments resulting from the Company's hedging program. The notional amounts associated with these financial hedges represented approximately 56.3 Bcf of the Company's produced CBM sales volumes for the year ended December 31, 2017 at an average loss of $0.17 per Mcf. For the year ended December 31, 2016, these financial hedges represented approximately 55.0 Bcf at an average gain of $0.95 per Mcf. The $0.91 per Mcf change in fair value of the commodity derivative instruments was offset, in part, by a $0.66 per Mcf increase in market prices.

Total operating costs and expenses for the CBM segment were $179 million for the year ended December 31, 2017 compared to $189 million for the year ended December 31, 2016. The decrease in total dollars was due to the following items:

•CBM lease operating expense remained consistent at $25 million for the years ended December 31, 2017 and December 31, 2016. The increase in unit costs was due to the decrease in CBM gas sales volumes.

•CBM production, ad valorem, and other fees were $7 million for the year ended December 31, 2017 compared to $6 million for the year ended December 31, 2016. The $1 million increase was due to an increase in severance tax expense resulting from the increase in the average gas sales price, partially offset by the decrease in production volumes. Unit costs were negatively impacted by the increase in total average gas sales price which was offset, in part, by the decrease in CBM gas sales volumes.

•CBM transportation, gathering and compression costs were $64 million for the year ended December 31, 2017 compared to $72 million for the year ended December 31, 2016. The $8 million decrease was primarily related to a decrease in repairs and maintenance expense and power fees resulting from cost cutting measures implemented by management as well as a decrease in utilized firm transportation expense resulting from a decrease in CBM gas sales volumes. Unit costs were also positively impacted by the decrease in total dollars which was offset, in part, by the decrease in CBM gas sales volumes.

•Depreciation, depletion and amortization costs attributable to the CBM segment were $83 million for the year ended December 31, 2017 compared to $86 million for the year ended December 31, 2016. These amounts included depletion on a unit of production basis of $0.78 per Mcf and $0.82 per Mcf, respectively. The remaining depreciation, depletion and amortization costs were either recorded on a straight-line basis or related to gas well closing.

OTHER GAS SEGMENT

The Other Gas segment had a loss from continuing operations before income tax of $239 million for the year ended December 31, 2017 compared to a loss from continuing operations before income tax of $732 million for the year ended December 31, 2016.

	For the Years Ended December 31,			
	2017	2016	Variance	Percent Change
Other Gas Sales Volumes (Bcf)	19.2	21.7	(2.5)	(11.5)%
Oil Sales Volumes (Bcfe)*	0.2	0.4	(0.2)	(50.0)%
Total Other Sales Volumes (Bcfe)*	19.4	22.1	(2.7)	(12.2)%
Average Sales Price - Gas (per Mcf)	$2.69	$1.79	$0.90	50.3 %
(Loss) Gain on Commodity Derivative Instruments - Cash Settlement- Gas (per Mcf)	$(0.14)	$0.75	$(0.89)	(118.7)%
Average Sales Price - Oil (per Mcfe)*	$7.75	$6.23	$1.52	24.4 %
Total Average Other Sales Price (per Mcfe)	$2.62	$2.61	$0.01	0.4 %
Average Other Lease Operating Expenses (per Mcfe)	0.63	0.69	(0.06)	(8.7)%
Average Other Production, Ad Valorem, and Other Fees (per Mcfe)	0.12	0.12	—	— %
Average Other Transportation, Gathering and Compression Costs (per Mcfe)	0.90	1.07	(0.17)	(15.9)%
Average Other Depreciation, Depletion and Amortization Costs (per Mcfe)	1.05	1.49	(0.44)	(29.5)%
Total Average Other Costs (per Mcfe)	$2.70	$3.37	$(0.67)	(19.9)%
Average Margin for Other (per Mcfe)	$(0.08)	$(0.76)	$0.68	89.5 %

***Oil is converted to Mcfe at the rate of one barrel equals six Mcf based upon the approximate relative energy content of oil and natural gas, which is not indicative of the relationship of oil and natural gas prices.**

The Other Gas segment includes activity not assigned to the Marcellus, Utica, or CBM segments. This segment also includes purchased gas activity, unrealized gain or loss on commodity derivative instruments, exploration and production related other costs, impairment of exploration and production properties and other operational activity not assigned to a specific segment.

Other Gas sales volumes are primarily related to shallow oil and gas production. Although not discussed in this section, CNX sold substantially all its Other Gas assets in the 2018 period. Natural gas, NGLs and oil revenue related to the Other Gas segment were $53 million for the year ended December 31, 2017 compared to $40 million for the year ended December 31, 2016. The increase in natural gas and oil revenue resulted from the $0.90 per Mcf increase in average gas sales price. Total exploration and production costs related to these other sales were $56 million for the year ended December 31, 2017 compared to $78 million for the year ended December 31, 2016. The decrease was primarily due to a decrease in depreciation, depletion and amortization costs as a result of certain assets becoming fully depreciated in 2017 as well as the sale of Knox Energy in the second quarter of 2017 (See Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information).

The Other Gas segment recognized an unrealized gain on commodity derivative instruments of $248 million as well as cash settlements paid of $2 million for the year ended December 31, 2017. For the year ended December 31, 2016, the Company recognized an unrealized loss on commodity derivative instruments of $386 million as well as cash settlements received of $17 million. The unrealized gain/loss on commodity derivative instruments represented changes in the fair value of all of the Company's existing commodity hedges on a mark-to-market basis.

Purchased gas volumes represent volumes of gas purchased at market prices from third-parties and then resold in order to fulfill contracts with certain customers. Purchased gas revenue was $54 million for the year ended December 31, 2017 compared to $43 million for the year ended December 31, 2016. Purchased gas costs were $53 million for the year ended December 31, 2017 compared to $43 million for the year ended December 31, 2016. The period-to-period increase in purchased gas revenue was primarily due to the increase market prices, as well as the increase in purchased gas sales volumes.

	For the Years Ended December 31,			
	2017	2016	Variance	Percent Change
Purchased Gas Sales Volumes (in billion cubic feet)	22.0	21.7	0.3	1.4 %
Average Sales Price (per Mcf)	$2.44	$1.99	$ 0.45	22.6%
Average Cost (per Mcf)	$2.39	$1.97	$ 0.42	21.3%

Other operating income was $69 million for each of the years ended December 31, 2017 compared to $65 million for the year ended December 31, 2016. The $4 million increase was primarily due to the following items:

	For the Years Ended December 31,			
(in millions)	2017	2016	Variance	Percent Change
Water Income	$5	$1	$ 4	400.0 %
Gathering Income	11	11	—	— %
Equity in Earnings of Affiliates	50	53	(3)	(5.7)%
Other	3	—	3	100.0 %
Total Other Operating Income	$69	$65	$ 4	6.2 %

- Water Income increased $4 million due to increased sales of freshwater to third-parties for hydraulic fracturing.
- Equity in Earnings of Affiliates decreased $3 million primarily due to a decrease in earnings from Buchanan Generation, LLC.

Impairment of Exploration and Production Properties of $138 million for the year ended December 31, 2017 related to an impairment in the carrying value of Knox Energy in the first quarter of 2017. See Note 1 - Significant Accounting Policies in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information. No such impairments occurred in 2016.

Exploration and production related other costs were $48 million for the year ended December 31, 2017 compared to $15 million for the year ended December 31, 2016. The $33 million increase is due to the following items:

	For the Years Ended December 31,			
(in millions)	2017	2015	Variance	Percent Change
Lease Expiration Costs	$40	$7	$ 33	471.4 %
Land Rentals	4	4	—	100.0 %
Permitting Expense	1	2	(1)	(50.0)%
Other	3	2	1	50.0 %
Total Exploration and Production Related Other Costs	$48	$15	$ 33	220.0 %

- Lease Expiration Costs relate to leases where the primary term expired or will expire within the next 12 months. The $33 million increase in the period-to-period comparison is due to an increase in the number of leases that were allowed to expire in the year ended December 31, 2017, or would expire within the next 12 months thereafter, because they were no longer in the Company's future drilling plan. Additionally, approximately $10 million of the $33 million increase was associated with leases which have ceased production.

Other operating expense was $112 million for the year ended December 31, 2017 compared to $89 million for the year ended December 31, 2016. The $23 million increase in the period-to-period comparison was made up of the following items:

	For the Years Ended December 31,			
(in millions)	2017	2016	Variance	Percent Change
Idle Rig Expense	$41	$33	$ 8	24.2 %
Unutilized Firm Transportation and Processing Fees	50	37	13	35.1 %
Litigation Settlements	3	1	2	200.0 %
Severance Expense	1	1	—	— %
Insurance Expense	3	3	—	— %
Other	14	14	—	— %
Total Other Operating Expense	$112	$89	$ 23	25.8 %

- Idle Rig Expense increased $8 million due to the temporary idling of some of the Company's natural gas rigs. Additionally, the total idle rig expense increased in the period-to-period comparison due to a settlement that was reached with a former joint-venture partner that resulted in CNX recording additional expense.
- Unutilized Firm Transportation and Processing Fees represent pipeline transportation capacity obtained to enable gas production to flow uninterrupted as sales volumes increase, as well as additional processing capacity for NGLs. The increase in the period-to-period comparison was primarily due to the decrease in the utilization of capacity. The Company attempts to minimize this expense by releasing (selling) unutilized firm transportation capacity to other parties when possible and when beneficial. The revenue received when this capacity is released (sold) is included in Gathering Income in other operating income above.

Selling, General and Administrative

SG&A costs represent direct charges for the management and operation of CNX's E&P division. SG&A costs were $93 million for the year ended December 31, 2017 compared to $104 million for the year ended December 31, 2016. Refer to the discussion of total company SG&A costs contained in the section "Net Income (Loss)" of this Form 10-K for a detailed cost explanation.

Interest Expense

Interest expense of $161 million was recognized in the year ended December 31, 2017 compared to $182 million in the year ended December 31, 2016. The $21 million decrease was primarily due to the redemption of each of the 8.25% senior notes due in April 2020 and the 6.375% senior notes due in March 2021 and the purchase of a portion of the 5.875% senior notes due in April 2022 in the year ended December 31, 2017. See Note 14 - Long-Term Debt in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Critical Accounting Policies

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make judgments, estimates and assumptions that affect reported amounts of assets and liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities in the Consolidated Financial Statements and at the date of the financial statements. See Note 1-Significant Accounting Policies in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion. We base our estimates on historical experience and on various other assumptions that we believe are reasonable under the circumstances, the results of which form the basis for making the judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. We evaluate our estimates on an on-going basis. Actual results could differ from those estimates upon subsequent resolution of identified matters. Management believes that the estimates utilized are reasonable. The following critical accounting policies are materially impacted by judgments, assumptions and estimates used in the preparation of the Consolidated Financial Statements.

Asset Retirement Obligations

Accounting for Asset Retirement Obligations requires that the fair value of an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The present value of the estimated asset retirement costs is capitalized as part of the carrying amount of the long-lived asset. Asset retirement obligations primarily relate to the closure of gas wells and the reclamation of land upon exhaustion of gas reserves. Changes in the variables used to calculate the liabilities can have a significant effect on the gas well closing liability. The amounts of assets and liabilities recorded are dependent upon a number of variables, including the estimated future retirement costs, estimated proved reserves, assumptions involving profit margins, inflation rates and the assumed credit-adjusted risk-free interest rate.

The Company believes that the accounting estimates related to asset retirement obligations are “critical accounting estimates” because the Company must assess the expected amount and timing of asset retirement obligations. In addition, the Company must determine the estimated present value of future liabilities. Future results of operations for any particular quarterly or annual period could be materially affected by changes in the Company’s assumptions.

Income Taxes

Deferred tax assets and liabilities are recognized using enacted tax rates for the estimated future tax effects of temporary differences between the book and tax basis of recorded assets and liabilities. Deferred tax assets are reduced by a valuation allowance if it is more likely than not that some portion of the deferred tax asset will not be realized. All available evidence, both positive and negative, must be considered in determining the need for a valuation allowance. At December 31, 2018, CNX had deferred tax liabilities in excess of deferred tax assets of approximately $304 million. At December 31, 2018, CNX had a valuation allowance of $94 million on deferred tax assets.

CNX evaluates all tax positions taken on the state and federal tax filings to determine if the position is more likely than not to be sustained upon examination. For positions that meet the more likely than not to be sustained criteria, an evaluation to determine the largest amount of benefit, determined on a cumulative probability basis that is more likely than not to be realized upon ultimate settlement is determined. A previously recognized tax position is reversed when it is subsequently determined that a tax position no longer meets the more likely than not threshold to be sustained. The evaluation of the sustainability of a tax position and the probable amount that is more likely than not is based on judgment, historical experience and on various other assumptions that we believe are reasonable under the circumstances. The results of these estimates, that are not readily apparent from other sources, form the basis for recognizing an uncertain tax liability. Actual results could differ from those estimates upon subsequent resolution of identified matters. CNX has $32 million of uncertain tax liabilities at December 31, 2018. See Note 8 - Income Taxes in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding the Company's uncertain tax liabilities.

The Company believes that accounting estimates related to income taxes are "critical accounting estimates" because the Company must assess the likelihood that deferred tax assets will be recovered from future taxable income and exercise judgment regarding the amount of financial statement benefit to record for uncertain tax positions. When evaluating whether or not a valuation allowance must be established on deferred tax assets, the Company exercises judgment in determining whether it is more likely than not (a likelihood of more than 50%) that some portion or all of the deferred tax assets will not be realized. The Company considers all available evidence, both positive and negative, to determine whether, based on the weight of the evidence, a valuation allowance is needed, including carrybacks, tax planning strategies and reversal of deferred tax assets and liabilities. In making the determination related to uncertain tax positions, the Company considers the amounts and probabilities of the outcomes that could be realized upon ultimate settlement of an uncertain tax position using the facts, circumstances and information available at the reporting date to establish the appropriate amount of financial statement benefit. To the extent that an uncertain tax position or valuation allowance is established or increased or decreased during a period, the Company must include an expense or benefit within tax expense in the income statement. Future results of operations for any particular quarterly or annual period could be materially affected by changes in the Company's assumptions.

Stock-Based Compensation

The fair value of each restricted stock unit awarded is equivalent to the closing market price of a share of the Company's stock on the date of the grant. The fair value of each performance share unit is determined by a Monte Carlo simulation method. The fair value of each stock option is determined using the Black-Scholes option pricing model. All outstanding performance stock options are fully vested.

The Company believes that the accounting estimates related to share-based compensation are "critical accounting estimates" because they may change from period-to-period based on changes in assumptions about factors affecting the ultimate payout of awards, including the number of awards to ultimately vest and the market price and volatility of the Company's common stock. Future results of operations for any particular quarterly or annual period could be materially affected by changes in the Company's assumptions. See Note 17 - Stock-Based Compensation in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding the Company's share-based compensation.

Contingencies

CNX is currently involved in certain legal proceedings. The Company has accrued our estimate of the probable costs for the resolution of these claims. This estimate has been developed in consultation with legal counsel involved in the defense of these matters and is based upon the nature of the lawsuit, progress of the case in court, view of legal counsel, prior experience in similar matters, and management's intended response. Future results of operations for any particular quarter or annual period could be materially affected by changes in our assumptions or the outcome of these proceedings. Legal fees associated with defending these various lawsuits and claims are expensed when incurred.

The Company believes that the accounting estimates related to contingencies are "critical accounting estimates" because the Company must assess the probability of loss related to contingencies. In addition, the Company must determine the estimated present value of future liabilities. Future results of operations for any particular quarterly or annual period could be materially affected by changes in the Company's assumptions. See Note 22 - Commitments and Contingent Liabilities in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for more information.

Derivative Instruments

CNX enters into financial derivative instruments to manage exposure to natural gas price volatility. We measure every derivative instrument at fair value and record them on the balance sheet as either an asset or liability. Changes in fair value of derivatives are recorded currently in earnings unless special hedge accounting criteria are met. For derivatives designated as fair value hedges, the changes in fair value of both the derivative instrument and the hedged item are recorded in earnings. Prior to December 31, 2014, the effective portions of changes in fair value of derivatives designated as cash flow hedges were reported in other comprehensive income or loss and reclassified into earnings in the same period or periods which the forecasted transaction affected earnings. The ineffective portions of hedges were recognized in earnings in the current year.

The Company believes that the accounting estimates related to derivative instruments are "critical accounting estimates" because the Company's financial condition and results of operations can be significantly impacted by changes in the market value of the Company's derivative instruments due to the volatility of natural gas prices. Future results of operations for any particular quarterly or annual period could be materially affected by changes in the Company’s assumptions.

Natural Gas, NGL, Condensate and Oil Reserve ("Natural Gas Reserve") Values

Proved oil and gas reserves, as defined by SEC Regulation S-X Rule 4-10, are those quantities of oil and natural gas which, by analysis of geoscience 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 prior to the time at which 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.

