CNX Resources Corp
Form 10-K
February 07, 2018

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, 2017
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 and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No 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, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act. (Check one):
Large accelerated filer x Accelerated filer 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, 2017, 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 $1,685,654,421.
The number of shares outstanding of the registrant's common stock as of January 22, 2018 is 223,758,284 shares.
DOCUMENTS INCORPORATED BY REFERENCE:
Portions of CNX's Proxy Statement for the Annual Meeting of Shareholders to be held on May 9, 2018, 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.
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.
NGL - Natural gas liquids - those hydrocarbons in natural gas that are separated from the gas as liquids through the proces.
net - “net” natural gas or “net” acres are determined by adding the fractional ownership working interests the Company has in gross wells or acres.
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.
Tcfe - One trillion cubic feet of natural gas equivalents, with one barrel of oil being equivalent to 6,000 cubic feet of gas.

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 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;
- 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 introduce uncertainty that could adversely impact the market for natural gas with potential short and long-term liabilities;
- the risks inherent in natural gas operations, including our reliance upon third-party contractors, being subject to unexpected disruptions, including geological conditions, equipment failure, timing of completion of significant construction or repair of equipment, fires, explosions, accidents and weather conditions that could impact financial results;
- decreases in the availability of, or increases in the price of, required personnel, services, equipment, parts and raw materials to support our operations;
- if natural gas prices remain depressed or drilling efforts are unsuccessful, we may be required to record writedowns of our proved natural gas properties;
- a loss of our competitive position because of the competitive nature of the natural gas industry or overcapacity in this industry impairing 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;
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our inability to collect payments from customers if their creditworthiness declines or if they fail to honor their contracts;

- existing and future government laws, regulations and other legal requirements 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 and related facility integrity management program testing and any related pipeline repair or preventative or remedial measures;
- our ability to find adequate water sources for our use in natural gas drilling, or our ability to dispose of or recycle water used or removed from strata in connection with our gas operations at a reasonable cost and within applicable environmental rules;
- the outcomes of various legal proceedings, including those which are more fully described in our reports filed under the Exchange Act;
- acquisitions and divestitures we anticipate may not occur or produce anticipated benefits;

- risks associated with our debt;
- failure to find or acquire economically recoverable natural gas reserves to replace our current natural gas reserves;
- 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, and lending requirements or regulations;
- 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;
- changes in federal or state income tax laws;
- 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;
- terrorist attacks or cyber-attacks 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;
- we may not achieve some or all of the expected benefits of the separation of CONSOL Energy;
- CONSOL Energy may fail to perform under various transaction agreements that were executed as part of the separation;
- 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 2017 Form 10-K under "Risk Factors," as updated by any subsequent Forms 10-Q, which are on file at the Securities and Exchange Commission.

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PART I

ITEM 1. Business

General

CNX Resources Corporation, (CNX or the Company) is one of the largest independent oil and natural gas companies in the United States and is focused on the exploration, development, production, gathering, processing and acquisition of natural gas properties 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. To effect the separation, CNX's shareholders received one share of CONSOL Energy common stock for every eight shares of CNX's common stock held as of the close of business on November 15, 2017, the record date for the separation and distribution. 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 for all periods presented.

CNX operates, develops and explores for natural gas primarily 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 operating advantage over our competitors. Over the past ten years, CNX's natural gas business has grown by approximately 625% to produce a total of 407.2 net Bcfe in 2017.

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 530,000 net acres in the Marcellus Shale and approximately 652,000 net acres that have Utica Shale potential in Ohio, West Virginia, and Pennsylvania. We also have approximately 2.2 million net acres in our coalbed methane play.

Highlights of our 2017 production include the following:

- Total average production of 1,115,523 Mcfe per day;
- 90% Natural Gas, 10% Liquids; and
- 59% Marcellus, 20% Utica, 16% coalbed methane, and 5% other.

At December 31, 2017, our proved natural gas, NGL, condensate and oil reserves (collectively, "natural gas reserves") had the following characteristics:

- 7.6 Tcfe of proved reserves;
- 93.9% natural gas;
- 58.2% proved developed;
- 95.5% operated; and
- A reserve life ratio of 18.62 years (based on 2017 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 electric power industry generates approximately two-thirds of its output by burning fossil fuels. Because of this we believe that the use of natural gas will continue for many years as one of the principal fuel sources for electricity in the United States. Additionally, we believe that as worldwide economies grow, the demand for electricity from fossil fuels will grow as well, which could result in the expansion of worldwide demand for our natural gas. Natural gas is also the dominant choice for primary heating fuel in the domestic residential sector. CNG (compressed natural gas)-powered vehicles are already in use in many major cities, saving money on fuel and reducing emission levels, while the demand for CNG is expected to grow further through additional fleet conversion to this cleaner-burning fuel. Finally, plentiful natural gas feedstock is creating emerging opportunities for chemicals and plastics manufacturing (in addition to the other uses previously noted) in the United States and abroad as the United States becomes a net exporter of the fuel.

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 natural gas liquid acreage leases within its footprint. Our mission is to empower our team to embrace and drive innovative change that creates long-term value for our shareholders, while enhancing our communities and delivering energy solutions for today and tomorrow. We also will continue to focus on monetization of non-core assets to accelerate value creation and to minimize the shortfall between operating cash flows and our growth capital requirements.

We expect natural gas to become a more significant contributor to the domestic electric generation mix, while fueling industrial growth in the U.S. economy. With the recent growth of natural gas exports to Mexico and Canada and the United States becoming a net exporter of natural gas in 2016, we expect new markets to open up in the coming years. We feel that our significant increases in natural gas production, our reductions in drilling and operating costs and our vast acreage position will allow CNX to take advantage of these markets.