There are numerous uncertainties inherent in estimating quantities and values of economically recoverable natural gas reserves, including many factors beyond our control. As a result, estimates of economically recoverable natural gas reserves are by their nature uncertain. Information about our reserves consists of estimates based on engineering, economic and geological data assembled and analyzed by our staff. Our natural gas reserves are reviewed by independent experts each year. Some of the factors and assumptions which impact economically recoverable reserve estimates include:

- geological conditions;
- historical production from the area compared with production from other producing areas;
- the assumed effects of regulations and taxes by governmental agencies;
- assumptions governing future prices; and
- future operating costs.

Each of these factors may in fact vary considerably from the assumptions used in estimating reserves. For these reasons, estimates of the economically recoverable quantities of gas attributable to a particular group of properties, and classifications of these reserves based on risk of recovery and estimates of future net cash flows, may vary substantially. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and these variances may be material. See "Risk Factors" in Item 1A of this Form 10-K for a discussion of the uncertainties in estimating our reserves.

The Company believes that the accounting estimate related to oil and gas reserves is a “critical accounting estimate” because the Company must periodically reevaluate proved reserves along with estimates of future production rates, production costs and the estimated timing of development expenditures. Future results of operations and strength of the balance sheet for any particular quarterly or annual period could be materially affected by changes in the Company’s assumptions. See "*Impairment of Long-lived Assets*" below for additional information regarding the Company’s oil and gas reserves.

Impairment of Long-lived Assets

The carrying values of the Company's proved oil and gas properties are reviewed for impairment whenever events or changes in circumstances indicate that a property’s carrying amount may not be recoverable. Impairment tests require that the Company first compare future undiscounted cash flows by asset group to their respective carrying values. If the carrying amount exceeds the estimated undiscounted future cash flows, a reduction of the carrying amount of the natural gas properties to their estimated fair values is required, which is determined based on discounted cash flow techniques using a market-specific weighted average cost of capital.

In February 2017, the Company approved a plan to sell subsidiaries Knox Energy LLC and Coalfield Pipeline Company (collectively, Knox). As part of the required evaluation under the held for sale guidance, Knox's book value was evaluated, and it was determined that the approximate fair value less costs to sell Knox was less than the carrying value of the net assets to be sold. The resulting impairment of $137,865 was included in Impairment of Exploration and Production Properties in the Consolidated Statements of Income. See Note 1 - Significant Accounting Policies in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for more information.

There were no other impairments related to proved properties in the years ended December 31, 2018, 2017 or 2016.

CNX evaluates capitalized costs of unproved gas properties for recoverability on a prospective basis. Indicators of potential impairment include potential shifts in business strategy, overall economic factors and historical experience. If it is determined that the properties will not yield proved reserves, the related costs are expensed in the period the determination is made. There were no impairments related to unproved properties in the years ended December 31, 2018, 2017 or 2016.

The Company believes that the accounting estimates related to the impairment of long-lived assets are “critical accounting estimates” because the fair value estimation process requires considerable judgment and determining the fair value is sensitive to changes in assumptions impacting management’s estimates of future financial results. In addition, the Company must determine the estimated undiscounted future cash flows. The Company believes the estimates and assumptions used in estimating the fair value are reasonable and appropriate; however, different assumptions and estimates could materially impact the calculated fair value and the resulting determinations about the impairment of long-lived assets which could materially impact the Company’s results of operations and financial position. Additionally, future estimates may differ materially from current estimates and assumptions.

Impairment of Goodwill

Goodwill is not amortized, but rather it is evaluated for impairment annually during the fourth quarter, or more frequently if recent events or prevailing conditions indicate it is more likely than not that the fair value of a reporting unit is less than its carrying value. This determination includes estimating the fair value using both income and market approaches. The income approach requires management to estimate a number of factors for a reporting unit, including projected future operating results, economic projections, anticipated future cash flows and discount rates. The market approach estimates fair value using comparable marketplace fair value data from within a comparable industry grouping. CNX goodwill is allocated to one reporting unit within the Midstream segment.

The determination of the fair value requires us to make significant estimates and assumptions. These estimates and assumptions primarily include but are not limited to: the selection of appropriate peer group companies; control premiums appropriate for acquisitions in the industries in which we compete; discount rates; terminal growth rates; and forecasts of revenue, operating income, depreciation and amortization and capital expenditures. Although we believe our estimates of fair value are reasonable, actual financial results could differ from those estimates due to the inherent uncertainty involved in making such estimates. Changes in assumptions concerning future financial results or other underlying assumptions could have a significant impact on either the fair value of the reporting unit, the amount of any goodwill impairment charge, or both.

The Company performed its annual goodwill impairment test during the fourth quarter of 2018 and concluded that goodwill was not impaired.

The Company believes that the accounting estimates related to goodwill are “critical accounting estimates” because the fair value estimation process requires considerable judgment and determining the fair value is sensitive to changes in assumptions impacting management’s estimates of future financial results. The fair value estimation process requires considerable judgment and determining the fair value is sensitive to changes in assumptions impacting management’s estimates of future financial results as well as other assumptions such as movement in the Company's stock price, weighted-average cost of capital, terminal growth rates, changes in the business climate, unanticipated changes in the competitive environment, adverse legal or regulatory actions or developments, changes in capital structure, cost of debt, interest rates, capital expenditure levels, operating cash flows, or market capitalization and industry multiples. The Company believes the estimates and assumptions used in estimating the fair value are reasonable and appropriate; however, different assumptions and estimates could materially impact the calculated fair value and the resulting determinations about goodwill impairment which could materially impact the Company’s results of operations and financial position. Additionally, future estimates may differ materially from current estimates and assumptions.

Impairment of Definite-lived Intangible Assets

Definite-lived intangible assets are amortized on a straight-line basis over their estimated economic lives and they are reviewed for impairment when indicators of impairment are present. Impairment tests require that the Company first compare future undiscounted cash flows to their respective carrying values. If the carrying amount exceeds the estimated undiscounted future cash flows, a reduction of the carrying amount of the asset to its estimated fair value is required.

In May 2018, CNX determined that the carrying value of a portion of the customer relationship intangible assets that were acquired in connection with the Midstream acquisition exceeded their fair value in conjunction with the Asset Exchange Agreement with HG Energy II Appalachia, LLC (See Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for more information). CNX recognized an impairment on this intangible asset of $18,650, which is included in Impairment of Other Intangible Assets in the Consolidated Statements of Income.

The Company believes that the accounting estimates related to the impairment of definite-lived intangible assets are “critical accounting estimates” because the fair value estimation process requires considerable judgment and determining the fair value is sensitive to changes in assumptions impacting management’s estimates of future financial results. The Company believes the estimates and assumptions used in estimating the fair value are reasonable and appropriate; however, different assumptions and estimates could materially impact the calculated fair value and the resulting determinations about the impairment of definite-lived intangible assets which could materially impact the Company’s results of operations and financial position. Additionally, future estimates may differ materially from current estimates and assumptions.

Business Combinations

Accounting for the acquisition of a business requires the identifiable assets and liabilities acquired to be recorded at fair value. The most significant assumptions in a business combination include those used to estimate the fair value of the oil and gas properties acquired. The fair value of proved natural gas properties is determined using a risk-adjusted after-tax discounted cash flow analysis based upon significant assumptions including commodity prices; projections of estimated quantities of reserves; projections of future rates of production; timing and amount of future development and operating costs; projected reserve recovery factors; and a weighted average cost of capital.

The Company utilizes the guideline transaction method to estimate the fair value of unproved properties acquired in a business combination which requires the Company to use judgment in considering the value per undeveloped acre in recent comparable transactions to estimate the value of unproved properties.

The estimated fair value of midstream facilities and equipment, generally consisting of pipeline systems and compression stations, is estimated using the cost approach, which incorporates assumptions about the replacement costs for similar assets, the relative age of assets and any potential economic or functional obsolescence.

The fair values of the intangible assets are estimated using the multi-period excess earnings model which estimates revenues and cash flows derived from the intangible asset and then deducts portions of the cash flow that can be attributed to supporting assets otherwise recognized. The Company’s intangible assets are comprised of customer relationships.

The Company believes that the accounting estimates related to business combinations are “critical accounting estimates” because the Company must, in determining the fair value of assets acquired, make assumptions about future commodity prices; projections of estimated quantities of reserves; projections of future rates of production; projections regarding the timing and amount of future development and operating costs; and projections of reserve recovery factors, per acre values of undeveloped property, replacement cost of and future cash flows from midstream assets, cash flow from customer relationships and non-compete agreements and the pre and post modification value of stock based awards. Different assumptions may result in materially different values for these assets which would impact the Company’s financial position and future results of operations.

Liquidity and Capital Resources

CNX generally has satisfied its working capital requirements and funded its capital expenditures and debt service obligations with cash generated from operations and proceeds from borrowings. On March 8, 2018, CNX amended and restated its senior secured revolving credit facility (the Credit Facility), which increased lenders' commitments from $1.5 billion to $2.1 billion with an accordion feature that allows the Company to increase the commitments to $3.0 billion. The initial borrowing base increased from $2.0 billion to $2.5 billion, and the letters of credit aggregate sub-limit remained unchanged at $650 million. Effective August 20, 2018, as part of the semi-annual redetermination, the borrowing base was reduced to $2.1 billion primarily based on the sale of substantially all of CNX's Ohio Utica Joint Venture Assets and shallow oil and gas assets (See Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information). There was no change to the commitments amount. The Credit Facility matures on March 8, 2023, provided that if the aggregate principal amount of our existing 5.875% Senior Notes due in April 2022 and certain other publicly traded debt securities outstanding 91 days prior to the earliest maturity of such debt (such date, the "Springing Maturity Date") is greater than $500 million, then the Credit Facility will mature on the Springing Maturity Date.

The Credit Facility is secured by substantially all of the assets of CNX and certain of its subsidiaries, excluding CNXM. Fees and interest rate spreads are based on the percentage of facility utilization, measured quarterly. Availability under the Credit Facility is limited to a borrowing base, which is determined by the lenders' syndication agent and approved by the required number of lenders in good faith by calculating a value of CNX's proved natural gas reserves.

The Credit Facility contains a number of affirmative and negative covenants that include, among others, covenants that, except in certain circumstances, limit the Company and the subsidiary guarantors' ability to create, incur, assume or suffer to exist indebtedness, create or permit to exist liens on properties, dispose of assets, make investments, purchase or redeem CNX common stock, pay dividends, merge with another corporation and amend the senior unsecured notes. The Company must also mortgage 80% of the value of its proved reserves and 80% of the value of its proved developed producing reserves, in each case, which are included in the borrowing base, maintain applicable deposit, securities and commodities accounts with the lenders or affiliates thereof, and enter into control agreements with respect to such applicable accounts.

The Credit Facility also requires that CNX maintain a maximum net leverage ratio of no greater than 4.00 to 1.00, which is calculated as the ratio of debt less cash on hand to consolidated EBITDA, measured quarterly. CNX must also maintain a minimum current ratio of no less than 1.00 to 1.00, which is calculated as the ratio of current assets, plus revolver availability, to current liabilities, excluding short-term borrowings under the revolver, measured quarterly. The calculation of all of the ratios exclude CNXM. CNX was in compliance of all financial covenants as of December 31, 2018.

At December 31, 2018, the Credit Facility had $612 million of borrowings outstanding and $198 million of letters of credit outstanding, leaving $1,290 million of unused capacity. From time to time, CNX is required to post financial assurances to satisfy contractual and other requirements generated in the normal course of business. Some of these assurances are posted to comply with federal, state or other government agencies' statutes and regulations. CNX sometimes uses letters of credit to satisfy these requirements and these letters of credit reduce the Company's borrowing facility capacity.

Uncertainty in the financial markets brings additional potential risks to CNX. These risks include declines in the Company's stock price, less availability and higher costs of additional credit, potential counterparty defaults, and commercial bank failures. Financial market disruptions may impact the Company's collection of trade receivables. As a result, CNX regularly monitors the creditworthiness of its customers and counterparties and manages credit exposure through payment terms, credit limits, prepayments and security. CNX believes that its current group of customers is financially sound and represents no abnormal business risk.

CNX believes that cash generated from operations, asset sales and the Company's borrowing capacity will be sufficient to meet the Company's working capital requirements, anticipated capital expenditures (other than major acquisitions), scheduled debt payments, anticipated dividend payments and to provide required letters of credit. Nevertheless, the ability of CNX to satisfy its working capital requirements, to service its debt obligations, to fund planned capital expenditures, or to pay dividends will depend upon future operating performance, which will be affected by prevailing economic conditions in the natural gas industry and other financial and business factors, some of which are beyond CNX's control.
In order to manage the market risk exposure of volatile natural gas prices in the future, CNX enters into various physical natural gas supply transactions with both gas marketers and end users for terms varying in length. CNX has also entered into various natural gas and NGL swap and option transactions, which exist parallel to the underlying physical transactions. The fair value of these contracts was a net asset of $99 million at December 31, 2018 and a net asset of $60 million at December 31, 2017. The Company has not experienced any issues of non-performance by derivative counterparties.

CNX frequently evaluates potential acquisitions. CNX has funded acquisitions with cash generated from operations and a variety of other sources, depending on the size of the transaction, including debt and equity financing. There can be no assurance that additional capital resources, including debt and equity financing, will be available to CNX on terms which CNX finds acceptable, or at all.

Cash Flows (in millions)

	For the Years Ended December 31,		
	2018	2017	Change
Cash provided by operating activities	$886	$649	$237
Cash used in investing activities	$(895)	$(222)	$(673)
Cash (used in) provided by financing activities	$(483)	$36	$(519)

Cash provided by operating activities changed in the period-to-period comparison primarily due to the following items:

- Net income increased $502 million in the period-to-period comparison.
- Adjustments to reconcile net income to cash provided by operating activities primarily consisted of a $624 million gain on previously held equity interest, a $488 million change in deferred income taxes, a $138 million decrease in impairment of exploration and production properties, a $130 million change in discontinued operations (See Note 5 - Discontinued Operations in the Notes to the Audited Consolidated Financial Statements included in Item 8 of this Form 10-K for more information), a $208 million net change in commodity derivative instruments, and a $52 million increase in the loss on debt extinguishment.

Cash used in investing activities changed in the period-to-period comparison primarily due to the following items:

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- Capital expenditures increased $483 million in the period-to-period comparison primarily due to increased expenditures in both the Marcellus and Utica Shale plays resulting from increased drilling and completions activity. Also contributing to the increase is CNXM's capital expenditures which were not included in 2017 due to the consolidation that occurred in 2018. See Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.
- In January 2018, CNX acquired Noble Energy's interest in CNX Gathering for a net payment of $299 million. See Note 6 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.
- Proceeds from the sale of assets increased $98 million primarily due to the 2018 sale of substantially all of the Ohio Utica Joint Venture Assets in the wet gas Utica Shale areas of Belmont, Guernsey, Harrison, and Noble counties along with the 2018 sale of substantially all of CNX's shallow oil and gas assets and certain CBM assets in Pennsylvania and West Virginia. This was partially offset by the 2017 sales of approximately 32,900 net undeveloped acres in Ohio, Pennsylvania, and West Virginia.

Cash (used in) provided by financing activities changed in the period-to-period comparison primarily due to the following items:

- In the year ended December 31,2018, there were $612 million of borrowings on the CNX credit facility.
- In the year ended December 31, 2018, CNX paid $955 million to repurchase all of the remaining 8.00% senior notes due April 2023 and $411 million of the 5.75% senior notes due in April 2022. CNXM also received proceeds of $394 million from long-term borrowings. In the year ended December 31, 2017, CNX paid $240 million to repurchase $144 million of the 5.75% senior notes due in April 2022 and the remaining 8.25% senior notes due in April 2020 and the 6.375% senior notes due in March 2021. See Note 14 - Long-Term Debt in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.
- In the years ended December 31, 2018 and 2017, CNX repurchased $382 million and $103 million, respectively, of its common stock on the open market.
- In the year ended December 31,2018, there were $66 million of net payments on the CNXM credit facility.
- In the year ended December 31,2018, there were $55 million in distributions to CNXM noncontrolling interest holders.
- In the year ended December 31, 2017, CNX received proceeds of $425 million related to the spin-off of its coal business. See Note 5 - Discontinued Operations in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.
- In the year ended December 31, 2018, there were $21 million in debt issuance and financing fees. These fees were nominal in the twelve months ended December 31, 2017.
- Financing activities of discontinued operations changed $32 million. See Note 5 - Discontinued Operations in the Notes to the Audited Consolidated Financial Statements included in Item 8 of this Form 10-K for more information.

The following is a summary of the Company's significant contractual obligations at December 31, 2018 (in thousands):

	Payments due by Year				
	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years	Total
Purchase Order Firm Commitments	$22,036	$1,155	$—	$—	$23,191
Gas Firm Transportation and Processing	198,352	406,924	358,820	1,034,145	1,998,241
Long-Term Debt	—	—	1,992,376	394,625	2,387,001
Interest on Long-Term Debt	133,124	266,248	129,454	65,000	593,826
Capital (Finance) Lease Obligations	6,997	13,299	—	—	20,296
Interest on Capital (Finance) Lease Obligations	1,252	989	—	—	2,241
Operating Lease Obligations	70,590	128,405	24,665	36,256	259,916
Long-Term Liabilities—Employee Related (a)	1,857	4,012	4,303	25,508	35,680
Other Long-Term Liabilities (b)	244,087	27,421	2,364	32,877	306,749
Total Contractual Obligations (c)	$678,295	$848,453	$2,511,982	$1,588,411	$5,627,141

(a) Employee related long-term liabilities include salaried retirement contributions and work-related injuries and illnesses.

(b) Other long-term liabilities include royalties and other long-term liability costs.

(c) The significant obligation table does not include obligations to taxing authorities due to the uncertainty surrounding the ultimate settlement of amounts and timing of these obligations.

Debt

At December 31, 2018, CNX had total long-term debt and capital lease obligations of $2,407 million outstanding, including the current portion of long-term debt of $7 million. This long-term debt consisted of:

- An aggregate principal amount of $1,294 million of 5.875% Senior Notes due in April 2022 plus $2 million of unamortized bond premium. Interest on the notes is payable April 15 and October 15 of each year. Payment of the principal and interest on the notes is guaranteed by most of CNX's subsidiaries but does not include CNXM.
- An aggregate principal amount of $612 million in outstanding borrowings under the CNX revolver.
- An aggregate principal amount of $400 million of 6.50% Senior Notes due in March 2026 issued by CNXM, less $5 million of unamortized bond discount. Interest on the notes is payable March 15 and September 15 of each year. Payment on the principal and interest on the notes is guaranteed by certain of CNXM's subsidiaries. CNX is not a guarantor of these notes.
- An aggregate principal amount of $84 million in outstanding borrowings under the CNXM revolver. CNX is not a guarantor of CNXM's revolving credit facility.
- An aggregate principal amount of $20 million of capital leases with a weighted average interest rate of 7.18% per annum.

Total Equity and Dividends

CNX had total equity of $5,082 million at December 31, 2018 compared to $3,900 million at December 31, 2017. See the Consolidated Statements of Stockholders' Equity in Item 8 of this Form 10-K for additional details.

The declaration and payment of dividends by CNX is subject to the discretion of CNX's Board of Directors, and no assurance can be given that CNX will pay dividends in the future. CNX's Board of Directors determines whether dividends will be paid quarterly. CNX suspended its quarterly dividend in March 2016 to further reflect the Company's increased emphasis on growth. The determination to pay dividends in the future will depend upon, among other things, general business conditions, CNX's financial results, contractual and legal restrictions regarding the payment of dividends by CNX, planned investments by CNX, and such other factors as the Board of Directors deems relevant. The Company's Credit Facility limits CNX's ability to pay dividends in excess of an annual rate of $0.10 per share when the Company's leverage ratio exceeds 3.50 to 1.00 and subject to an aggregate amount up to a cumulative credit calculation set forth in the Credit Facility. The total leverage ratio was 2.26 to 1.00 at December 31, 2018. The credit facility does not permit dividend payments in the event of default. The indentures to the 5.75% notes due in August 2022 notes limit dividends to $0.50 per share annually unless several conditions are met. These conditions include no defaults, ability to incur additional debt and other payment limitations under the indentures. There were no defaults in the year ended December 31, 2018.

On January 16, 2019, the Board of Directors of CNX Midstream GP LLC, the general partner of CNX Midstream Partners LP, announced the declaration of a cash distribution of $0.3603 per unit with respect to the fourth quarter of 2018. The distribution will be made on February 13, 2019 to unitholders of record as of the close of business on February 5, 2019. The distribution, which equates to an annual rate of $1.4412 per unit, represents an increase of 3.6% over the prior quarter, and an increase of 15% over the distribution paid with respect to the fourth quarter of 2017.

Off-Balance Sheet Transactions

CNX does not maintain off-balance sheet transactions, arrangements, obligations or other relationships with unconsolidated entities or others that are reasonably likely to have a material current or future effect on the Company’s financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources which are not disclosed in the Notes to the Audited Consolidated Financial Statements. CNX uses a combination of surety bonds, corporate guarantees and letters of credit to secure the Company's financial obligations for employee-related, environmental, performance and various other items which are not reflected on the Consolidated Balance Sheet at December 31, 2018. Management believes these items will expire without being funded. See Note 22 - Commitments and Contingent Liabilities in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional details of the various financial guarantees that have been issued by CNX.

Recent Accounting Pronouncements

In October 2018, the Financial Accounting Standards Board (FASB) issued Update 2018-17 - Consolidation - Targeted Improvements to Related Party Guidance for Variable Interest Entities ("VIE") (Topic 810). This Update states that indirect interests held through related parties in common control arrangements should be considered on a proportional basis for determining whether fees paid to decision makers and service providers are variable interests. This is consistent with how indirect interests held through related parties under common control are considered for determining whether a reporting entity must consolidate a VIE. Entities are required to apply the amendments retrospectively. The amendments in this Update are effective for fiscal years beginning after December 15, 2019, and early adoption is permitted. The adoption of this guidance is not expected to have a material impact on the Company's financial statements.

In August 2018, the FASB issued Update 2018-14 - Compensation - Retirement Benefits - Defined Benefit Plans - General (Subtopic 715-20), which modifies the disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans. This Update removes the requirement to disclose the amounts in accumulated other comprehensive income expected to be recognized as components of net periodic benefit cost over the next fiscal year and adds a requirement to disclose an explanation of the reasons for significant gains and losses related to changes in the benefit obligation for the period. For public business entities, the amendments in this Update are effective for fiscal years ending after December 15, 2020, and early adoption is permitted. Entities should apply these amendments retrospectively. The adoption of this guidance is not expected to have a material impact on the Company's financial statements.

In August 2018, the FASB issued Update 2018-13 - Fair Value Measurement (Topic 820), which modifies the disclosure requirements in Topic 820. This Update removes the following disclosure requirements: the amount of and reasons for transfers between Level 1 and Level 2 of the fair value hierarchy, the policy for timing of transfers between levels, and the valuation processes for Level 3 fair value measurements. The Update also makes the following additions: the changes in unrealized gains and losses for the period included in other comprehensive income for recurring Level 3 fair value measurements held at the end of the reporting period and the range and weighted average of significant unobservable inputs used to develop Level 3 fair value measurements. This Update is effective for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years, and early adoption is permitted. Entities should apply the additions prospectively and all other amendments should be applied retrospectively. The adoption of this guidance is not expected to have a material impact on the Company's financial statements.

In February 2018, the FASB issued Update 2018-02 - Income Statement - Reporting Comprehensive Income (Topic 220), which allows a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the Act. Consequently, the amendments eliminate the stranded tax effects resulting from the Act and will improve the usefulness of information reported to financial statement users. However, because the amendments only relate to the reclassification of the income tax effects of the Act, the underlying guidance that requires that the effect of a change in tax laws or rates be included in income from continuing operations is not affected. This Update also requires certain disclosures about stranded tax effects. The amendments in this Update are effective for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. Early adoption is permitted, and the amendments should be applied either in the period of adoption or retrospectively to each period (or periods) in which the effect of the change in the U.S. federal corporate income tax rate in the Act is recognized. The Company early adopted ASU 2018-02 which resulted in the reclassification of $1.1 million, related to stranded tax effects, from accumulated other comprehensive income to retained earnings in the fourth quarter of 2018.

In January 2017, the FASB issued Update 2017-04 - Simplifying the Test of Goodwill Impairment. This Update simplifies the quantitative goodwill impairment test requirements by eliminating the requirement to calculate the implied fair value of goodwill (Step 2 of the current goodwill impairment test). Instead a company would record an impairment charge based on the excess of a reporting unit's carrying value over its fair value (measured in Step 1 of the current goodwill impairment test). This Update is effective for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years, and early adoption is permitted. Entities will apply the standard's provisions prospectively. The Company adopted Update 2017-04 on January 1, 2018 and determined that this standard will not have a material quantitative effect on the financial statements, unless an impairment charge is necessary.

In February 2016, the FASB issued Update 2016-02 - Leases (Topic 842), which increases transparency and comparability among organizations by recognizing right-of-use (ROU) lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. Update 2016-02 maintains a distinction between finance leases and operating leases, which is substantially similar to the classification criteria for distinguishing between capital leases and operating leases in the previous lease guidance. Retaining this distinction allows the recognition, measurement and presentation of expenses and cash flows arising from a lease to remain similar to the previous accounting treatment. A lessee is permitted to make an accounting policy election by class of underlying asset to exclude from balance sheet recognition any lease assets and lease liabilities with a term of 12 months or less, and instead to recognize lease expense on a straight-line basis over the lease term. For both financing and operating leases, the ROU asset and lease liability will be initially measured at the present value of the lease payments in the statement of financial position. For public business entities, the amendments in this update are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. In transition, lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach with the option to adopt certain practical expedients. In July 2018, the FASB issued Update 2018-11 which provides entities with the option to initially apply the new lease standard at the adoption date and recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption.

CNX has substantially completed an analysis of our leases and continues to assess the impact of Topic 842 on our internal controls over financial reporting. The Company will adopt Topic 842 guidance as of January 1, 2019 using the transition method that allows a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. We have elected the transition relief package of practical expedients by applying previous accounting conclusions under ASC 840 to all of our leases that existed prior to the transition date. As a result, CNX will not reassess 1) whether existing or expired contracts contain leases 2) lease classification for any existing or expired leases and 3) whether lease origination costs qualified as initial direct costs. CNX will not elect the practical expedient to use hindsight in determining a lease term and impairment of ROU assets at the adoption date. Additionally, the Company will elect the short-term practical expedient for all of our asset classes by establishing an accounting policy to exclude leases with a term of 12 months or less. CNX will not separate lease components from non-lease components for our specified asset classes. Lastly, CNX will adopt the easement practical expedient which allows the Company to apply ASC 842 prospectively to land easements after the adoption date. Easements that existed or expired prior to the adoption date that were not previously assessed under ASC 840 will not be reassessed. CNX has implemented a third-party supported lease accounting system to account for the identified leases and is currently in the process of performing final testing of this system.

The adoption of Topic 842 will have a material impact on the Company’s Consolidated Balance Sheet due to the initial recognition of ROU assets and lease liabilities. Upon adoption of Topic 842, the Company expects to recognize a ROU asset and corresponding lease liability between $200 million to $225 million on its Consolidated Balance Sheet.

ITEM 7A. **QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK**

In addition to the risks inherent in operations, CNX is exposed to certain financial, market, political and economic risks. The following discussion provides additional detail regarding CNX's exposure to the risks of changing commodity prices, interest rates and foreign exchange rates.

CNX is exposed to market price risk in the normal course of selling natural gas. CNX uses fixed-price contracts, options and derivative commodity instruments to minimize exposure to market price volatility in the sale of natural gas and NGLs. Under our risk management policy, it is not our intent to engage in derivative activities for speculative purposes.

CNX has established risk management policies and procedures to strengthen the internal control environment of the marketing of commodities produced from its asset base. All of the derivative instruments without other risk assessment procedures are held for purposes other than trading. They are used primarily to mitigate uncertainty and volatility, and cover underlying exposures. The Company's market risk strategy incorporates fundamental risk management tools to assess market price risk and establish a framework in which management can maintain a portfolio of transactions within pre-defined risk parameters.

CNX believes that the use of derivative instruments, along with our risk assessment procedures and internal controls, mitigates our exposure to material risks. The use of derivative instruments without other risk assessment procedures could materially affect the Company's results of operations depending on market prices; however, we believe that use of these instruments will not have a material adverse effect on our financial position or liquidity due to our risk assessment procedures and internal controls.

For a summary of accounting policies related to derivative instruments, see Note 1—Significant Accounting Policies in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K.

At December 31, 2018 and December 31, 2017, our open derivative instruments were in a net asset position with a fair value of $99 million and $60 million, respectively. A sensitivity analysis has been performed to determine the incremental effect on future earnings related to open derivative instruments at December 31, 2018 and December 31, 2017. A hypothetical 10 percent increase in future natural gas prices would have decreased the fair value by $427 million and $323 million at December 31, 2018 and December 31, 2017, respectively. A hypothetical 10 percent decrease in future natural gas prices would have increased the fair value by $453 million and $321 million at December 31, 2018 and December 31, 2017, respectively.

CNX's interest expense is sensitive to changes in the general level of interest rates in the United States. At December 31, 2018 and December 31, 2017, CNX had $1,703 million and $2,214 million, respectively, aggregate principal amount of debt outstanding under fixed-rate instruments, including unamortized debt issuance costs of $9 million and $18 million, respectively. At December 31, 2018, CNX had $696 million of debt outstanding under variable-rate instruments, and had no debt outstanding under variable-rate instruments at December 31, 2017. CNX’s primary exposure to market risk for changes in interest rates relates to our revolving credit facility, under which there were $612 million of borrowings at December 31, 2018 and no borrowings at December 31, 2017, and CNXM's revolving credit facility, under which there were $84 million of borrowings at December 31, 2018. A hypothetical 100 basis-point increase in the average rate for CNX's and CNXM's revolving credit facilities would decrease pre-tax future earnings by $7 million at December 31, 2018. There would be no impact on pre-tax future earnings at December 31, 2017.

All of CNX's transactions are denominated in U.S. dollars, and, as a result, it does not have material exposure to currency exchange-rate risks.

Natural Gas Hedging Volumes

As of January 18, 2019, the Company's hedged volumes for the periods indicated are as follows:

	For the Three Months Ended				
	March 31,	June 30,	September 30,	December 31,	Total Year
2019 Fixed Price Volumes					
Hedged Bcf	88.7	96.8	97.9	95.7	376.0*
Weighted Average Hedge Price per Mcf	$2.79	$ 2.67	$ 2.67	$ 2.72	$ 2.71
2020 Fixed Price Volumes					
Hedged Bcf	108.1	120.7	122.0	122.0	468.6*
Weighted Average Hedge Price per Mcf	$2.58	$ 2.54	$ 2.54	$ 2.54	$ 2.55
2021 Fixed Price Volumes					
Hedged Bcf	101.2	102.3	103.4	103.4	410.3
Weighted Average Hedge Price per Mcf	$2.44	$ 2.44	$ 2.44	$ 2.44	$ 2.44
2022 Fixed Price Volumes					
Hedged Bcf	68.2	69.0	69.7	69.7	276.6
Weighted Average Hedge Price per Mcf	$2.48	$ 2.48	$ 2.48	$ 2.48	$ 2.48
2023 Fixed Price Volumes					
Hedged Bcf	31.3	31.7	32.0	32.0	127.0
Weighted Average Hedge Price per Mcf	$2.35	$ 2.35	$ 2.35	$ 2.35	$ 2.35

*Quarterly volumes do not add to annual volumes in as much as a discrete condition in individual quarters, where basis hedge volumes exceed NYMEX hedge volumes, does not exist for the year taken as a whole.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of CNX Resources Corporation and Subsidiaries

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of CNX Resources Corporation and Subsidiaries (the Company) as of December 31, 2018 and 2017, and the related consolidated statements of income, comprehensive income, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2018, and the related notes and financial statement schedule listed in the Index at Item 15 (a) (2) (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the consolidated financial position of the Company at December 31, 2018 and 2017, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 7, 2019 expressed an unqualified opinion thereon.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.
/s/ Ernst & Young LLP

We have served as the Company's auditor since 2008.

Pittsburgh, Pennsylvania
February 7, 2019

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CNX RESOURCES CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

(Dollars in thousands, except per share data)	For the Years Ended December 31,		
	2018	2017	2016
Revenue and Other Operating Income:			
Natural Gas, NGLs and Oil Revenue	$1,577,937	$1,125,224	$793,248
(Loss) Gain on Commodity Derivative Instruments	(30,212)	206,930	(141,021)
Purchased Gas Revenue	65,986	53,795	43,256
Midstream Revenue	89,781	—	—
Other Operating Income	26,942	69,182	64,485
Total Revenue and Other Operating Income	1,730,434	1,455,131	759,968
Costs and Expenses:			
Operating Expense			
Lease Operating Expense	95,139	88,932	96,434
Transportation, Gathering and Compression	302,933	382,865	374,350
Production, Ad Valorem, and Other Fees	32,750	29,267	31,049
Depreciation, Depletion and Amortization	493,423	412,036	419,939
Exploration and Production Related Other Costs	12,033	48,074	14,522
Purchased Gas Costs	64,817	52,597	42,717
Impairment of Exploration and Production Properties	—	137,865	—
Impairment of Other Intangible Assets	18,650	—	—
Selling, General and Administrative Costs	134,806	93,211	104,843
Other Operating Expense	72,412	112,369	88,754
Total Operating Expense	1,226,963	1,357,216	1,172,608
Other (Income) Expense			
Other (Income) Expense	(14,571)	3,825	4,783
Gain on Sale of Assets	(157,015)	(188,063)	(14,270)
Gain on Previously Held Equity Interest	(623,663)	—	—
Loss on Debt Extinguishment	54,118	2,129	—
Interest Expense	145,934	161,443	182,195
Total Other (Income) Expense	(595,197)	(20,666)	172,708
Total Costs and Expenses	631,766	1,336,550	1,345,316
Earnings (Loss) from Continuing Operations Before Income Tax	1,098,668	118,581	(585,348)
Income Tax Expense (Benefit)	215,557	(176,458)	(34,403)
Income (Loss) from Continuing Operations	883,111	295,039	(550,945)
Income (Loss) from Discontinued Operations, net	—	85,708	(297,157)
Net Income (Loss)	883,111	380,747	(848,102)
Less: Net Income Attributable to Noncontrolling Interests	86,578	—	—
Net Income (Loss) Attributable to CNX Resources Shareholders	$796,533	$380,747	$(848,102)

The accompanying notes are an integral part of these financial statements.