CNX's Capital Expenditure Budget

In 2018, CNX expects capital expenditures of approximately $790-$880 million. The 2018 budget includes $515-$580 million of drilling and completion ("D&C") capital and approximately $275-$300 million of capital associated with land, midstream, and water infrastructure. The 2018 D&C capital budget is allocated approximately 65% to the Marcellus Shale and 35% to the Utica Shale.

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 530,000 net Marcellus Shale acres at December 31, 2017.

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 a large number of acres that have Upper Devonian potential; however, these acres have not been disclosed separately as they generally coincide with our Marcellus acreage.

In December 2016, CNX terminated the 50-50 Joint Venture that was formed in 2011, with Noble Energy, Inc., for the exploration, development, and operation of primarily Marcellus Shale properties in Pennsylvania and West Virginia. As a result of the termination, each party now owns and operates a 100% interest in its properties and wells in two separate operating areas; and each party will now have independent control and flexibility with respect to the scope and timing of future development over its operating area. In June 2017, Noble Energy announced that it has closed on a transaction divesting its upstream assets in northern West Virginia and southern Pennsylvania to HG Energy II Appalachia, LLC, a portfolio company of Quantum Energy Partners.

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 652,000 net Utica Shale acres at December 31, 2017. Approximately 341,000 Utica acres coincide with Marcellus Shale acreage in Pennsylvania, West Virginia, and Ohio.

Coalbed Methane (CBM)

We have the rights to extract CBM in Virginia from approximately 267,000 net CBM acres in Central Appalachia. We produce CBM natural gas primarily from the Pocahontas #3 seam.

We also have the rights to extract CBM in West Virginia, southwestern Pennsylvania, and Ohio from approximately 906,000 net CBM acres. In central Pennsylvania we have the right to extract CBM from approximately 260,000 net CBM acres. In addition, we control approximately 584,000 net CBM acres in Illinois, Kentucky, Indiana, and Tennessee. We also have the right to extract CBM on approximately139,000 net acres in the San Juan Basin in New Mexico. We have no current plans to drill CBM wells in these areas in 2018.

Other Gas

We have the rights to extract natural gas from other shale and shallow oil and gas positions primarily in Illinois, Indiana, Kentucky, New York, Ohio, Pennsylvania, Virginia, and West Virginia from approximately 1,360,000 net acres at December 31, 2017. 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.

Summary of Properties as of December 31, 2017

	Marcellus Segment	Utica Segment	CBM Segment	Other Gas Segment	Total
Estimated Net Proved Reserves (MMcfe)	4,396,130	1,372,261	1,353,366	459,855	7,581,612
Percent Developed	51 %	54 %	72 %	100 %	58 %
Net Producing Wells (including oil and gob wells)	316	76	4,454	8,019	12,865
Net Acreage Position:					
Net Proved Developed Acres	34,010	14,943	259,638	235,346	543,937
Net Proved Undeveloped Acres	28,435	8,449	3,819	—	40,703
Net Unproved Acres(1)	467,365	286,943	1,893,140	1,169,567	3,817,015
Total Net Acres(2)	529,810	310,335	2,156,597	1,404,913	4,401,655

(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 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, our acreage rights and 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, 2017, the number of producing wells, developed acreage and undeveloped acreage:

	Gross	Net(1)
Producing Gas Wells (including gob wells)	17,013	12,853
Producing Oil Wells	171	12
Net Acreage Position:		
Proved Developed Acreage	551,900	543,937
Proved Undeveloped Acreage	41,066	40,703
Unproved Acreage	4,434,714	3,817,015
Total Acreage	5,027,680	4,401,655

(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	4,278,446	3,736,526	25,688
Expiration within 2 years	94,486	43,118	8,447
Expiration beyond 2 years	61,782	37,371	6,568
Total Acreage	4,434,714	3,817,015	40,703

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, 2017, 2016 and 2015, we drilled 90.0, 36.0 and 132.8 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 2017, there were 3.9 net development wells and 1.8 exploratory wells drilled but uncompleted. There were no dry development wells in 2017, 2016, or 2015. As of December 31, 2017, there are 13.0 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,		
	2017	2016	2015
Marcellus segment	9.0	—	44.0
Utica segment	17.0	13.0	15.8
CBM segment	64.0	23.0	73.0
Other Gas segment	—	—	—
Total Development Wells (Net)	90.0	36.0	132.8

Exploratory Wells (Net)

There were 4.0 net exploratory wells drilled during the year ended December 31, 2017. There were no exploratory wells drilled during the year ended December 31, 2016 and 2.5 net exploratory wells drilled during the year ended December 31, 2015. As of December 31, 2017, there are 1.8 net exploratory wells in process. The following table illustrates the exploratory wells drilled by well classification type:

	For the Year Ended December 31,								
	2017			2016			2015		
	Producing	Dry	Still Eval.	Producing	Dry	Still Eval.	Producing	Dry	Still Eval.
Marcellus segment	—	—	—	—	—	—	—	—	—
Utica segment	2.2	—	1.8	—	—	—	2.5	—	—
CBM segment	—	—	—	—	—	—	—	—	—
Other Gas segment	—	—	—	—	—	—	—	—	—

Total Exploratory Wells (Net)	2.2	—	1.8	—	—	—	2.5	—	—

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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,		
	2017	2016	2015
Proved developed reserves	4,409,065	3,683,302	3,697,152
Proved undeveloped reserves	3,172,547	2,568,346	1,945,837
Total proved developed and undeveloped reserves(1)	7,581,612	6,251,648	5,642,989

(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)		
	2017	2016	2015
Future net cash flows	$7,841	$2,419	$2,500
Total PV-10 measure of pre-tax discounted future net cash flows (1)	$4,140	$1,559	$1,659
Total standardized measure of after tax discounted future net cash flows	$3,131	$955	$1,019