CNX RESOURCES CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(CONTINUED)

(Dollars in thousands, except per share data)	For the Years Ended December 31, 2018	2017	2016
Earnings (Loss) Per Share			
Basic			
Income (Loss) from Continuing Operations	$3.75	$1.29	$(2.40)
Income (Loss) from Discontinued Operations	—	0.37	(1.30)
Total Basic Earnings (Loss) Per Share	$3.75	$1.66	$(3.70)
Diluted			
Income (Loss) from Continuing Operations	$3.71	$1.28	$(2.40)
Income (Loss) from Discontinued Operations	—	0.37	(1.30)
Total Diluted Earnings (Loss) Per Share	$3.71	$1.65	$(3.70)
Dividends Declared Per Share	$—	$—	$0.01

CNX RESOURCES CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Dollars in thousands)

	For the Years Ended December 31, 2018	2017	2016
Net Income (Loss)	$883,111	$380,747	$(848,102)
Other Comprehensive Income (Loss):			
Actuarially Determined Long-Term Liability Adjustments (Net of tax: ($792), ($7,365), 16,281)	1,672	12,228	(33,226)
Reclassification of Cash Flow Hedges from Other Comprehensive Income to Earnings (Net of tax: $-, $-, $25,011)	—	—	(43,470)
Other Comprehensive Income (Loss)	1,672	12,228	(76,696)
Comprehensive Income (Loss)	$884,783	$392,975	$(924,798)
Less: Comprehensive Income Attributable to Noncontrolling Interests	86,578	—	—
Comprehensive Income (Loss) Attributable to CNX Resources Shareholders	$798,205	$392,975	$(924,798)

The accompanying notes are an integral part of these financial statements.

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CNX RESOURCES CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)

	December 31, 2018	December 31, 2017
ASSETS		
Current Assets:		
Cash and Cash Equivalents	$17,198	$509,167
Accounts and Notes Receivable:		
Trade	252,424	156,817
Other Receivables	11,077	48,908
Supplies Inventories	9,715	10,742
Recoverable Income Taxes	149,481	31,523
Prepaid Expenses	61,791	95,347
Total Current Assets	501,686	852,504
Property, Plant and Equipment (Note 10):		
Property, Plant and Equipment	9,567,428	9,316,495
Less—Accumulated Depreciation, Depletion and Amortization	2,624,984	3,526,742
Total Property, Plant and Equipment—Net	6,942,444	5,789,753
Other Assets:		
Investment in Affiliates	18,663	197,921
Goodwill	796,359	—
Other Intangible Assets	103,200	—
Other	229,818	91,735
Total Other Assets	1,148,040	289,656
TOTAL ASSETS	$8,592,170	$6,931,913

The accompanying notes are an integral part of these financial statements.

CNX RESOURCES CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Dollars in thousands, except per share data)

	December 31, 2018	December 31, 2017
LIABILITIES AND EQUITY		
Current Liabilities:		
Accounts Payable	$229,806	$211,161
Current Portion of Long-Term Debt (Note 14 and Note 15)	6,997	7,111
Other Accrued Liabilities (Note 13)	286,172	223,407
Total Current Liabilities	522,975	441,679
Long-Term Debt:		
Long-Term Debt (Note 14)	2,378,205	2,187,026
Capital Lease Obligations (Note 15)	13,299	20,347
Total Long-Term Debt	2,391,504	2,207,373
Deferred Credits and Other Liabilities:		
Deferred Income Taxes (Note 8)	398,682	44,373
Asset Retirement Obligations (Note 9)	37,479	198,768
Other	159,787	139,821
Total Deferred Credits and Other Liabilities	595,948	382,962
TOTAL LIABILITIES	3,510,427	3,032,014
Stockholders' Equity:		
Common Stock, $0.01 Par Value; 500,000,000 Shares Authorized, 198,663,342 Issued and Outstanding at December 31, 2018; 223,743,322 Issued and Outstanding at December 31, 2017	1,990	2,241
Capital in Excess of Par Value	2,264,063	2,450,323
Preferred Stock, 15,000,000 Shares Authorized, None Issued and Outstanding	—	—
Retained Earnings	2,071,809	1,455,811
Accumulated Other Comprehensive Loss	(7,904)	(8,476)
Total CNX Resources Stockholders' Equity	4,329,958	3,899,899
Noncontrolling Interest	751,785	—
TOTAL STOCKHOLDERS' EQUITY	5,081,743	3,899,899
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$8,592,170	$6,931,913

The accompanying notes are an integral part of these financial statements.

CNX RESOURCES CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(Dollars in thousands, except per share data)

	Common Stock	Capital in Excess of Par Value	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income (Loss)	Total CNX Resources Stockholders' Equity	Non-Controlling Interest	Total Equity
December 31, 2015	$ 2,294	$ 2,435,497	$ 2,579,834	$ (315,598)	$ 4,702,027	$ 153,749	$ 4,855,776
Net (Loss) Income	—	—	(848,102)	—	(848,102)	8,954	(839,148)
Gas Cash Flow Hedge (Net of $25,011 Tax)	—	—	—	(43,470)	(43,470)	—	(43,470)
Actuarially Determined Long-Term Liability Adjustments (Net of $16,281 Tax)	—	—	—	(33,488)	(33,488)	262	(33,226)
Comprehensive (Loss) Income	—	—	(848,102)	(76,958)	(925,060)	9,216	(915,844)
Shares Withheld for Taxes	—	—	(1,649)	—	(1,649)	—	(1,649)
Issuance of Common Stock	4	—	—	—	4	—	4
Tax Cost from Stock-Based Compensation	—	(4,931)	—	—	(4,931)	—	(4,931)
Amortization of Stock-Based Compensation Awards	—	30,298	—	—	30,298	1,185	31,483
Distributions to Noncontrolling Interests	—	—	—	—	—	(21,657)	(21,657)
Dividends ($0.145 per share)	—	—	(2,294)	—	(2,294)	—	(2,294)
December 31, 2016	$ 2,298	$ 2,460,864	$ 1,727,789	$ (392,556)	$ 3,798,395	$ 142,493	$ 3,940,888
Net Income	—	—	380,747	—	380,747	—	380,747
Actuarially Determined Long-Term Liability Adjustments (Net of ($7,365) Tax)	—	—	—	12,228	12,228	—	12,228
Comprehensive Income	—	—	380,747	12,228	392,975	—	392,975
Issuance of Common Stock	7	1,002	—	—	1,009	—	1,009
Retirement of Common Stock (6,410,900 shares)	(64)	(51,223)	(51,922)	—	(103,209)	—	(103,209)
Distribution of CONSOL Energy, Inc.	—	22,697	(594,122)	371,852	(199,573)	(142,493)	(342,066)
Shares Withheld for Taxes	—	—	(6,681)	—	(6,681)	—	(6,681)
Amortization of Stock-Based Compensation Awards	—	16,983	—	—	16,983	—	16,983
December 31, 2017	$ 2,241	$ 2,450,323	$ 1,455,811	$ (8,476)	$ 3,899,899	$ —	$ 3,899,899
Net Income	—	—	796,533	—	796,533	86,578	883,111
Actuarially Determined Long-Term Liability Adjustments (Net of ($792) Tax)	—	—	—	1,672	1,672	—	1,672
Comprehensive Income	—	—	796,533	1,672	798,205	86,578	884,783
Issuance of Common Stock	8	1,705	—	—	1,713	—	1,713
Purchase and Retirement of Common Stock (25,894,324 shares)	(259)	(206,895)	(176,598)	—	(383,752)	—	(383,752)
Shares Withheld for Taxes	—	—	(5,037)	—	(5,037)	(348)	(5,385)
Acquisition of CNX Gathering, LLC	—	—	—	—	—	718,577	718,577
Amortization of Stock-Based Compensation Awards	—	18,930	—	—	18,930	2,411	21,341
Distributions to CNXM Noncontrolling Interest Holders	—	—	—	—	—	(55,433)	(55,433)
ASU 2018-02 Reclassification	—	—	1,100	(1,100)	—	—	—
December 31, 2018	$ 1,990	$ 2,264,063	$ 2,071,809	$ (7,904)	$ 4,329,958	$ 751,785	$ 5,081,743

The accompanying notes are an integral part of these financial statements.

CNX RESOURCES CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

(Dollars in thousands)	**For the Years Ended December 31,**		
Cash Flows from Operating Activities:	**2018**	**2017**	**2016**
Net Income (Loss)	$883,111	$380,747	$(848,102)
Adjustments to Reconcile Net Income (Loss) to Net Cash Provided by Continuing Operating Activities:			
Net (Income) Loss from Discontinued Operations	—	(85,708)	297,157
Depreciation, Depletion and Amortization	493,423	412,036	419,939
Amortization of Deferred Financing Costs	8,361	10,630	9,059
Impairment of Exploration and Production Properties	—	137,865	—
Impairment of Other Intangible Assets	18,650	—	—
Stock-Based Compensation	21,341	16,983	19,316
Gain on Sale of Assets	(157,015)	(188,063)	(14,270)
Gain on Previously Held Equity Interest	(623,663)	—	—
Loss on Debt Extinguishment	54,118	2,129	—
Loss (Gain) on Commodity Derivative Instruments	30,212	(206,930)	141,021
Net Cash (Paid) Received in Settlement of Commodity Derivative Instruments	(69,720)	(41,174)	245,212
Deferred Income Taxes	345,560	(142,829)	75,892
Return on Equity Investment	—	—	22,268
Equity in Earnings of Affiliates	(5,363)	(49,830)	(53,078)
Changes in Operating Assets:			
Accounts and Notes Receivable	(57,734)	(32,792)	(46,434)
Supplies Inventories	1,027	4,254	(1,486)
Recoverable Income Tax	(118,498)	76,196	(91,313)
Prepaid Expenses	(1,391)	631	76,668
Changes in Other Assets	4,904	22,018	(2,473)
Changes in Operating Liabilities:			
Accounts Payable	12,760	45,669	(17,227)
Accrued Interest	(5,839)	(2,955)	(1,144)
Other Operating Liabilities	53,135	81,969	(41,913)
Changes in Other Liabilities	(1,556)	(7,778)	78,140
Net Cash Provided by Continuing Operating Activities	885,823	433,068	267,232
Net Cash Provided by Discontinued Operating Activities	—	215,619	197,026
Net Cash Provided by Operating Activities	885,823	648,687	464,258
Cash Flows from Investing Activities:			
Capital Expenditures	(1,116,397)	(632,846)	(172,739)
CNX Gathering LLC Acquisition, Net of Cash Acquired	(299,272)	—	—
Proceeds from Noble Exchange Settlement	—	—	213,295
Proceeds from Asset Sales	511,767	414,185	46,989
Net Distributions from Equity Affiliates	9,250	42,873	73,743
Net Cash (Used in) Provided by Continuing Investing Activities	(894,652)	(175,788)	161,288
Net Cash (Used in) Provided by Discontinued Investing Activities	—	(46,133)	326,083
Net Cash (Used in) Provided by Investing Activities	(894,652)	(221,921)	487,371
Cash Flows from Financing Activities:			
Proceeds from (Payments on) CNX Revolving Credit Facility	612,000	—	(952,000)
Payments on Miscellaneous Borrowings	(7,165)	(8,037)	(7,802)
Payments on Long-Term Notes	(955,019)	(239,716)	—
Proceeds from Issuance of CNXM Senior Notes	394,000	—	—

Net Payments on CNXM Revolving Credit Facility	(65,500)	—	—
Distributions to CNXM Noncontrolling Interest Holders	(55,433)	—	—
Proceeds from Spin-Off of CONSOL Energy Inc.	—	425,000	—
Dividends Paid	—	—	(2,294)
Proceeds from Issuance of Common Stock	1,713	1,009	4
Shares Withheld for Taxes	(5,385)	(6,681)	(1,649)
Purchases of Common Stock	(381,752)	(103,209)	—
Debt Issuance and Financing Fees	(20,599)	(361)	—
Net Cash (Used in) Provided by Continuing Financing Activities	(483,140)	68,005	(963,741)
Net Cash Used in Discontinued Financing Activities	—	(31,903)	(6,663)
Net Cash (Used in) Provided by Financing Activities	(483,140)	36,102	(970,404)
Net (Decrease) Increase in Cash and Cash Equivalents	(491,969)	462,868	(18,775)
Cash and Cash Equivalents at Beginning of Period	509,167	46,299	65,074
Cash and Cash Equivalents at End of Period	$ 17,198	$ 509,167	$ 46,299

The accompanying notes are an integral part of these financial statements.

CNX RESOURCES CORPORATION AND SUBSIDIARIES
NOTES TO AUDITED CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in thousands, except per share data)

NOTE 1—SIGNIFICANT ACCOUNTING POLICIES:

A summary of the significant accounting policies of CNX Resources Corporation and subsidiaries ("CNX " or "the Company") is presented below. These, together with the other notes that follow, are an integral part of the Consolidated Financial Statements.

Basis of Consolidation:

The Consolidated Financial Statements include the accounts of CNX Resources Corporation, and its wholly-owned and majority-owned and/or controlled subsidiaries, including certain variable interest entities that the Company is required to consolidate pursuant to the Consolidation topic of the Financial Accounting Standards Board (FASB) Accounting Standards Codification. The portion of these entities that is not owned by the Company is presented as non-controlling interest. Investments in business entities in which CNX does not have control, but has the ability to exercise significant influence over the operating and financial policies, are accounted for under the equity method. All significant intercompany transactions and accounts have been eliminated in consolidation. Investments in oil and natural gas producing entities are accounted for under the proportionate consolidation method.

Discontinued Operations:

Businesses divested are classified in the Consolidated Financial Statements as either discontinued operations or held for sale when the provision of Accounting Standards Codification (ASC) Topic 205 or ASC Topic 360 are met. For businesses classified as discontinued operations, the balance sheet amounts and results of operations are reclassified from their historical presentation to assets and liabilities of discontinued operations on the Consolidated Balance Sheets and to discontinued operations on the Consolidated Statements of Income and Cash Flows for all periods presented. The gains or losses associated with these divested businesses are recorded in discontinued operations on the Consolidated Statements of Income. The disclosures outside of Note 5- Discontinued Operations, for all periods presented, in the accompanying notes generally do not include the assets, liabilities, or operating results of businesses classified as discontinued operations.

Use of Estimates:

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as various disclosures. Actual results could differ from those estimates. The most significant estimates included in, but not limited to, the preparation of the consolidated financial statements are related to salary retirement benefits, fair value of derivative instruments, long-lived assets (including intangibles assets and goodwill), stock-based compensation, asset retirement obligations, deferred income tax assets and liabilities, contingencies and the values of natural gas, NGLs, condensate and oil (collectively "natural gas") reserves.

Cash and Cash Equivalents:

Cash and cash equivalents include cash on hand and on deposit at banking institutions as well as all highly liquid short-term securities with original maturities of three months or less.

Trade Accounts Receivable:

Trade accounts receivable are recorded at the invoiced amount and do not bear interest. CNX reserves for specific accounts receivable when it is probable that all or a part of an outstanding balance will not be collected, such as customer bankruptcies. Collectability is determined based on terms of sale, credit status of customers and various other circumstances. CNX regularly reviews collectability and establishes or adjusts the allowance as necessary using the specific identification method. Account balances are charged off against the allowance after all means of collection have been exhausted and the potential for recovery is considered remote. Reserves for uncollectable amounts were not material in the periods presented. In addition, there were no material financing receivables with a contractual maturity greater than one year at December 31, 2018 or 2017.

Inventories:
Inventories are stated at the lower of cost or net realizable value. The cost of supplies inventory is determined by the average cost method and includes operating and maintenance supplies to be used in the Company's operations.
Property, Plant and Equipment:
CNX uses the successful efforts method of accounting for natural gas producing activities. Costs of property acquisitions, successful exploratory, development wells and related support equipment and facilities are capitalized. Periodic valuation provisions for impairment of capitalized costs of unproved mineral interests are expensed. Costs of unsuccessful exploratory wells are expensed when such wells are determined to be non-productive, or if the determination cannot be made after finding sufficient quantities of reserves to continue evaluating the viability of the project. The costs of producing properties and mineral interests are amortized using the units-of-production method. Wells and related equipment and intangible drilling costs are also amortized on a units-of-production method. Units-of-production amortization rates are revised at least once per year, or more frequently if events and circumstances indicate an adjustment is necessary. Such revisions are accounted for prospectively as changes in accounting estimates.

Property, plant and equipment is recorded at cost upon acquisition. Expenditures which extend the useful lives of existing plant and equipment are capitalized. Interest costs applicable to major asset additions are capitalized during the construction period. Planned major maintenance costs which do not extend the useful lives of existing plant and equipment are expensed as incurred.

Gas advance royalties are royalties that are paid in advance for the right to use an owner's land for the exploration and production of oil, NGLs and natural gas. These advance royalties are evaluated periodically, or at a minimum once per year, for impairment issues or whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Any revisions are accounted for prospectively as changes in accounting estimates.

Depreciation of plant and equipment is calculated on the straight-line method over their estimated useful lives or lease terms, generally as follows:

	Years
Buildings and improvements	10 to 45
Machinery and equipment	3 to 25
Gathering and transmission	30 to 40
Leasehold improvements	Life of Lease

Costs for purchased software are capitalized and amortized using the straight-line method over the estimated useful life which does not exceed seven years.

Impairment of Long-lived Assets:

Impairment of long-lived assets is recorded when indicators of impairment are present and the undiscounted cash flows estimated to be generated by those assets are less than the assets' carrying value. The carrying value of the assets is then reduced to its estimated fair value which is usually measured based on an estimate of future discounted cash flows. Impairment of equity investments is recorded when indicators of impairment are present, and the estimated fair value of the investment is less than the assets' carrying value.

In February 2017, the Company approved a plan to sell its subsidiaries Knox Energy LLC and Coalfield Pipeline Company (collectively, “Knox”). Knox met all of the criteria to be classified as held for sale in February 2017. As part of the required evaluation under the held for sale guidance, during the first quarter, Knox’s book value was evaluated, and it was determined that the approximate fair value less costs to sell Knox was less than the carrying value of the net assets to be sold. The resulting impairment of $137,865 was included in Impairment of Exploration and Production Properties within the Consolidated Statements of Income during the year ended December 31, 2017. The sale of Knox closed in the second quarter of 2017 (See Note 6 - Acquisitions and Dispositions for more information). The disposal of Knox did not represent a strategic shift that would have had a major effect on the Company’s operations and financial results and was, therefore, not classified as a discontinued operation in accordance with Topic 205, Presentation of Financial Statements, and Topic 360, Property, Plant and Equipment.

Impairment of Proved Properties:

CNX performs a quantitative impairment test whenever events or changes in circumstances indicate that an asset group's carrying amount may not be recoverable, over proved properties using the published NYMEX forward prices, timing, methods and other assumptions consistent with historical periods. When indicators of impairment are present, tests require that the Company first compare expected future undiscounted cash flows by asset group to their respective carrying values. If the carrying amount exceeds the estimated undiscounted future cash flows, a reduction of the carrying amount of the natural gas properties to their estimated fair values is required, which is determined based on discounted cash flow techniques using a market-specific weighted average cost of capital. There were no impairments related to proved properties in the years ended December 31, 2018, 2017 or 2016.

Impairment of Unproved Properties:

CNX evaluates capitalized costs of unproved gas properties for recoverability on a prospective basis. Indicators of potential impairment include potential shifts in business strategy, overall economic factors and historical experience. If it is determined that the properties will not yield proved reserves, the related costs are expensed in the period the determination is made. There were no impairments related to unproved properties in the years ended December 31, 2018, 2017 or 2016.

Exploration expense, which is associated primarily with lease expirations, was $12,033, $48,074 and $14,522 for the years ended December 31, 2018, 2017 and 2016, respectively, and is included in Exploration and Production Related Other Costs in the Consolidated Statements of Income.

Impairment of Goodwill:

Goodwill is the cost of an acquisition less the fair value of the identifiable net assets of the acquired business. Goodwill is not amortized, but rather it is evaluated for impairment annually during the fourth quarter, or more frequently if recent events or prevailing conditions indicate it is more likely than not that the fair value of a reporting unit is less than its carrying value. These indicators include, but are not limited to, overall financial performance, industry and market considerations, anticipated future cash flows and discount rates, changes in the stock price with regards to CNX or common unit price with regards to CNXM, regulatory and legal developments, and other relevant factors. In connection with the Midstream Acquisition (See Note 6 - Acquisition and Disposition for more information), CNX recorded $796,359 of goodwill through the application of purchase accounting. The goodwill recorded was allocated to one reporting unit within the Midstream segment.

In connection with the annual evaluation of goodwill for impairment, CNX may first consider qualitative factors to assess whether there are indicators that it is more likely than not that the fair value of a reporting unit may not exceed its carrying amount. To the extent that such indicators exist, a goodwill impairment test is completed. If the carrying value of the goodwill of a reporting unit exceeds its implied fair value, the difference is recognized as an impairment charge. The Company uses a combination of the income approach (generally a discounted cash flow method) and market approach (including the guideline public company method and the guideline transaction method) to estimate the fair value of a reporting unit.

The fair value estimation process requires considerable judgment and determining the fair value is sensitive to changes in assumptions impacting management’s estimates of future financial results. Although CNX believes the estimates and assumptions used in estimating the fair value are reasonable and appropriate, different assumptions and estimates could materially impact the estimated fair value. Future results could differ from our current estimates and assumptions.

CNX performed its annual goodwill impairment test in the fourth quarter of 2018 and determined the estimated fair value exceeded carrying value, and accordingly no adjustment to goodwill was necessary.

Impairment of Definite-Lived Intangible Assets

Definite-lived intangible assets are amortized on a straight-line basis over their estimated economic lives and they are reviewed for impairment when indicators of impairment are present.

In connection with the Midstream Acquisition (See Note 6 - Acquisitions and Dispositions for more information), CNX recorded $128,781 of other intangible assets, which are comprised of customer relationships, through the application of purchase accounting.

In May 2018, CNX determined that the carrying value of a portion of the customer relationship intangible assets that were acquired in connection with the Midstream acquisition exceeded their fair value in conjunction with the Asset Exchange Agreement with HG Energy II Appalachia, LLC (See Note 6 - Acquisitions and Dispositions for more information). CNX recognized an impairment on this intangible asset of $18,650, which is included in Impairment of Other Intangible Assets in the Consolidated Statements of Income.

The customer relationships intangible asset will be amortized on a straight-line basis over approximately 17 years.

Income Taxes:

Deferred tax assets and liabilities are recognized for the expected future tax consequences of events that have been recognized in the Company's financial statements or tax returns. The provision for income taxes represents income taxes paid or payable for the current year and the change in deferred taxes, excluding the effects of acquisitions during the year. Deferred taxes result from differences between the financial and tax bases of the Company's assets and liabilities and are adjusted for changes in tax rates and tax laws when changes are enacted. Valuation allowances are recorded to reduce deferred tax assets when it is more likely than not that a deferred tax benefit will not be realized. CNX evaluates all tax positions taken on the state and federal tax filings to determine if the position is more likely than not to be sustained upon examination. For positions that do not meet the more likely than not to be sustained criteria, the Company determines, on a cumulative probability basis, the largest amount of benefit that is more likely than not to be realized upon ultimate settlement. A previously recognized tax position is reversed when it is subsequently determined that a tax position no longer meets the more likely than not threshold to be sustained. The evaluation of the sustainability of a tax position and the probable amount that is more likely than not is based on judgment, historical experience and on various other assumptions that the Company believes are reasonable under the circumstances. The results of these estimates, that are not readily apparent from other sources, form the basis for recognizing an uncertain tax position liability. Actual results could differ from those estimates upon subsequent resolution of identified matters.

Asset Retirement Obligations:

CNX accrues for dismantling and removing costs of gas-related facilities and related surface reclamation using the accounting treatment prescribed by the Asset Retirement and Environmental Obligations Topic of the FASB Accounting Standards Codification. This topic requires the fair value of an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. Estimates are regularly reviewed by management and are revised for changes in future estimated costs and regulatory requirements. The present value of the estimated asset retirement costs is capitalized as part of the carrying amount of the long-lived asset. Amortization of the capitalized asset retirement cost is generally determined on a units-of-production basis. Accretion of the asset retirement obligation is recognized over time and generally will escalate over the life of the producing asset, typically as production declines. Accretion is included in Depreciation, Depletion and Amortization in the Consolidated Statements of Income.

Retirement Plan:

CNX had a non-contributory defined benefit retirement plan that was transferred to CONSOL Energy at the date of the spin-off and as such CNX no longer maintains the plan. The benefits for this plan were based primarily on years of service and employees' pay. The plan was accounted for using the guidance outlined in the Compensation - Retirement Benefits Topic of the FASB Accounting Standards Codification.

Investment Plan:

CNX has an investment plan that is available to most employees. Throughout the years ended December 31, 2018, 2017 and 2016, the Company's matching contribution was 6% of eligible compensation contributed by eligible employees. The Company may also make discretionary contributions to the Plan ranging from 1% to 6% of eligible compensation for eligible employees (as defined by the Plan). Discretionary contributions made by the Company were

$2,761 for the year ended December 31, 2016. There were no such discretionary contributions made by CNX for the years ended December 31, 2018 and 2017. Total payments and costs were $3,205, $2,866 and $5,858 for the years ended December 31, 2018, 2017 and 2016, respectively, including the discretionary contribution mentioned above.

Revenue Recognition:

Revenues are recognized when the recognition criteria of ASC 606 are met, which generally occurs at the point in which title passes to the customers. For natural gas, NGL and oil revenue, this occurs at the contractual point of delivery. For midstream revenue this occurs when obligations under the terms of the contract with the shipper are satisfied.

CNX sells natural gas to accommodate the delivery points of its customers. In general, this gas is purchased at market price and re-sold on the same day at market price less a small transaction fee. These matching buy/sell transactions include a legal right of offset of obligations and have been simultaneously entered into with the counterparty. These transactions qualify for netting under the Nonmonetary Transactions Topic of the FASB Accounting Standards Codification and are, therefore, recorded net within the Consolidated Statements of Income in the Purchased Gas Revenue line.

CNX purchases natural gas produced by third-parties at market prices less a fee. The gas purchased from third-parties is then resold to end users or gas marketers at current market prices. These revenues and expenses are recorded gross as Purchased Gas Revenue and Purchase Gas Costs, respectively, in the Consolidated Statements of Income. Purchased gas revenue is recognized when title passes to the customer. Purchased gas costs are recognized when title passes to CNX from the third-party.

Contingencies:

From time to time, CNX, or its subsidiaries, are subject to various lawsuits and claims with respect to such matters as personal injury, wrongful death, damage to property, exposure to hazardous substances, governmental regulations (including environmental remediation), employment and contract disputes, and other claims and actions, arising out of the normal course of business. Liabilities are recorded when it is probable that obligations have been incurred and the amounts can be reasonably estimated. Estimates are developed through consultation with legal counsel involved in the defense of these matters and are based upon the nature of the lawsuit, progress of the case in court, view of legal counsel, prior experience in similar matters and management's intended response. Environmental liabilities are not discounted or reduced by possible recoveries from third-parties. Legal fees associated with defending these various lawsuits and claims are expensed when incurred.

Stock-Based Compensation:

Stock-based compensation expense for all stock-based compensation awards is based on the grant date fair value estimated in accordance with the provisions of the Stock Compensation Topic of the FASB Accounting Standards Codification. CNX recognizes these compensation costs on a straight-line basis over the requisite service period of the award, which is generally the award's vesting term. See Note 17–Stock-Based Compensation for more information.

Accounting for Derivative Instruments:

CNX enters into financial derivative instruments to manage its exposure to commodity price volatility. The derivatives are accounted for as an asset or a liability in the accompanying Consolidated Balance Sheets at their fair value using Level 2 inputs, which is further defined in Note 20 - Fair Value of Financial Instruments. Changes in the fair values of derivatives are recorded in earnings unless special hedge accounting criteria are met.

CNX de-designated all of its cash flow hedges on December 31, 2014 and accounts for all existing and future natural gas and NGL commodity hedges on a mark-to-market basis, and records changes in fair value in current period earnings. In connection with this de-designation, CNX froze the balances recorded in Accumulated Other Comprehensive Income at December 31, 2014 and reclassified balances to earnings as the underlying physical transactions occurred. As of December 31, 2016, all gains that had been previously deferred in other comprehensive income ("OCI") were recognized in earnings.

All of the Company's derivative instruments are subject to master netting arrangements with its counterparties, none of which currently require CNX to post collateral for any of its hedges. However, as stated in the counterparty master agreements, if the Company's obligations with one of its counterparties cease to be secured on the same basis as similar obligations with the other lenders under the credit facility, CNX would be required to post collateral for hedges that are in a liability position in excess of defined thresholds. Each of the Company's counterparty master agreements allows, in the event of default, the ability to elect early termination of outstanding contracts. If early termination is elected, CNX and the applicable counterparty would net settle all open hedge positions.

CNX is exposed to credit risk in the event of non-performance by counterparties, whose creditworthiness is subject to continuing review. Historically, CNX has not experienced any issues of non-performance by derivative counterparties.

Recent Accounting Pronouncements:

In October 2018, the FASB issued Update 2018-17 - Consolidation - Targeted Improvements to Related Party Guidance for Variable Interest Entities (Topic 810). This Update states that indirect interests held through related parties in common control arrangements should be considered on a proportional basis for determining whether fees paid to decision makers and service providers are variable interests. This is consistent with how indirect interests held through related parties under common control

are considered for determining whether a reporting entity must consolidate a VIE. Entities are required to apply the amendments retrospectively. The amendments in this Update are effective for fiscal years beginning after December 15, 2019, and early adoption is permitted. The adoption of this guidance is not expected to have a material impact on the Company's financial statements.
In August 2018, the FASB issued Update 2018-14 - Compensation - Retirement Benefits - Defined Benefit Plans - General (Subtopic 715-20), which modifies the disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans. This Update removes the requirement to disclose the amounts in accumulated other comprehensive income expected to be recognized as components of net periodic benefit cost over the next fiscal year and adds a requirement to disclose an explanation of the reasons for significant gains and losses related to changes in the benefit obligation for the period. For public business entities, the amendments in this Update are effective for fiscal years ending after December 15, 2020, and early adoption is permitted. Entities should apply these amendments retrospectively. The adoption of this guidance is not expected to have a material impact on the Company's financial statements.
In August 2018, the FASB issued Update 2018-13 - Fair Value Measurement (Topic 820), which modifies the disclosure requirements in Topic 820. This Update removes the following disclosure requirements: the amount of and reasons for transfers between Level 1 and Level 2 of the fair value hierarchy, the policy for timing of transfers between levels, and the valuation processes for Level 3 fair value measurements. The Update also makes the following additions: the changes in unrealized gains and losses for the period included in other comprehensive income for recurring Level 3 fair value measurements held at the end of the reporting period and the range and weighted average of significant unobservable inputs used to develop Level 3 fair value measurements. This Update is effective for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years, and early adoption is permitted. Entities should apply the additions prospectively and all other amendments should be applied retrospectively. The adoption of this guidance is not expected to have a material impact on the Company's financial statements.
In February 2018, the FASB issued Update 2018-02 - Income Statement - Reporting Comprehensive Income (Topic 220), which allows a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the Act. Consequently, the amendments eliminate the stranded tax effects resulting from the Act and will improve the usefulness of information reported to financial statement users. However, because the amendments only relate to the reclassification of the income tax effects of the Act, the underlying guidance that requires that the effect of a change in tax laws or rates be included in income from continuing operations is not affected. This Update also requires certain disclosures about stranded tax effects. The amendments in this Update are effective for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. Early adoption is permitted, and the amendments should be applied either in the period of adoption or retrospectively to each period (or periods) in which the effect of the change in the U.S. federal corporate income tax rate in the Act is recognized. The Company early adopted ASU 2018-02 which resulted in the reclassification of $1,100, related to stranded tax effects, from accumulated other comprehensive income to retained earnings in the fourth quarter of 2018.
In January 2017, the FASB issued Update 2017-04 - Simplifying the Test of Goodwill Impairment. This Update simplifies the quantitative goodwill impairment test requirements by eliminating the requirement to calculate the implied fair value of goodwill (Step 2 of the current goodwill impairment test). Instead a company would record an impairment charge based on the excess of a reporting unit's carrying value over its fair value (measured in Step 1 of the current goodwill impairment test). This Update is effective for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years, and early adoption is permitted. Entities will apply the standard's provisions prospectively. The Company adopted Update 2017-04 on January 1, 2018 and determined that this standard will not have a material quantitative effect on the financial statements, unless an impairment charge is necessary.
In February 2016, the FASB issued Update 2016-02 - Leases (Topic 842), which increases transparency and comparability among organizations by recognizing right-of-use (ROU) lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. Update 2016-02 maintains a distinction between finance leases and operating leases, which is substantially similar to the classification criteria for distinguishing between capital leases and operating leases in the previous lease guidance. Retaining this distinction allows the

recognition, measurement and presentation of expenses and cash flows arising from a lease to remain similar to the previous accounting treatment. A lessee is permitted to make an accounting policy election by class of underlying asset to exclude from balance sheet recognition any lease assets and lease liabilities with a term of 12 months or less, and instead to recognize lease expense on a straight-line basis over the lease term. For both financing and operating leases, the ROU asset and lease liability will be initially measured at the present value of the lease payments in the statement of financial position. For public business entities, the amendments in this update are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. In transition, lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach with the option to adopt certain practical expedients. In July 2018, the FASB issued Update 2018-11 which provides entities with the option to initially apply the new lease standard at the adoption date and recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption.