(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,		
	2017	2016	2015
	(Dollars in millions)		
Future cash inflows	$19,262	$11,303	$11,838
Future production costs	(7,234)	(5,851)	(6,585)
Future development costs (including abandonments)	(1,711)	(1,550)	(1,220)
Future net cash flows (pre-tax)	10,317	3,902	4,033
10% discount factor	(6,177)	(2,343)	(2,374)
PV-10 (Non-GAAP measure)	4,140	1,559	1,659
Undiscounted income taxes	(2,476)	(1,483)	(1,534)
10% discount factor	1,467	879	894
Discounted income taxes	(1,009)	(604)	(640)
Standardized GAAP measure	$3,131	$955	$1,019

Gas Production

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

	For the Year Ended December 31,		
	2017	2016	2015
Natural Gas			
Sales Volume (MMcf)			
Marcellus	209,687	186,812	149,332
Utica	70,708	71,277	38,344
CBM	65,373	68,971	74,910
Other	19,125	21,693	24,701
Total	364,893	348,753	287,287
NGL			
Sales Volume (Mbbls)			
Marcellus	4,604	3,922	3,175
Utica	1,851	2,787	2,354
Other	1	1	1
Total	6,456	6,710	5,530
Oil and Condensate			
Sales Volume (Mbbls)			
Marcellus	346	360	650
Utica	204	470	627
Other	39	65	88
Total	589	895	1,365
Total Sales Volume (MMcfe)			
Marcellus	239,387	212,504	172,280
Utica	83,038	90,820	56,229
CBM	65,373	68,971	74,910
Other	19,368	22,092	25,238
Total	407,166	394,387	328,657

*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.

CNX expects 2018 annual natural gas production volumes of 520-550 Bcfe, or an approximately 31% annual increase, compared to 2017 volumes, based on the midpoint of guidance.

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,		
	2017	2016	2015
Average Sales Price - Gas (Mcf)	$2.59	$1.92	$2.17
(Loss) Gain on Commodity Derivative Instruments - Cash Settlement- Gas (Mcf)	$(0.11)	$0.70	$0.68
Average Sales Price - NGLs (Mcfe)*	$4.03	$2.42	$2.05
Average Sales Price - Oil (Mcfe)*	$7.56	$6.15	$7.99
Average Sales Price - Condensate (Mcfe)*	$6.59	$4.58	$4.42
Total Average Sales Price (per Mcfe) Including Effect of Derivative Instruments	$2.66	$2.63	$2.81
Total Average Sales Price (per Mcfe) Excluding Effect of Derivative Instruments	$2.76	$2.01	$2.22
Average Lifting Costs Excluding Ad Valorem and Severance Taxes (per Mcfe)	$0.22	$0.24	$0.37
Average Sales Price - NGLs (Bbl)	$24.18	$14.52	$12.30
Average Sales Price - Oil (Bbl)	$45.36	$36.90	$47.94
Average Sales Price - Condensate (Bbl)	$39.54	$27.48	$26.52

*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 $0.17 per Mcfe, $0.09 per Mcfe, and $0.05 per Mcfe for 2017, 2016, and 2015, respectively, to average gas sales prices. CNX expects to continue to realize a liquids uplift benefit as additional wells are brought online 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 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. The notional volumes associated with these gas swaps represented approximately 264.9 Bcf of our produced gas sales volumes for the year ended December 31, 2016 at an average price of $3.04 per Mcf. As of January 15, 2018, we expect these transactions will represent approximately 388.6 Bcf of our estimated 2018 production at an average price of $2.77 per Mcf, 273.0 Bcf of our estimated 2019 production at an average price of $2.74 per Mcf, 198.3 Bcf of our estimated 2020 production at an average price of $2.78 per Mcf, approximately 166.5 Bcf of our estimated 2021 production at an average price of $2.62 per Mcf, and approximately 153.4 Bcf of our estimated 2022 production at an average price of $2.83 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 17 - Derivative Instruments in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K.

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, CNX has acquired extensive gathering assets. CNX now owns or operates approximately 5,000 miles of natural gas gathering pipelines as well as 250,000 horsepower of compression, of which, approximately 75% is wholly owned with the balance being leased. Along with this compression capacity, CNX owns and operates a number of natural gas processing facilities. This infrastructure is capable of delivering approximately 750 billion cubic feet per year of pipeline quality gas.

On January 3, 2018, CNX closed its previously announced acquisition of Noble Energy's (Noble) 50% membership interest in CONE Gathering LLC (CONE or CONE Gathering), 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 21 - Subsequent Event 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 operated this equity affiliate. Subsequent to the acquisition, CNX is the single sponsor of CNXM, and beginning in the first quarter of 2018 CNX Gathering will be fully consolidated into the Company's financial statements. 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.

In the Utica Shale, we and our joint venture partner, Hess, primarily contract with third-parties for 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. In the near term, if appropriate, CNX also plans to optimize and/or release 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 the capacity to move our production to the major gas markets, 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 production areas and has operational and contractual flexibility to potentially convert a portion of currently processed wet gas volumes to be marketed as dry gas volumes.

CNX has the advantage of having gas production from CBM, which can be lower Btu than pipeline specification, as well as higher Btu Marcellus and Utica shale production. These types of gas can be complementary by reducing and in some cases eliminating the need for the costly processing of CBM. In addition, our lower Btu CBM and dry Marcellus and Utica production offer an opportunity to blend ethane back into the gas stream when pricing or capacity in ethane markets dictate. In developing a diversified approach to managing ethane, CNX has entered into ethane supply agreements and regularly assesses future outlet opportunities with ethane customers and midstream companies. These different gas types allow us more flexibility in bringing Marcellus and Utica shale wells on-line at qualities that meet interstate pipeline specifications.