CNX has substantially completed an analysis of our leases and continues to assess the impact of Topic 842 on our internal controls over financial reporting. The Company will adopt Topic 842 guidance as of January 1, 2019 using the transition method that allows a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. We have elected the transition relief package of practical expedients by applying previous accounting conclusions under ASC 840 to all of our leases that existed prior to the transition date. As a result, CNX will not reassess 1) whether existing or expired contracts contain leases 2) lease classification for any existing or expired leases and 3) whether lease origination costs qualified as initial direct costs. CNX will not elect the practical expedient to use hindsight in determining a lease term and impairment of ROU assets at the adoption date. Additionally, the Company will elect the short-term practical expedient for all of our asset classes by establishing an accounting policy to exclude leases with a term of 12 months or less. CNX will not separate lease components from non-lease components for our specified asset classes. Lastly, CNX will adopt the easement practical expedient which allows the Company to apply ASC 842 prospectively to land easements after the adoption date. Easements that existed or expired prior to the adoption date that were not previously assessed under ASC 840 will not be reassessed. CNX has implemented a third-party supported lease accounting system to account for the identified leases and is currently in the process of performing final testing of this system.

The adoption of Topic 842 will have a material impact on the Company’s Consolidated Balance Sheet due to the initial recognition of ROU assets and lease liabilities. Upon adoption of Topic 842, the Company expects to recognize a ROU asset and corresponding lease liability between $200,000 to $225,000 on its Consolidated Balance Sheet.

Reclassifications:

Certain amounts in prior periods have been reclassified to conform with the report classifications of the year ended December 31, 2018, with no effect on previously reported net income, stockholders' equity, or statement of cash flows.

Subsequent Events:

The Company has evaluated all subsequent events through the date the financial statements were issued. No material recognized, or non-recognizable subsequent events were identified other than disclosed in Note 26 - Subsequent Event.

NOTE 2—EARNINGS PER SHARE:

Basic earnings per share is computed by dividing net income attributable to CNX shareholders by the weighted average shares outstanding during the reporting period. Diluted earnings per share is computed similarly to basic earnings per share, except that the weighted average shares outstanding are increased to include additional shares from stock options, performance stock options, restricted stock units and performance share units, if dilutive. The number of additional shares is calculated by assuming that outstanding stock options and performance share options were exercised, that outstanding restricted stock units and performance share units were released, and that the proceeds from such activities were used to acquire shares of common stock at the average market price during the reporting period. CNX Midstream Partners LP's ("CNXM") dilutive units did not have a material impact on the Company's earnings per share calculations for the period from January 3, 2018 through December 31, 2018.

The table below sets forth the share-based awards that have been excluded from the computation of diluted earnings per share because their effect would be antidilutive:

	For the Years Ended December 31,		
	2018	**2017**	**2016**
Anti-Dilutive Options	2,285,775	2,773,423	6,208,813

Anti-Dilutive Restricted Stock Units	—	18,598	663,003
Anti-Dilutive Performance Share Units	145,217	—	2,400,326
Anti-Dilutive Performance Share Options	927,268	927,268	802,804
	3,358,260	3,719,289	10,074,946

The computations for basic and diluted earnings per share are as follows:

	For the Years Ended December 31,		
	2018	2017	2016
Income (Loss) from Continuing Operations	$883,111	$ 295,039	$ (550,945)
Less: Net Income Attributable to Non-Controlling Interest	86,578	—	—
Net Income from Continuing Operations Attributable to CNX Resources Shareholders	$796,533	$ 295,039	$ (550,945)
Income (Loss) from Discontinued Operations	—	85,708	(297,157)
Net Income (Loss) Attributable to CNX Resources Shareholders	$796,533	$ 380,747	$ (848,102)
Weighted-average shares of common stock outstanding	212,348,581	228,835,112	229,387,403
Effect of diluted shares	2,280,384	2,116,700	—
Weighted-average diluted shares of common stock outstanding	214,628,965	230,951,812	229,387,403
Earnings (Loss) Per Share:			
Basic (Continuing Operations)	$3.75	$ 1.29	$ (2.40)
Basic (Discontinued Operations)	—	0.37	(1.30)
Total Basic	$3.75	$ 1.66	$ (3.70)
Diluted (Continuing Operations)	$3.71	$ 1.28	$ (2.40)
Diluted (Discontinued Operations)	—	0.37	(1.30)
Total Diluted	$3.71	$ 1.65	$ (3.70)

Shares of common stock outstanding were as follows:

	For the Years Ended December 31,		
	2018	2017	2016
Balance, Beginning of Year	223,743,322	229,443,008	229,054,236
Issuance Related to Stock-Based Compensation (1)	814,344	711,214	388,772
Retirement of Common Stock (2)	(25,894,324)	(6,410,900)	—
Balance, End of Year	198,663,342	223,743,322	229,443,008

(1) See Note 17 - Stock-Based Compensation for additional information.
(2) See Note 7 - Stock Repurchase for additional information.

NOTE 3—CHANGES IN ACCUMULATED OTHER COMPREHENSIVE LOSS:

Changes in Accumulated Other Comprehensive Loss related to pension obligations, net of tax, were as follows:

	Amount
Balance at December 31, 2017	$ (8,476)
Other Comprehensive Income before Reclassifications	1,736
Amounts Reclassified from Accumulated Other Comprehensive Loss, net of tax	(64)
Current Period Other Comprehensive Income	1,672
ASU 2018-02 Reclassification	(1,100)
Balance at December 31, 2018	$ (7,904)

The following table shows the reclassification of adjustments out of Accumulated Other Comprehensive Loss:

	For the Years Ended December 31,		
	2018	2017	2016
Derivative Instruments (Note 21)			
Natural Gas Price Swaps and Options	$—	$—	$(68,481)
Tax Expense	—	—	25,011
Net of Tax	$—	$—	$(43,470)
Actuarially Determined Long-Term Liability Adjustments* (Note 16)			
Amortization of Prior Service Costs	$(193)	$(2,775)	$(590)
Recognized Net Actuarial Loss	302	23,043	23,857
Settlement Loss	—	—	22,196
Total	109	20,268	45,463
Less: Tax Benefit	173	7,499	16,959
Net of Tax	$(64)	$12,769	$28,504

*Excludes amounts related to the remeasurement of the actuarially determined pension obligations for the years ended December 31, 2018, 2017 and 2016. The table above only shows the reclassifications out of Accumulated Other Comprehensive Loss that relates to continuing operations.

NOTE 4—REVENUE FROM CONTRACTS WITH CUSTOMERS:

On January 1, 2018, the Company adopted Accounting Standards Update (ASU) No. 2014-09, Revenue from Contracts with Customers and all the related amendments ("new revenue standard") using the modified retrospective method, which did not result in any changes to previously reported financial information. The updates related to the new revenue standard were applied only to contracts that were not complete as of January 1, 2018.

Revenue from Contracts with Customers

Revenues are recognized when control of the promised goods or services is transferred to the Company's customers, in an amount that reflects the consideration the Company expects to be entitled to in exchange for those goods or services. The Company has elected to exclude all taxes from the measurement of transaction price.

Nature of Performance Obligations

At contract inception, the Company assesses the goods and services promised in its contracts with customers and identifies a performance obligation for each promised good or service that is distinct. To identify the performance obligations, the Company considers all of the goods or services promised in the contract regardless of whether they are explicitly stated or are implied by customary business practices.

For natural gas, NGLs and oil, and purchased gas revenue, the Company generally considers the delivery of each unit (MMBtu or Bbl) to be a separate performance obligation that is satisfied upon delivery. Payment terms for these contracts typically require payment within 25 days of the end of the calendar month in which the hydrocarbons are delivered. A significant number of these contracts contain variable consideration because the payment terms refer to market prices at future delivery dates. In these situations, the Company has not identified a standalone selling price because the terms of the variable payments relate specifically to the Company's efforts to satisfy the performance obligations. A portion of the contracts contain fixed consideration (i.e. fixed price contracts or contracts with a fixed differential to NYMEX or index prices). The fixed consideration is allocated to each performance obligation on a relative standalone selling price basis, which requires judgment from management. For these contracts, the Company generally concludes that the fixed price or fixed differentials in the contracts are representative of the standalone selling price. Revenue associated with natural gas, NGLs and oil as presented on the accompanying Consolidated Statement of Income represent the Company's share of revenues net of royalties and excluding revenue interests owned by others. When selling natural gas, NGLs and oil on behalf of royalty owners or working interest owners, the Company is acting as an agent and thus reports the revenue on a net basis.

Midstream revenue consists of revenues generated from natural gas gathering activities. The gas gathering services are interruptible in nature and include charges for the volume of gas actually gathered and do not guarantee access to the system. Volumetric based fees are based on actual volumes gathered. The Company generally considers the interruptible gathering of each unit (MMBtu) of natural gas as a separate performance obligation. Payment terms for these contracts typically require payment within 25 days of the end of the calendar month in which the hydrocarbons are gathered.

Transaction price allocated to remaining performance obligations

Accounting Standards Codification (ASC) 606 requires that the Company disclose the aggregate amount of transaction price that is allocated to performance obligations that have not yet been satisfied. However, the guidance provides certain practical expedients that limit this requirement, including when variable consideration is allocated entirely to a wholly unsatisfied performance obligation or to a wholly unsatisfied promise to transfer a distinct good or service that forms part of a series.

A significant portion of our natural gas, NGLs and oil and purchased gas revenue is short-term in nature with a contract term of one year or less. For those contracts, we have utilized the practical expedient in ASC 606-10-50-14 exempting the Company from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

For revenue associated with contract terms greater than one year, a significant portion of the consideration in those contracts is variable in nature and the Company allocates the variable consideration in its contract entirely to each specific performance obligation to which it relates. Therefore, any remaining variable consideration in the transaction price is allocated entirely to wholly unsatisfied performance obligations. As such, the Company has not disclosed the value of unsatisfied performance obligations pursuant to the practical expedient.

For revenue associated with contract terms greater than one year with a fixed price component, the aggregate amount of the transaction price allocated to remaining performance obligations was $167,851 as of December 31, 2018. The Company expects to recognize net revenue of $53,078 in the next 12 months and $38,071 over the following 12 months, with the remainder recognized thereafter.

For revenue associated with our midstream contracts, which also have terms greater than one year, we have utilized the practical expedient in ASC 606-10-50-14 exempting the Company from disclosure of the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under our midstream contracts, the interruptible gathering of each unit of natural gas represents a separate performance obligation; therefore, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligations is not required.

Prior-period performance obligations

We record revenue in the month production is delivered to the purchaser. However, settlement statements for certain natural gas and NGL revenue may not be received for 30 to 90 days after the date production is delivered, and as a result, we are required to estimate the amount of production delivered to the purchaser and the price that will be received for the sale of the product. We record the differences between our estimates and the actual amounts received in the month that payment is received from the purchaser. We have existing internal controls for our revenue estimation process and related accruals, and any identified differences between our revenue estimates and actual revenue received historically have not been significant. For each of the years ended December 31, 2018, 2017, and 2016, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

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Disaggregation of Revenue

The following table is a disaggregation of our revenue by major sources:

	For the Years Ended December 31,		
	2018	2017	2016
Revenue from Contracts with Customers			
Natural Gas Revenue	$1,391,459	$945,382	$670,399
NGLs Revenue	165,883	156,132	97,580
Condensate Revenue	17,559	20,531	22,748
Oil Revenue	3,036	3,179	2,521
Total Natural Gas, NGLs and Oil Revenue	1,577,937	1,125,224	793,248
Purchased Gas Revenue	65,986	53,795	43,256
Midstream Revenue	89,781	—	—
Other Sources of Revenue and Other Operating Income			
(Loss) Gain on Commodity Derivative Instruments	(30,212)	206,930	(141,021)
Other Operating Income	26,942	69,182	64,485
Total Revenue and Other Operating Income	$1,730,434	$1,455,131	$759,968

The disaggregated revenue information corresponds with the Company's segment reporting.

Contract balances

We invoice customers once our performance obligations have been satisfied, at which point payment is unconditional. Accordingly, our contracts with customers do not give rise to contract assets or liabilities under ASC 606. The Company has no contract assets recognized from the costs to obtain or fulfill a contract with a customer.

The opening and closing balances of the Company's receivables related to contracts with customers were $156,817 and $252,424, respectively. Included in the opening balance are receivables of $9,353 related to the January 3, 2018 acquisition by CNX Gas of NBL Midstream's interests (See Note 6 - Acquisitions and Dispositions for more information).

NOTE 5—DISCONTINUED OPERATIONS:

On November 28, 2017, CNX announced that it had completed the tax-free spin-off of its coal business resulting in two independent, publicly traded companies: (i) a coal company, CONSOL Energy, formerly known as CONSOL Mining Corporation and (ii) CNX, a natural gas exploration and production company, formerly known as CONSOL Energy, Inc. Following the separation, CONSOL Energy and its subsidiaries hold the coal assets previously held by CNX, including its Pennsylvania Mining Complex, Baltimore Marine Terminal, its direct and indirect ownership interest in CONSOL Coal Resources LP, formerly known as CNXC Coal Resources LP, and other related coal assets previously held by CNX. As of the close of business on November 28, 2017, CNX's shareholders received one share of CONSOL Energy common stock for every eight shares of CNX common stock held as of November 15, 2017. The coal business has been reclassified to discontinued operations for all periods presented.

In August 2016, CNX completed the sale of the Miller Creek and Fola Mining Complexes. In the transaction, the buyer acquired the Miller Creek and Fola assets and assumed the Miller Creek and Fola mine closing and reclamation liabilities. In order to equalize the value exchange, CNX paid $28,271 of cash at closing, which included property taxes associated with the properties sold and other closing costs. This amount was included in Net Cash (Used in) Provided by Discontinued Investing Activities in the Consolidated Statements of Cash Flows for the year ended December 31, 2016. CNX will also pay a total of $12,291 in remaining installments through January 2020. The net loss on the sale of $53,130, excluding the related impairment charge discussed below, was included in Income (Loss) from Discontinued Operations, net in the Consolidated Statements of Income. Prior to the closing, the Miller Creek and Fola Mining Complexes were classified as held for sale in discontinued operations and in accordance with the accounting guidance for Property, Plant and Equipment, assets held for sale are required to be measured at the lower of carrying value or fair value less costs to sell. Upon meeting the assets held for sale criteria, the Company determined the carrying value of the Miller Creek and Fola Mining Complexes exceeded the fair value less costs to sell. As a result, an impairment charge of $355,681 was recorded during the year ended December 31, 2016. This impairment was included in Income (Loss) from Discontinued Operations, net in the Consolidated Statements of Income.

In March 2016, CNX completed the sale of its membership interests in CONSOL Buchanan Mining Company, LLC ("BMC"), which owned and operated the Buchanan Mine located in Mavisdale, Virginia; various assets relating to the Amonate Mining Complex located in Amonate, Virginia; Russell County, Virginia coal reserves and Pangburn Shaner Fallowfield coal reserves located in Southwestern, Pennsylvania to Coronado IV LLC ("Coronado"). Various CNX assets were excluded from the sale including coalbed methane, natural gas and minerals other than coal, current assets of BMC, certain coal seams and certain surface rights and properties. Coronado assumed only specified liabilities and various CNX liabilities were excluded and not assumed. The excluded liabilities included BMC’s indebtedness, trade payables and liabilities arising prior to closing, as well as the liabilities of the subsidiaries other than BMC which were parties to the sale. In addition, the buyer agreed to pay CNX for Buchanan Mine coal sold outside the U.S. and Canada during the five years following closing a royalty of 20% of any excess of the gross sales price per ton over the following amounts: (1) year one, $75.00 per ton; (2) year two, $78.75 per ton; (3) year three, $82.69 per ton; (4) year four, $86.82 per ton; (5) year five, $91.16 per ton. Total gross royalty income recognized under this agreement was $16,244, $10,073 and $9,575 for the years ended December 31, 2018, 2017 and 2016, respectively. In connection with the separation and distribution agreement with CONSOL Energy (See Note 25 - Related Party) the royalty related to Buchanan Mine was retained by CNX and any related income is included in Other (Income) Expense in the Consolidated Statements of Income. Cash proceeds of $402,799 were received at closing and are included in Net Cash (Used in) Provided by Discontinued Investing Activities on the Consolidated Statements of Cash Flows for the year ended December 31, 2016. The net loss on the sale was $38,364 and was included in Income (Loss) from Discontinued Operations, net in the Consolidated Statements of Income for the year ended December 31, 2016.

For all periods presented in the accompanying Consolidated Statements of Income, BMC along with the various other assets and the Miller Creek and Fola Mining Complexes are classified as discontinued operations.

The following table details selected financial information for the divested business included within discontinued operations:

	For the Years Ended December 31,	
	2017	**2016**
Coal Revenue	$1,067,841	$1,168,486
Other Outside Sales	60,066	31,464
Freight-Outside Coal	66,297	47,790
Miscellaneous Other Income	73,645	74,382
Gain on Sale of Assets	—	269,124
Total Revenue and Other Income	$1,267,849	$1,591,246
Total Costs	1,147,254	1,652,921
Income (Loss) From Operations Before Income Taxes	$120,595	$(61,675)
Impairment on Assets Held for Sale	—	355,681
Income Tax Expense (Benefit)	23,984	(129,153)
Less: Net Income Attributable to Noncontrolling interest	10,903	8,954
Income (Loss) From Discontinued Operations, net	$85,708	$(297,157)

NOTE 6—ACQUISITIONS AND DISPOSITIONS:

On December 14, 2017, CNX Gas entered into a purchase agreement with Noble, pursuant to which CNX Gas acquired Noble’s 50% membership interest in CONE Gathering LLC ("CNX Gathering"), for a cash purchase price of $305,000 and the mutual release of all outstanding claims (the "Midstream Acquisition"). CNX Gathering owns a

100% membership interest in CONE Midstream GP LLC (the "general partner"), which is the general partner of CONE Midstream Partners LP ("CNXM" or the "Partnership"), which is a publicly traded master limited partnership formed in May 2014 by CNX Gas and Noble. In conjunction with the Midstream Acquisition, which closed on January 3, 2018, the general partner, CNXM and CONE Gathering LLC changed their names to CNX Midstream GP LLC, CNX Midstream Partners LP, and CNX Gathering LLC, respectively.

Prior to the Midstream Acquisition, the Company accounted for its 50% interest in CNX Gathering LLC as an equity method investment as the Company had the ability to exercise significant influence, but not control, over the operating and financial policies of the midstream operations. In conjunction with the Midstream Acquisition, the Company obtained a controlling interest in CNX Gathering LLC and, through CNX Gathering's ownership of the general partner, control over CNXM. Accordingly, the Midstream Acquisition has been accounted for as a business combination using the acquisition method of accounting pursuant to

ASC Topic 805, *Business Combinations*, or ASC 805. ASC 805 requires that, in circumstances where a business combination is achieved in stages (or step acquisition), previously held equity interests are remeasured at fair value and any difference between the fair value and the carrying value of the equity interest held be recognized as a gain or loss on the statement of income.

The fair value assigned to the previously held equity interest in CNX Gathering and CNXM for purposes of calculating the gain or loss was $799,033 and was determined using the income approach, based on a discounted cash flow methodology. The resulting gain on remeasurement to fair value of the previously held equity interest in CNX Gathering and CNXM of $623,663 is included in Gain on Previously Held Equity Interest in the Consolidated Statements of Income.

The fair value of the previously held equity interests was based on inputs that are not observable in the market and therefore represent Level 3 inputs (See Note 20 - Fair Value of Financial Instruments). The fair value was measured using valuation techniques that convert future cash flows into a single discounted amount. Significant inputs to the valuation included estimates of: (i) gathering volumes; (ii) future operating costs; and (iii) a market-based weighted average cost of capital. These inputs required significant judgments and estimates by management.

The fair value of midstream facilities and equipment, generally consisting of pipeline systems and compression stations, were estimated using the cost approach. Significant unobservable inputs in the valuation include management's assumptions about the replacement costs for similar assets, the relative age of the acquired assets and any potential economic or functional obsolescence associated with the acquired assets. As a result, the fair value estimates of the midstream facilities and equipment represents a Level 3 fair value measurement.

As part of the purchase price allocation, the Company identified intangible assets for customer relationships with third-party customers. The fair value of the identified intangible assets was determined using the income approach, which requires a forecast of the expected future cash flows generated and an estimated market-based weighted average cost of capital. Significant unobservable inputs in the valuation include future revenue estimates, future cost assumptions, and estimated customer retention rates. As a result, the fair value estimate of the identified intangible assets represents a Level 3 fair value measurement.

The noncontrolling interest in the acquired business is comprised of the limited partner units in CNXM, which were not acquired by the Company. The CNXM limited partner units are actively traded on the New York Stock Exchange and were valued based on observable market prices as of the transaction date and therefore represent a Level 1 fair value measurement.

Allocation of Purchase Price (Midstream Acquisition)

The following table summarizes the purchase price and the amounts of identified assets acquired and liabilities assumed based on the fair value as of January 3, 2018, with any excess of the purchase price over the fair value of the identified net assets acquired recorded as goodwill. The purchase price allocation has been finalized as of December 31, 2018.

Fair Value of Consideration Transferred:	
Cash Consideration	$305,000
CNX Gathering Cash on Hand at January 3, 2018 Distributed to Noble	2,620
Fair Value of Previously Held Equity Interest	799,033
Total Fair Value of Consideration Transferred	$1,106,653

The following is a summary of the fair values of the net assets acquired:

Fair Value of Assets Acquired:	
Cash and Cash Equivalents	$8,348
Accounts and Notes Receivable	21,199
Prepaid Expense	2,006
Other Current Assets	163
Property, Plant and Equipment, Net	1,043,340
Intangible Assets	128,781
Other	593
Total Assets Acquired	1,204,430
Fair Value of Liabilities Assumed:	
Accounts Payable	26,059
CNXM Revolving Credit Facility	149,500
Total Liabilities Assumed	175,559
Total Identifiable Net Assets	1,028,871
Fair Value of Noncontrolling Interest in CNXM	(718,577)
Goodwill	796,359
Net Assets Acquired	$1,106,653

(Midstream Acquisition)

	December 31, 2018
Midstream Revenue	$ 258,074
Earnings from Continuing Operations Before Income Tax	$ 133,811

(Midstream Acquisition)

The following unaudited pro forma combined financial information presents the Company’s results as though the Midstream Acquisition had been completed at January 1, 2016. The pro forma combined financial information has been included for comparative purposes and is not necessarily indicative of the results that might have actually occurred had the acquisition been completed at January 1, 2016; furthermore, the financial information is not intended to be a projection of future results.

	For the Year Ended December 31,	
(in thousands, except per share data) (unaudited)	**2017**	**2016**
Pro Forma Total Revenue and Other Operating Income	$1,553,078	876,987
Pro Forma Net Income from Continuing Operations	$427,381	$(422,284)
Less: Pro Forma Net income Attributable to Noncontrolling Interests	$74,251	$62,301
Pro Forma Net Income(Loss) from Continuing Operations Attributable to CNX	$353,130	$(484,585)
Pro Forma Income(Loss) per Share from Continuing Operations (Basic)	$1.33	$(2.11)
Pro Forma Income(Loss) per Share from Continuing Operations (Diluted)	$1.33	$(2.11)

On August 31, 2018, CNX closed on the sale of substantially all of its Ohio Utica Joint Venture Assets in the wet gas Utica Shale areas of Belmont, Guernsey, Harrison, and Noble Counties, which included approximately 26,000 net undeveloped acres. The net cash proceeds of $381,124 are included in Proceeds from Asset Sales on the Consolidated Statements of Cash Flows and the net gain on the transaction of $130,710 is included in Gain on Asset Sales in the Consolidated Statements of Income.

On May 2, 2018, CNX closed on an Asset Exchange Agreement (the "AEA"), with HG Energy II Appalachia, LLC ("HG Energy"), pursuant to which, among other things, (i) HG Energy paid approximately $7,000 to CNX and assigned to CNX certain undeveloped Marcellus and Utica acreage in Southwest Pennsylvania, and (ii) CNX assigned its interest in certain non-core midstream assets and surface acreage to HG Energy and released certain HG Energy oil and gas acreage from dedication under a gathering agreement that is partially held, indirectly, by CNX. In connection with the transaction, CNX also agreed to certain transactions with CNXM, including the amendment of the existing gas gathering agreement between CNX and CNXM to increase the existing well commitment by an additional forty wells. The net gain on the sale was $286 and is included in Gain on Asset Sales in the Consolidated Statements of Income.

As a result of the AEA, CNX determined that the carrying value of a portion of the customer relationship intangible assets that were acquired in connection with the Midstream Acquisition (see also Note 11 - Goodwill and Other Intangible Assets) exceeded their fair value, and recognized an impairment of approximately $18,650, which is included in Impairment of Other Intangible Assets in the Consolidated Statements of Income.
On March 30, 2018, CNX Gas completed the sale of substantially all of its shallow oil and gas assets and certain Coalbed Methane (CBM) assets in Pennsylvania and West Virginia for $89,921 in cash consideration. In connection with the sale, the buyer assumed approximately $196,514 of asset retirement obligations. The net gain on the sale was $4,227 and is included in Gain on Asset Sales in the Consolidated Statements of Income.

In September 2017, CNX closed on the sale of approximately 22,000 acres of surface land in Colorado. CNX received net cash proceeds of $23,703 which is included in cash flows from investing activities. The net gain on the sale was $18,758 and was included in Gain on Sale of Assets in the Consolidated Statements of Income.

In a two-part closing in July and September 2017, CNX executed the sale of approximately 7,500 net undeveloped acres of the Marcellus Shale in Allegheny and Westmoreland counties, Pennsylvania. CNX received total cash proceeds of $36,649 which is included in cash flows from investing activities. The net gain on the sale of these assets was $15,251 and was included in Gain on Sale of Assets in the Consolidated Statements of Income.

In June 2017, CNX closed on the sale of approximately 11,100 net undeveloped acres of the Marcellus and Utica Shale in Allegheny, Washington, and Westmoreland counties, Pennsylvania. CNX received total cash proceeds of $83,500 which is included in cash flows from investing activities. The net gain on the sale of these assets was $58,541 and was included in Gain on Sale of Assets in the Consolidated Statements of Income.

In June 2017, the Company finalized the sale of 12 producing wells, 15 drilled but uncompleted wells (DUCs), and approximately 11,000 net developed and undeveloped Marcellus and Utica acres in Doddridge and Wetzel counties in West Virginia that were previously classified as held for sale. CNX received total cash proceeds of $125,507 which is included in cash flows from investing activities, as well as undeveloped acreage. The net loss on the sale was $9,430 and was included in Gain on Sale of Assets in the Consolidated Statements of Income.

In May 2017, CNX finalized the sale of approximately 6,300 net undeveloped acres of the Utica-Point Pleasant Shale in Jefferson, Belmont and Guernsey counties, Ohio that were previously classified as held for sale. CNX received total cash proceeds of $76,585 which is included in cash flows from investing activities. The net gain on the sale of these assets was $72,346 and was included in Gain on Sale of Assets in the Consolidated Statements of Income.

In April 2017, CNX finalized the sale of its Knox Energy LLC and Coalfield Pipeline Company subsidiaries that were previously classified as held for sale. At closing, CNX received net cash proceeds of $19,055 which is included in cash flows from investing activities. The net gain on the sale of these assets was $606 and was included in the Gain on Sale of Assets in the Consolidated Statements of Income. In February 2017, Knox met all of the criteria to be classified as held for sale. As part of the required evaluation under the held for sale guidance, during the first quarter, Knox's book value was evaluated, and it was determined that the approximate fair value less costs to sell Knox was less than the carrying value of the net assets to be sold. The resulting impairment of $137,865 was included in Impairment of Exploration and Production Properties in the Consolidated Statements of Income during the year ended December 31, 2017.

NOTE 7— STOCK REPURCHASE:

In September 2017, CNX's Board of Directors approved a one-year stock repurchase program of up to $200,000. On October 30, 2017, the Board approved an increase to the aggregate amount of the repurchase plan to $450,000. On July 30, 2018, the Board approved the extension of the stock repurchase program through December 31, 2018. On October 26, 2018, the Company's Board of Directors approved an additional $300,000 share repurchase authorization, which is not subject to an expiration date. The repurchases may be affected from time-to-time through open market purchases, privately negotiated transactions, Rule 10b5-1 plans, accelerated stock repurchases, block trades, derivative contracts or otherwise in compliance with Rule 10b-18. The timing of any repurchases will be based on a number of factors, including available liquidity, the Company's stock price, the Company's financial outlook, and alternative investment options. The stock repurchase program does not obligate the Company to repurchase any dollar amount or number of shares and the Board may modify, suspend, or discontinue its authorization of the program at any time. The Board of Directors will continue to evaluate the size of the stock repurchase program based on CNX's free cash flow position, leverage ratio, and capital plans. During the year ended December 31, 2018, 25,894,324 shares were repurchased and retired at an average price of $14.80 per share for a total cost of $383,752.

NOTE 8—INCOME TAXES:

Income tax expense (benefit) provided on earnings from continuing operations consisted of:

	For the Years Ended December 31,		
	2018	**2017**	**2016**
Current:			
U.S. Federal	$(130,003)	$(31,791)	$(101,596)
U.S. State	—	(1,838)	(8,699)
	(130,003)	(33,629)	(110,295)
Deferred:			
U.S. Federal	319,813	(166,112)	80,207
U.S. State	25,747	23,283	(4,315)
	345,560	(142,829)	75,892
Total Income Tax Expense (Benefit)	$215,557	$(176,458)	$(34,403)

The components of the net deferred taxes are as follows:

	December 31, 2018	December 31, 2017
Deferred Tax Assets:		
Alternative Minimum Tax	$102,482	$188,080
Net Operating Loss - Federal	124,341	99,524
Net Operating Loss - State	110,339	107,756
Foreign Tax Credit	43,194	44,402
Interest Limitation	32,147	—
Equity Compensation	13,096	21,866
Gas Well Closing	10,140	55,486
Salary Retirement	9,434	9,404
Capital Lease	1,624	2,020
Other	13,714	11,831
Total Deferred Tax Assets	460,511	540,369
Valuation Allowance	(94,455)	(136,576)
Net Deferred Tax Assets	366,056	403,793
Deferred Tax Liabilities:		
Property, Plant and Equipment	(606,342)	(424,204)
Investment in Partnership	(125,253)	(1,251)
Gas Derivatives	(26,160)	(15,248)
Advance Gas Royalties	(3,384)	(3,648)
Other	(3,599)	(3,815)
Total Deferred Tax Liabilities	(764,738)	(448,166)
Net Deferred Tax Liability	$(398,682)	$(44,373)

Deferred taxes are recorded for certain tax benefits, including net operating losses and tax credit carry-forwards, if management assesses the utilization of those assets to be more likely than not. A valuation allowance is required when it is not more likely than not that all or a portion of a deferred tax asset will be realized. All available evidence, both positive and negative, must be considered in determining the need for a valuation allowance. For the years ended December 31, 2018 and 2017, positive evidence considered included financial earnings generated over the past three years for certain subsidiaries, reversals of financial to tax temporary differences and the implementation of and/or ability to employ various tax planning strategies. Negative evidence includes financial and tax losses generated in prior periods and the inability to achieve forecasted results for those periods.

As of December 31, 2018, the Company has a deferred tax asset related to federal net operating losses of $124,341, which expire at various times between 2034 and 2037. However, because of the Tax Cuts and Jobs Act (the “Act”) enacted on December 22, 2017, the anticipated federal net operating loss generated in 2018 does not expire but may only offset 80% of taxable income in any given year. In connection with the restructuring and separation of the Company's coal business in November 2017, certain net operating loss (NOL) carry-forwards were required to be written off. As of December 31, 2017, the Company had written off the deferred tax assets associated with these net operating losses of $24,942 (Gross NOL of $71,263 at 35%). The net limited NOLs after carrybacks of 2016 and 2017 NOLs and return to provision adjustment is $6,714 (Gross NOL $31,969 at 21%).

The Act preserved the deductibility of intangible drilling costs for federal income tax purposes, which allows the Company to deduct a portion of drilling costs in the year incurred and minimizes current year taxes payable in periods of taxable income. The Act also repealed the corporate alternative minimum tax (AMT) for tax years beginning January 1, 2018 and provides that existing AMT credits can be utilized to offset current federal taxes owed in tax years 2018 through 2020. In addition, 50% of any unused AMT credits are refundable during these years with any remaining AMT credit carryforward being fully refunded in 2021. It is now more likely than not that the benefit of CNX's AMT credits will be realized and as a result the Company has reclassified $102,482 from Deferred Income Taxes to Recoverable Income Taxes on the Consolidated Balance Sheets in anticipation of the AMT refund to be received in 2019. As of December 31, 2018, the Company has a deferred tax asset relating to federal AMT credits of $102,482, a decrease of $85,598 from the prior year that resulted from the anticipated refund of the AMT credits, and certain increases in the AMT due to positions taken on the 2017 federal income tax return and the carryback of prior year NOLS.

During 2018, the valuation allowance relating to federal AMT credits decreased by $12,413 as the Internal Revenue Service (IRS) has announced that refunds of AMT credits are no longer subject to government sequestration.

A valuation allowance on foreign tax credits of $43,194 and $44,402 has also been recorded at December 31, 2018 and 2017, respectively. The foreign tax credits expire at various times between 2021 and 2023. There was no valuation allowance on deferred equity compensation for covered individuals as provided by Section 162(m) as of December 31, 2018. A valuation allowance on deferred equity compensation of $5,957 was recorded as of December 31, 2017. A valuation allowance on charitable contribution carry-forwards of $3,297 and $3,156 has been recorded as of December 31, 2018 and 2017, respectively. The Company's charitable contributions carry-forwards expire at various times between 2019 and 2022.