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 nine months of 2017. The EIA reported 552,506 producing natural gas wells in the United States at December 31, 2016 (the latest year for which government statistics are available), which is approximately four percent lower than 2015.

CNX expects natural gas 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, based on preliminary results, natural gas represented 32% of U.S. electricity generation during 2017 compared with 34% in 2016. With the recent growth of natural gas exports to Mexico, increased liquefied natural gas exports, and declining pipeline imports from Canada, the U.S. became a net exporter of gas in 2016 and is projected by the EIA to be a net exporter of gas for 2017 and 2018. CNX also 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 expects overall demand for U.S. natural gas to be 4.3% higher in 2018 compared with 2017. Our increasing gas production will allow CNX to participate in these growing markets.

CNX gas operations are primarily located in the eastern United States. The gas market is highly fragmented and not dominated by any single producer. We believe that competition within our market is based primarily on natural gas commodity trading fundamentals and 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.

Other Operations

CNX provides other services, including both land and water services, to both our own operations and to others.

Non-Core Mineral Assets and Surface Properties

CNX owns significant natural gas assets that are not in our short 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, doing business as CONVEY Water Systems LLC, 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, CONVEY Water Systems 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, 2017, CNX had 561 employees, none of which 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, 2017, 2016 and 2015 is included in Note 19 - 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.

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Laws and Regulations

Overview

Our natural gas operations are subject to various types of federal, state and local laws and regulations. Regulations relating to our operations include permitting, bonding and other licensing requirements; 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 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 disbursement of taxes; gathering of natural gas production in certain circumstances; air quality standards; protection of wetlands; crossing of waterways; endangered plant and wildlife protection; use of public roads; and employee health and safety. Numerous governmental permits, authorizations and approvals under these laws and regulations are required for natural gas operations. Lastly, the electric power generation industry is subject to extensive regulation regarding the environmental impact of its power generation activities, which could affect demand for our natural gas.

We endeavor to conduct our natural gas 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 natural gas operations can and do occur. The possibility exists that new legislation or regulations may be adopted which would have a significant impact on our natural gas operations or our customers' ability to use our natural gas and may require us or our customers to change their operations significantly or incur substantial costs.

In July 2010, U.S. Congress enacted the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act), which established federal oversight and regulation of the over-the-counter derivative market and entities, such as the Company, that participate in that market. The Dodd-Frank Act requires the Commodities Futures Trading Commission (CFTC), the SEC and other regulatory agencies to promulgate rules and regulations implementing this legislation. As of the filing date of this Annual Report on Form 10-K, the CFTC has finalized certain regulations that impose regulatory obligations on all market participants, including the Company, while other regulations remain to be finalized or implemented. Because certain CFTC rules relevant to natural gas hedging activities have yet to be promulgated, it is not possible at this time to predict the extent of the impact of the regulations on the Company’s hedging program or regulatory compliance obligations. The Company has experienced, and expects to continue to experience, increased compliance costs in connection with changes to current market practices as participants continue to adapt to a changing regulatory environment.

Environmental Laws

CNX has established protocols for ongoing assessments to identify potential environmental exposures. These assessments evaluate compliance with laws and regulations and other industry and internal best management practices, and include evaluation of compliance by waste management facilities and other third-party service providers.

Clean Air Act and Related Regulations. The federal Clean Air Act (CAA) 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. The federal CAA 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, hydraulic fracturing and completion processes, and fugitive emissions. 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 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 restrict our ability to produce.

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. On August 16, 2012, the U.S. Environmental Protection Agency (EPA) published final revisions to the New Source Performance Standards (NSPS) to regulate emissions of volatile organic compounds (VOCs) and sulfur dioxide (SO_2) from various oil and gas exploration, production, processing and transportation facilities. Additionally, revisions were made to the National Emission Standards for Hazardous Air Pollutants (NESHAPS) to further regulate emissions from the oil and natural gas production sector and the transmission and storage of natural gas. Section 111 of the CAA authorized the EPA to develop technology based standards which apply to specific categories of stationary sources. On June 3, 2016, the EPA finalized updates to the final New Source Performance Standards (NSPS) that created new standards for the regulation of methane and VOC emission sources. The rule includes requirements for new fugitive emission and leak detection testing and reporting requirements. Also on June 3, 2016, the EPA published the final Source Determination Rule which clarified the use of the term “adjacent” in determining Title V air permitting requirements as they apply to the oil and natural gas industry for major sources of air emissions. On August 1, 2016 these updates to the NSPS were challenged in the D.C. Circuit Court of Appeals by industry and state associations and a request for administrative reconsideration was also filed. Additionally, 15 states filed suit and asked the Court of Appeals to review the need for the changes.

The CAA requires the EPA to set National Ambient Air Quality Standards (NAAQS) for certain pollutants and the CAA identifies two types of NAAQS. Primary standards provide public health protection, including protecting the health of "sensitive" populations such as asthmatics, children, and the elderly. Secondary standards provide public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings. On October 1, 2015, the EPA finalized the NAAQS for ozone pollution and reduced the limit to 70 parts per billion (ppb) from the previous 75 ppb standard. The final rule could have a large impact on the oil and gas industry as states would be required to update their permitting standards to meet these potentially unachievable limits. Six states have now filed a petition for review in the Court of Appeals for the D.C. Circuit.