CNX continues to report, on an after federal tax basis, a deferred tax asset related to state operating losses of $110,339 with a related valuation allowance of $47,964 at December 31, 2018. The deferred tax asset related to state operating losses, on an after tax adjusted basis, was $107,756 with a related valuation allowance of $61,560 at December 31, 2017. A review of positive and negative evidence regarding these state tax benefits concluded that the valuation allowances for various CNX subsidiaries was warranted. These NOLs expire at various times between 2019 and 2038.

The deferred tax assets attributable to the state tax effect of future deductible temporary differences for certain CNX subsidiaries with histories of financial and tax losses were also reviewed for positive and negative evidence regarding the realization of the associated deferred tax assets. There was no valuation allowance recorded at December 31, 2018. A valuation allowance of $9,088 on an after federal tax adjusted basis was recorded at December 31, 2017.

Management will continue to assess the potential for realized deferred tax assets based upon income forecast data and the feasibility of future tax planning strategies and may record adjustments to valuation allowances against deferred tax assets in future periods, as appropriate, that could materially impact net income.

The following is a reconciliation, stated as a percentage of pretax income, of the United States statutory federal income tax rate to CNX's effective tax rate:

	For the Years Ended December 31,					
	2018		**2017**		**2016**	
	Amount	**Percent**	**Amount**	**Percent**	**Amount**	**Percent**
Statutory U.S. federal income tax rate	$230,721	21.0 %	$41,503	35.0 %	$(204,872)	35.0 %
Net Effect of state income taxes	60,814	5.6	15,538	13.1	(20,954)	3.6
Non-controlling Interest	(18,181)	(1.7)	—	—	—	—
Uncertain tax positions	(4,265)	(0.4)	27,359	23.1	1,351	(0.2)
Effect of spin on Federal NOL's	—	—	24,942	21.0	—	—
Accrual to tax return reconciliation	3,028	0.3	(1,147)	(1.0)	(4,564)	0.8
IRS and state tax examination settlements	—	—	—	—	(13,463)	2.3
Effect of change in state valuation allowance	(22,684)	(2.1)	(430)	(0.4)	18,999	(3.2)
Effect of change in federal valuation allowance	(18,110)	(1.7)	(145,772)	(122.9)	184,227	(31.5)
Other deferred adjustments	5,957	0.6	7,616	6.4	—	—
Effect of federal and state rate reductions	(27,429)	(2.5)	(131,784)	(111.1)	—	—
Effect of federal tax credits	1,208	0.1	(19,081)	(16.1)	—	—
Other	4,498	0.4	4,798	4.0	4,873	(0.8)
Income Tax Expense (Benefit) / Effective Rate	$215,557	19.6 %	$(176,458)	(148.9)%	$(34,403)	6.0 %

Under the provisions of Staff Accounting Bulletin 118 (SAB 118), as of December 31, 2017, we had not completed our accounting for all of the enactment-date income tax effects of the Act under ASC 740, Income Taxes, for the remeasurement of deferred tax assets and liabilities. As of December 31, 2018, we have now completed our accounting for all of the enactment-date income tax effects of the Act.

As a result of the Midstream Acquisition on January 3, 2018 as discussed in Note 6 - Acquisitions and Dispositions, the Company obtained a controlling interest in CNX Gathering LLC and, through CNX Gathering's ownership of the general partner, control over CNXM. The financial results for 2018 reflect full consolidation of CNXM’s assets and liabilities. The effective tax rate for the year ended December 31, 2018 reflects a $18,181 reduction in income tax expense due to the non-controlling interest in CNXM’s earnings.

The Act, which, among other things, lowered the U.S. Federal corporate income tax rate from 35% to 21%, repealed the corporate AMT for tax years beginning January 1, 2018, and provided for a refund of previously accrued AMT credits. As discussed above, CNX has credits that are expected to be refunded between 2019 and 2021 because of the Act and monetization opportunities under current law in 2018. The Company recorded a net tax benefit to reflect the impact of the Act as of December 31, 2017, as it is required to reflect the change in the period in which the law is enacted. Largely, the benefits recorded in the period ending December 31, 2017 related to the Act are in recognition of the revaluation of deferred tax assets and liabilities, a benefit of $115,291. The Company's effective tax rate for 2018 and 2017 reflects the release of previously recorded valuation allowances against AMT credit carry-forwards of $12,413 and $154,385, respectively, as those credits will now be able to be monetized under the Act and, according to an IRS announcement, are no longer subject to government sequestration.

The effective tax rate for the year ended December 31, 2018 was lower than the U.S. federal statutory rate primarily due to the effect of the filing of a Federal NOL carryback for 2017 and 2016 resulting in a financial statement benefit of $23,483 through the realization of the Federal NOLs at a 35% tax rate as a carryback versus the current 21% tax rate as a carryforward, the reversal of the AMT credit sequestration valuation allowance, and the release of certain state valuation allowances as a result of a corporate reorganization during the year. The federal NOL carryback claims for 2016 and 2017 are under review by the IRS.

The Act is also a comprehensive tax reform bill containing a number of other provisions that either currently or in the future could impact CNX. The effect of certain limitations effective for the tax year 2018 and forward, specifically related to the deductibility of executive compensation, have been evaluated. The Company anticipates U.S. regulatory agencies will issue further regulations which may alter this estimate. The IRS issued rules during the year pertaining to the application of limitations for executive compensation related to contracts existing prior to November 2, 2017, and provisions in the Act addressing the deductibility of interest expense after January 1, 2018. The Company will continue to refine its estimates to incorporate new or better information as it comes available.

A reconciliation of the beginning and ending gross amounts of unrecognized tax benefits is as follows:

	For the Years Ended December 31,	
	2018	**2017**
Balance at beginning of period	$37,813	$9,103
Increase in unrecognized tax benefits resulting from tax positions taken during current period	—	21,902
Increase in unrecognized tax benefits resulting from tax positions taken during prior periods	2,140	7,474
Reduction in unrecognized tax benefits because of the lapse of the applicable statute of limitations	(8,437)	(666)
Balance at end of period	$31,516	$37,813

If these unrecognized tax benefits were recognized, $31,516 and $29,376 would affect CNX's effective income tax rate for 2018 and 2017, respectively.

In 2018, CNX recognized an increase in unrecognized tax benefits of $2,140 for tax benefits resulting from a revision to our tax position taken on our 2017 federal tax return for the marginal well credit. CNX recognized a reduction to unrecognized tax benefits of $8,437 from a position taken on a state tax return.

CNX recognizes accrued interest related to unrecognized tax benefits in its interest expense. As of December 31, 2018, the Company reported no accrued liability relating to uncertain tax positions in Other Liabilities on the Consolidated Balance Sheets. As of December 31, 2017, the Company reported an accrued liability relating to uncertain tax positions of $644 in Other Liabilities on the Consolidated Balance Sheets. The accrued interest liability includes interest income of $644 and interest expense of $337 recorded in the Company's Consolidated Statements of Income for the years ended December 31, 2018 and 2017, respectively. During the years ended December 31, 2018 and 2017, CNX paid no interest related to income tax deficiencies.

CNX recognizes penalties accrued related to uncertain tax positions in its income tax expense. CNX had no accrued liabilities for tax penalties as of December 31, 2018 and 2017.

CNX and its subsidiaries file federal income tax returns with the United States and income tax returns within various states. With few exceptions, the Company is no longer subject to United States federal, state, local or non-U.S. income tax examinations by tax authorities for the years before 2016. The Joint Committee on Taxation concluded its review of the audit of tax year 2015 on March 21, 2018. The audit resulted in a $108,651 reduction to CNX's NOL, primarily due to a reduction in the depreciation as an offset to the bonus depreciation taken in the 2010-2013 IRS audit. There was no current cash tax impact from the audit.

NOTE 9—ASSET RETIREMENT OBLIGATIONS:

The reconciliation of changes in asset retirement obligations at December 31, 2018 and 2017 is as follows:

	As of December 31,	
	2018	**2017**
Balance at beginning of period	$204,070	$201,006
Obligations Divested (Note 6)	(196,643)	(1,960)
Accretion expense	9,874	5,760
Obligations Incurred	4,795	441
Obligations Settled	(5,323)	(6,875)
Revisions in estimated cash flows	21,781	5,698
Balance at end of period	$38,554	$204,070

NOTE 10—PROPERTY, PLANT AND EQUIPMENT:

	December 31,	
Property, Plant and Equipment	**2018**	**2017**
Intangible Drilling Cost	$4,120,283	$3,849,689
Proved Gas Properties	1,135,411	1,999,891
Gas Gathering Equipment	2,126,895	1,182,234
Unproved Gas Properties	927,667	919,733
Gas Wells and Related Equipment	856,973	834,120
Surface Land and Other Equipment	308,297	309,602
Other Gas Assets	91,902	221,226
Total Property, Plant and Equipment	$9,567,428	$9,316,495
Less: Accumulated Depreciation, Depletion and Amortization	2,624,984	3,526,742
Total Property, Plant and Equipment - Net	$6,942,444	$5,789,753

Amounts below reflect properties where drilling operations have not yet commenced and therefore, are not being amortized for the years ended December 31, 2018 and 2017, respectively. These assets will be amortized using the units-of-production method and reclassified to proved gas properties when placed in service.

	December 31,	
	2018	**2017**
Unproved Gas Properties	$927,667	$919,733
Gas Advance Royalties	12,863	13,220
Total	$940,530	$932,953

As of December 31, 2018 and 2017, property, plant and equipment includes a gross asset related to capital leases of $73,144 and $73,688, respectively. Included in Gas Gathering Equipment is a capital lease for the Jewell Ridge Pipeline of $66,919 at December 31, 2018 and 2017. CNX also maintains a capital lease for vehicles of $6,225 and $6,769 at December 31, 2018 and 2017, respectively, which is included in Other Gas Assets. Accumulated amortization for capital leases was $59,517 and $54,431 at December 31, 2018 and 2017, respectively. Amortization expense for capital leases is included in Depreciation, Depletion and Amortization in the Consolidated Statements of Income. See Note 15–Leases for further discussion of capital leases.

NOTE 11—GOODWILL AND OTHER INTANGIBLE ASSETS:

In connection with the Midstream Acquisition, which closed on January 3, 2018 (See Note 6 - Acquisitions and Dispositions for more information), CNX recorded $796,359 of goodwill and $128,781 of other intangible assets which are comprised of customer relationships.

All goodwill is attributed to the Midstream reportable segment. Changes in the carrying amount of goodwill consist of the following activity:

	Amount
December 31, 2017	$—
Acquisitions	796,359
December 31, 2018	$796,359

The carrying amount and accumulated amortization of other intangible assets consist of the following:

	December 31, 2018
Other Intangible Assets	
Customer Relationships	$128,781
Less: Impairment of Other Intangible Assets	(18,650)
Less: Accumulated Amortization for Customer Relationships	(6,931)
Total Other Intangible Assets, net	$103,200

In May 2018, as a result of the AEA with HG Energy (See Note 6 - Acquisition and Dispositions for more information) CNX determined that the carrying value of a portion of the customer relationship intangible assets exceeded their fair value. Accordingly, CNX recognized an impairment on this intangible asset of $18,650 which consisted of the entire amount that related to a component of the Midstream business that was transferred to HG Energy, and the impairment is included in Impairment of Other Intangible Assets in the Consolidated Statements of Income.

Amortization expense for other intangible assets was $6,931 for the year ended December 31, 2018. There was no such expense for the years ended December 31, 2017 and December 31, 2016.

The customer relationship intangible asset is being amortized on a straight-line basis over approximately seventeen years. The estimated annual amortization expense is expected to approximate $6,552 per year for the next five years.

NOTE 12—REVOLVING CREDIT FACILITIES:

CNX Resources Corporation (CNX)

On March 8, 2018, CNX amended and restated its senior secured revolving credit facility ("Credit Facility"), which expires on March 8, 2023. The CNX Credit Facility increased lenders' commitments from $1,500,000 to $2,100,000 with an accordion feature that allows the Company to increase the commitments to $3,000,000. The initial borrowing base increased from $2,000,000 to $2,500,000, and the letters of credit aggregate sub-limit remained unchanged at $650,000. Effective August 20, 2018, as part of the semi-annual redetermination, the borrowing base was reduced to $2,100,000 primarily based on the sale of substantially all of CNX's Ohio Utica Joint Venture Assets and shallow oil and gas assets (See Note 6 - Acquisitions and Dispositions for additional information). The Credit Facility matures on March 8, 2023, provided that if the aggregate principal amount of our existing 5.875% Senior Notes due in April 2022 and certain other publicly traded debt securities outstanding 91 days prior to the earliest maturity of such debt (such date, the "Springing Maturity Date") is greater than $500,000, then the Credit Facility will mature on the Springing Maturity Date.

The CNX Credit Facility is secured by substantially all of the assets of CNX and certain of its subsidiaries. Fees and interest rate spreads are based on the percentage of facility utilization, measured quarterly. Availability under the Credit Facility is limited to a borrowing base, which is determined by the lenders' syndication agent and approved by the required number of lenders in good faith by calculating a value of CNX's proved natural gas reserves.

The CNX Credit Facility contains a number of affirmative and negative covenants that include, among others, covenants that, except in certain circumstances, limit the Company and the subsidiary guarantors' ability to create, incur, assume or suffer to exist indebtedness, create or permit to exist liens on properties, dispose of assets, make investments, purchase or redeem CNX common stock, pay dividends, merge with another corporation and amend the senior unsecured notes. The Company must also mortgage 80% of the value of its proved reserves and 80% of the value of its proved developed producing reserves, in each case, which are included in the borrowing base, maintain applicable deposit, securities and commodities accounts with the lenders or affiliates thereof, and enter into control agreements with respect to such applicable accounts.

The CNX credit facility contains customary events of default, including, but not limited to, a cross-default to certain other debt, breaches of representations and warranties, change of control events and breaches of covenants.

The CNX Credit Facility also requires that CNX maintain a maximum net leverage ratio of no greater than 4.00 to 1.00, which is calculated as the ratio of debt less cash on hand to consolidated EBITDA, measured quarterly. CNX must also maintain a minimum current ratio of no less than 1.00 to 1.00, which is calculated as the ratio of current assets, plus revolver availability, to current liabilities, excluding borrowings under the revolver, measured quarterly. The calculation of all of the ratios excludes CNXM. CNX was in compliance with all financial covenants as of December 31, 2018.

At December 31, 2018, the CNX credit facility had $612,000 of borrowings outstanding and $198,396 of letters of credit outstanding, leaving $1,289,604 of unused capacity. At December 31, 2017, the Credit Facility had no borrowings outstanding and $239,072 letters of credit outstanding, leaving $1,260,928 of unused capacity.

CNX Midstream Partners LP (CNXM)
On March 8, 2018, CNXM entered into a new $600,000,000 senior secured revolving credit facility that matures on March 8, 2023. The CNXM credit facility replaced its prior $250,000,000 senior secured revolving credit facility. Fees and interest rate spreads under the CNXM credit facility are based on the total leverage ratio, measured quarterly. The CNXM credit facility includes the ability to issue letters of credit up to $100,000 in the aggregate.
The CNXM credit facility contains a number of affirmative and negative covenants that include, among others, covenants that, except in certain circumstances, restrict the ability of CNXM, its subsidiary guarantors and certain of its non-guarantor, non-wholly-owned subsidiaries, except in certain circumstances, to: (i) create, incur, assume or suffer to exist indebtedness; (ii) create or permit to exist liens on their properties; (iii) prepay certain indebtedness unless there is no default or event of default under the facility; (iv) make or pay any dividends or distributions in excess of certain amounts; (v) merge with or into another person, liquidate or dissolve; or acquire all or substantially all of the assets of any going concern or going line of business or acquire all or a substantial portion of another person’s assets; (vi) make particular investments and loans; (vii) sell, transfer, convey, assign or dispose of its assets or properties other than in the ordinary course of business and other select instances; (viii) deal with any affiliate except in the ordinary course of business on terms no less favorable to CNXM than it would otherwise receive in an arm’s length transaction; and (ix) amend in any material manner its certificate of incorporation, bylaws, or other organizational documents without giving prior notice to the lenders and, in some cases, obtaining the consent of the lenders.

In addition, CNXM is obligated to maintain at the end of each fiscal quarter (x) a maximum total leverage ratio of no greater than between 4.75 to 1.00 ranging to no greater than 5.50 to 1.00 in certain circumstances; (y) a maximum secured leverage ratio of no greater than 3.50 to 1.00 and (z) a minimum interest coverage ratio of no less than 2.50 to 1.00. CNXM was in compliance with all financial covenants as of December 31, 2018.

The CNXM credit facility also contains customary events of default, including, but not limited to, a cross-default to certain other debt, breaches of representations and warranties, change of control events and breaches of covenants. The obligations under the facility are secured by substantially all of the assets of CNXM and its wholly-owned subsidiaries. CNX is not a guarantor under the facility.

At December 31, 2018, the CNXM credit facility had $84,000 of borrowings outstanding, and after giving effect to limitations on available capacity per CNXM's revolving credit facility agreement, had borrowings available of $480,000. CNXM had approximately $516,000 of unused capacity at December 31, 2018.

NOTE 13—OTHER ACCRUED LIABILITIES:

December
31,
2018