On July 6, 2011, the EPA finalized a rule known as the Cross-State Air Pollution Rule (CSAPR). CSAPR regulates cross-border emissions of criteria air pollutants such as SO_2 and NO_X, as well as byproducts, fine particulate matter ($PM_{2.5}$) and ozone by requiring states to limit emissions from sources that "contribute significantly" to noncompliance with air quality standards for the criteria air pollutants. If the ambient levels of criteria air pollutants are above the thresholds set by the EPA, a region is considered to be in "nonattainment" for that pollutant and the EPA applies more stringent control standards for sources of air emissions located in the region. In April 2014, the Supreme Court reversed a decision of the D.C. Circuit Court of Appeals that vacated the rule. Following remand and briefing the D.C. Circuit Court of appeals, in October 2014, granted a motion to lift a stay of the rule and allow the EPA to modify the CSAPR compliance deadline by three-years, setting the stage for issuance of the proposed rule. Implementation of CSAPR Phase 1 began in 2015, with Phase 2 scheduled to begin in 2017. On September 7, 2016, the EPA finalized an update to the CSAPR for the 2008 ozone NAAQS by issuing the final CSAPR Update. Starting in May 2017, this rule will reduce summertime (May - September) NO_X emissions from power plants in 22 states in the eastern United States.

On January 8, 2014, the EPA re-proposed NSPS for CO_2 for new fossil fuel fired power plants and rescinded the rules that were proposed on April 12, 2012. On September 20, 2013, the EPA issued a new proposal to control carbon emissions from new power plants. Under the Clean Power Plan (CPP) proposal, the EPA would establish separate NSPS for CO_2 emissions for natural gas-fired turbines and coal-fired units. However, in April 2017, the U.S. Court of Appeals for the D.C. Circuit granted the EPA’s motion to hold a pending appeal in abeyance while the EPA undertakes a review of the proposal. The proposed “Carbon Pollution Standard for New Power Plants” replaces the earlier proposal released by the EPA in 2012. On August 3, 2015, the EPA finalized the Carbon Pollution Standards to cut carbon emissions from new, modified and reconstructed power plants, which would have become effective on October 23, 2015.

Climate Change. 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. Additional regulation could also lead to permitting delays and additional monitoring and administrative requirements, as well as to impacts on electricity generating operations.

On November 30, 2016, the EPA finalized amendments to the Petroleum and Natural Gas Systems source category (Subpart W) of the Greenhouse Gas Reporting Program (GHGRP). This final rule adds new monitoring methods for detecting leaks from oil and gas equipment in the petroleum and natural gas systems source category consistent with the leak detection methods in the NSPS. The action also adds emission factors for leaking equipment to be used in conjunction with these monitoring methods to calculate and report greenhouse gas (GHG) emissions resulting from equipment leaks. The NSPS final rule would add reporting of GHG emissions from certain gathering and boosting systems, completions and workovers of oil wells using hydraulic fracturing, and blowdowns of natural gas transmission pipelines.

Clean Water Act. The federal Clean Water Act (CWA) and corresponding state laws affect our natural gas operations by regulating discharges into surface waters. Permits requiring regular monitoring and compliance with effluent limitations and reporting requirements govern the discharge of pollutants into regulated waters. The CWA and corresponding state laws include requirements for: improvement of designated "impaired waters" (i.e., not meeting state water quality standards) through the use of effluent limitations; anti-degradation regulations which protect state designated "high quality/exceptional use" streams by restricting or prohibiting discharges; stormwater controls; and requirements to dispose of produced wastes and other oil and gas wastes at approved disposal facilities. These requirements impact the development of infrastructure, well-drilling, and hydraulic fracturing operations. The CWA and similar state laws provide for civil, criminal and administrative penalties for unauthorized discharges of pollutants or reportable quantities of oil and/or other hazardous substances. The Spill Prevention, Control and Countermeasure (SPCC) requirements of the CWA apply to operations that use or produce fluids of threshold quantities and require the implementation of plans to prevent and contain spills. These requirements (or changes to current regulations) may cause CNX to incur significant additional costs that could adversely affect our operating results, financial condition and cash flows.

CNX utilizes pipelines extensively for its natural gas and water businesses. Mitigation permits from the Army Corps of Engineers (ACOE) are typically required for certain impacts these pipelines cause to streams and wetlands, including the crossing of such streams and wetlands. Any expansion of the scope of regulation of pipeline development to include previously non-jurisdictional streams, wetlands and waters, could adversely affect our operating results, financial condition and cash flows.

Endangered Species Act. The Endangered Species Act and related state regulation protect plant and animal species that are threatened or endangered. 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. On April 8, 2016, The U.S. Department of Transportation (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published in the Federal Register a Notice of Proposed Rule Making (NPRM) that would significantly modify existing regulations related to reporting, impact, design, construction, maintenance, operations and integrity management of gas transmission and gathering pipelines. The proposed rule addresses four congressional mandates and six recommendations by the National Transportation Safety Board. The proposed rule broadens the scope of safety coverage both by adding new assessment and repair criteria for gas transmission pipelines, and by expanding these protocols to include pipelines not formerly regulated by the federal standards. This means extending regulatory requirements to transmission and gathering pipelines of eight inches and greater in rural class 1 areas, which could increase time frames and cost to complete projects. It is unclear what action may be taken on this proposal in the new administration. Additionally, certain states, such as West Virginia, also maintain jurisdiction over intrastate natural gas lines.

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

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.

Other State and Local Laws Related to Our Natural Gas Business

Regulation Affecting Gas Operations. Our natural gas operations are also subject to regulation at the state and in some cases, county, municipal and local governmental levels. Such regulation includes requiring permits for the siting and construction of well pads, impoundments, tanks and roads; pooling and unitizations; drilling of wells; bonding requirements; protection of ground water and surface water resources and protection of drinking water supplies; the method of drilling and casing wells; the surface use and restoration of well sites; gas flaring; the plugging and abandoning of wells; the disposal of fluids used in connection with operations; and natural gas operations producing coalbed methane in relation to active mining. A number of states have either enacted new laws or may be considering the adequacy of existing laws affecting gathering rates and/or services. Other state regulation of gathering facilities generally includes various safety, environmental and in some circumstances, nondiscriminatory take requirements but does not generally entail rate regulation. Thus, natural gas gathering may receive greater regulatory scrutiny of state agencies in the future. Our gathering operations could be adversely affected should they be subject in the future to increased state regulation of rates or services, although we do not believe that they would be affected by such regulation any differently than other natural gas producers or gatherers. However, these regulatory burdens may affect profitability, and we are unable to predict the future cost or impact of complying with such regulations.

Regulation of Horizontal Drilling. State regulations for horizontal well drilling and well site construction have been proposed and finalized. In September 2015, Pennsylvania published a final rulemaking on the revisions to the Environmental Protection Performance Standards at Oil and Gas Well Sites (Chapters 78 and 78a). Chapter 78 rules affecting conventional drillers were eliminated under SB279, and may be readdressed by the Pennsylvania Department of Environmental Protection in 2018. Chapter 78a rules are the subject of pending litigation, with oral argument before the Pennsylvania Supreme Court in October 2017. Ohio passed Horizontal Well Site Construction Rules which became effective in July 2015. Ohio is also in the process of reviewing and possibly adopting additional horizontal development rules. Additionally, West Virginia adopted Rules Governing Horizontal Well Development.

Ownership of Mineral Rights. CNX acquires ownership or leasehold rights to oil and 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. However, our ownership of certain oil and gas rights, particularly some of the rights we acquired in 2010, as part of an acquisition, may be less developed. As we continue to conduct our standard review of land records and confirm title in anticipation of development, we expect that adjustments to our ownership position (either increases or decreases) will be required.

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. We generally will not commence operations on a property until we have cured any material title defects on such property. We are typically responsible for the cost of curing any title defects. In addition, the acquisition of the necessary rights to affect such a cure may not be feasible in some cases. 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, and 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 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. An extended decline in the prices we receive for our natural gas and natural gas liquids 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 natural gas liquids. Natural gas, natural gas liquids, 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, natural gas liquids, oil and condensate.
In particular, while demand for natural gas has recovered to pre-recession levels, 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 recovered somewhat during 2013 and the first quarter of 2014, they again significantly declined in the latter part of 2014 and have remained at depressed levels since 2015.
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 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 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. These include reduced cash flow, which decreases funds available for capital expenditures to replace reserves or increase production. For example, the low natural gas prices continuing from 2014 through 2015, resulted in our decreasing 2016 and 2017 capital expenditures and the drilling of new shale wells. 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 natural gas liquids, condensate and/or oil. The prices for natural gas liquids, 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 natural gas liquids has led to a decline of over 30% since 2014 in the uplift we receive, on an Mcfe equivalent basis when excluding hedging impact, from natural gas liquids. Our results of operation may be adversely affected by a continued depressed level of, or further downward fluctuations in, natural gas liquids,

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 which 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;
- the costs, availability and capacity of transportation infrastructure;
- proximity and capacity of natural gas pipelines and other transportation facilities; and
- the impact of domestic and foreign governmental laws and regulations, including environmental and climate change regulations and delays in the receipt of, failure to receive, failure to maintain or revocation of necessary governmental permits.

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 natural gas liquids, and any decrease in availability of third-party 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 natural gas liquids 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 natural gas liquids are reduced because of transportation or processing constraints, our revenues will be reduced and our unit costs will also increase. If pipeline quality standards change, we might be required to install additional processing equipment which could increase our costs. The pipeline 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 materially adversely affect 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.

Additionally, 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 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 41% of our 2017 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 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 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 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 present value of future net cash flows from our proved reserves is 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;
- changes in governmental regulations and taxation;
- the amount and timing of actual production;
- future prices and our hedging position;
- future operating costs; 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, 2017 would decrease from $4.1 billion to $3.9 billion.

Each of the factors which impacts 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.

Drilling 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...” 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 and obtain all of the permits required to drill the wells;
- 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; 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. 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 economic, 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 will be 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 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 necessary to complete the drilling unit, 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 materially adverse effect on our business and results of operations.

Regulation of greenhouse gas emissions 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.

While climate change legislation in the U.S. is unlikely in the next several years, 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 and methane.

The EPA, under the Climate Action Plan, has elected to regulate GHGs under the Clean Air Act (CAA) to limit emissions of carbon dioxide (CO2) from natural gas-fired power plants. On September 20, 2013, the EPA re-proposed New Source Performance Standards (NSPS) for CO2 from new power plants and on June 2, 2014, the EPA re-proposed NSPS for CO2 from existing and modified/reconstructed power plants, which rescinded the rules that were originally proposed in 2012. 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 another proposed rulemaking related to CO2 emissions, on June 2, 2014, the EPA proposed the Clean Power Plan Rule to cut carbon emissions from existing power plants. Under this proposed rule, the EPA would create emission guidelines for states to follow in developing plans to address greenhouse gas emissions from existing fossil fuel-fired electric generating units. Specifically, the EPA is proposing state-specific rate-based goals for CO2 emissions from the power sector, as well as guidelines for states to follow in developing plans to achieve the state-specific goals. On August 3, 2015, the EPA finalized the Clean Power Plan Rule to cut carbon pollution from existing power plants, which became effective on December 22, 2015. Numerous petitions challenging the Clean Power Plan Rule have been consolidated into one case, West Virginia v. EPA. While the litigation is still ongoing at the circuit court level, a mid-litigation application to the Supreme Court resulted in a stay of the Clean Power Plan Rule. On September 27, 2016, an en banc panel of the U.S. Court of Appeals for the D.C. Circuit heard oral arguments in the case. In April 2017, the D.C. Circuit granted the EPA’s motion to hold the case in abeyance while the EPA undertakes its review of the regulations.

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.

As part of the Obama administration's initiative to reduce methane emissions from the oil and natural gas industry, the EPA adopted rules to control volatile organic compound emissions from certain oil and gas equipment and operations. In June 2017, the EPA issued a 90-day stay of certain requirements under the methane rule. The stay was vacated in July 2017 by the U.S. Court of Appeals for the D.C. Circuit. In the interim, in July 2017 the EPA issued a proposed rule that would stay the methane rule for two years, but this rule is not yet final, is subject to public notice and comment and may be subject to legal challenges.

Additionally, applicability of CNX and CNXM facilities under the CAA, as well as state sponsored permitting programs are subject to regulatory uncertainty and therefore present risk, including hitting production objectives, and cost for controls and compliance. Some states in which we operate are contemplating measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and potential cap-and-trade programs. Most of these types 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.

Environmental regulations 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 develop and implement species-specific protection and enhancement plans to avoid or minimize impacts to endangered species or their habitats. 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. On April 21, 2014 the EPA published a proposed rule called “Definition of ‘Waters of the United States’ (WoUS) Under the Clean Water Act.” The proposal would expand the scope of the CWA to include previously non-jurisdictional streams, wetlands, and waters, making these areas jurisdictional inter-coastal waters of the U.S. In February 2015 the EPA and ACOE issued a memorandum of understanding to withdraw the WoUS Interpretive Rule. The EPA published the latest version of the WoUS rule (the Clean Water Rule) on June 29, 2015, which was to become effective on August 28, 2015. However, on August 27, 2015, the District Court of North Dakota blocked implementation of the rule in 13 states. On October 9, 2015, the Court of Appeals for the Sixth Circuit blocked implementation of the rule nationwide. The Trump administration has proposed replacing the October 2015 definition with the prior definition. Additionally, in January 2017, the U.S. Supreme Court agreed to decide whether the federal court of appeals or federal district courts have jurisdiction. Oral argument was heard in October 2017, and a decision is expected in calendar year 2018. If the EPA moves forward with implementation of the 2015 rule, or if states make any similar changes to their regulatory programs, this could lead to additional mitigation costs for us and CNXM, and severely limit our and CNXM’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.

Our operations are subject to operating risks, including our reliance upon third-party contractors, which 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 hazards, which occur in our operations 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 operating 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 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 operating risks that may have a significant impact on our natural gas operations include:

- unexpected drilling conditions;
- title problems;
- pressure or irregularities in geologic formations;
- equipment failures or repairs;
- fires, ruptures, landslides, mine subsidence, explosions or other accidents;
- adverse weather conditions;
- reductions in natural gas prices;
- pressure or irregularities in formations;
- security breaches or terroristic acts;
- damage to pipelines, compressor stations, pump stations, related equipment and surrounding properties caused by design, installation, construction materials or operational flaws, natural disasters, acts of terrorism and acts of third parties;
- lack of adequate capacity for treatment or disposal of waste water generated in drilling, completion and production operations;
- environmental conditions, including contamination from surface spillage of fluids used in well drilling, completion or operation including fracturing fluids used in hydraulic fracturing of wells, leaks of natural gas or condensate or losses of natural gas or condensate as a result of the malfunction of, or other disruptions associated with, equipment or facilities or other contamination of groundwater or the environment resulting from our use of such fluids;
- delays in the issuance of permits at the state or local level and the resolution of regulatory concerns; and
- lack of availability or high cost of drilling rigs, other field services, personnel and equipment.

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 which prevents delivery of natural gas to a customer and which is not excusable as a force majeure event under our supply agreement, could result in economic penalties, suspension or cancellation of shipments 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 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.
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 2017 due to the oversupply of gas in our markets, we made payments under these types of contracts of approximately $40 million 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.

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 a supply of 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.

If natural gas prices remain depressed or drilling efforts are unsuccessful, we may be required to record writedowns of our proved natural gas properties.

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.

Competition 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 and midstream industries are intensely competitive with companies from various regions of the United States. 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. 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. 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 their existing systems, its ability to expand its existing systems, contractual limitations 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 materially 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 and 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 our ability to collect our trade receivables;
- 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 15, 2018, we expect these transactions will represent approximately 388.6 Bcf of our estimated 2018 production at an average price of $2.77 per Mcf, 273.0 Bcf of our estimated 2019 production at an average price of $2.74 per Mcf, 198.3 Bcf of our estimated 2020 production at an average price of $2.78 per Mcf, approximately 166.5 Bcf of our estimated 2021 production at an average price of $2.62 per Mcf, and approximately 153.4 Bcf of our estimated 2022 production at an average price of $2.83 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, or reduce our use of hedging arrangements in the future, 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.

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;
- the counterparties to our contracts fail to perform the 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.

Our ability to collect payments from our customers could be impaired if their creditworthiness declines or if they fail to honor their contracts with us.

Our ability to receive payment for natural gas sold and delivered depends on the continued creditworthiness of our customers. Many utilities have sold their power plants to non-regulated affiliates or third-parties that may be less creditworthy, thereby increasing the risk we bear with respect to potential payment default. These new power plant owners may have credit ratings that are below investment grade. If the creditworthiness of our customers or their ability to pay declines significantly, our business could be adversely affected. Our inability to collect payment from counterparties to our sales contracts may have a materially adverse effect on our business, financial condition, results of operations and cash flows.

Existing and future government laws, regulations and other legal requirements 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 changes may affect, among other things, the pricing or marketing of natural gas production. 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 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 the Public Utility Commission (PUC) oversight of Class I gathering lines, as well as requiring standards and fees associated with 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 our midstream activities, requiring changes in reporting, as well as increased costs.

We may incur significant costs and liabilities as a result of pipeline and related facility integrity management program testing and any related pipeline repair or preventative or remedial measures.

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.

The 2011 Pipeline Safety Act, among other things, increased the maximum civil penalty for pipeline safety violations and directed the Secretary of Transportation to promulgate rules or standards relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation, and testing to confirm the material strength of pipe operating above 30% of specified minimum yield strength in high consequence areas. In 2017, PHMSA adopted new rules increasing the maximum administrative civil penalties for violation of the pipeline safety laws and regulations to $209,002 per violation per day, with a maximum of $2,909,022 for a related series of violations. Should our or CNXM's operations fail to comply with PHMSA or comparable state regulations, we could be subject to substantial penalties and fines. PHMSA has also published notices and advanced notices of proposed rulemaking to solicit comments on the need for changes to its safety regulations, including whether to extend the integrity management program requirements to additional types of facilities, such as gathering pipelines and related facilities. In January 2017, in the final week of the Obama

Administration, 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, including periodic integrity assessments and leak detection for pipelines outside of high consequence areas, inspections of pipelines after extreme weather events, expanded reporting, and more stringent integrity management repair and data collection requirements. Due to the change in Presidential administrations, PHMSA's final hazardous liquid pipeline safety rule was never published in the Federal Register and has not yet taken effect. PHMSA is expected to finalize its hazardous liquid pipeline safety rule this year. 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 that are currently exempt from PHMSA regulations. PHMSA 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. Additionally, in April 2016, PHMSA published in the Federal Register a Notice of Proposed Rule Making ("NPRM") that would significantly modify existing regulations related to reporting, impact, design, construction, maintenance, operations and integrity management of gas transmission and gathering pipelines. The proposed rule addresses four congressional mandates and six recommendations by the National Transportation Safety Board to broaden the scope of safety coverage by adding new assessment and repair criteria for gas transmission pipelines, and by expanding these protocols to include pipelines not formerly regulated by the federal standards. This includes extending regulatory requirements to transmission and gathering pipelines of eight inches and greater in rural Class I areas. Compliance with the rule, as proposed, may prove challenging and costly for operators of older pipelines due to the difficulty of locating historic records. 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 the us and CNXM remains uncertain until the rulemaking is finalized. PHMSA is expected to finalize its natural gas pipeline safety rule this year. The adoption of regulations that apply more comprehensive or stringent safety standards 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 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 commercial 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. 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 water, 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, could increase our costs and delay our operations, which will adversely impact our cash flow 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 three 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 coastal communities against oil, coal and other 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.

We do not 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 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. 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

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, 2017, our total long-term indebtedness was approximately $ 2.22 billion of which approximately $1.71 billion was under our 5.875% senior unsecured notes due 2022 plus $4 million of unamortized bond premium, $500 million was under our 8.000% senior unsecured notes due 2023 less $5 million of unamortized bond discount, and $20 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 gas and coal reserves or other general corporate requirements;
- limiting our flexibility in planning for, or reacting to, changes in our business and in the coal and natural gas industries;
- 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.

Our senior secured credit facility and the indentures governing our 5.875% and 8.000% 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% and 8.000% 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 minimum interest coverage ratio, and a minimum current ratio, as defined therein. Our senior secured credit agreement and the indentures governing our 5.875% and 8.000% 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 $250.0 million revolving credit facility subjects it 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, we 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 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% and 8.000% senior unsecured notes restrict our ability to sell assets and use 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.

Failure to find or acquire economically recoverable natural gas reserves to replace our current natural gas reserves will cause our 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, 2017, 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 and exploiting 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.
Our lenders use the loan value of our proved natural gas reserves to determine the borrowing base under our $1.5 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, and lending requirements or regulations. Significant reductions in our borrowing base below $1.5 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 $1.5 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 $2.0 billion. Our borrowing base is redetermined by the lenders twice per year, and the next scheduled borrowing base redetermination is expected to occur in May 2018. 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 decrease our borrowing base. Please read: "Risk Factors - We face uncertainties in estimating our economically recoverable natural gas and coal 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 $1.5 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.

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 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.

Changes in federal or state income tax laws, particularly in the area of intangible drilling costs, could cause our financial position and profitability to deteriorate.

The passage of legislation or any other similar 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 severance taxes or increased severance 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.

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 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 each of the Growth Systems and 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 gathering agreement with us, CNXM's largest customer, as amended, includes minimum well commitments; however, that gas gathering agreement and the gas gathering agreements with 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 develop their properties in the areas covered by CNXM’s acreage dedications, and determine that it is more attractive to direct their capital spending and resources to other areas, such decreases in development of reserves by CNXM customers could result in reduced volumes serviced by CNXM and a commensurate decline in revenues and cash flows.

We cannot assure you 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.

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

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

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

As dependence on digital technologies has increased, cyber incidents, including deliberate attacks or unintentional events, have also increased. A cyber-attack could include gaining unauthorized access to digital systems for purposes of misappropriating assets or sensitive information, corrupting data, or causing operational disruption, or result in denial-of-service on websites. 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, and those of our business partners may become the target of cyber-attacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period.

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

- a cyber-attack on a vendor or service provider could result in supply chain disruptions which could delay or halt development of additional infrastructure, effectively delaying the start of cash flows from the project;
- a cyber-attack on our facilities may result in equipment damage or failure;
- a cyber-attack on midstream or downstream pipelines could prevent our product from being delivered, resulting in a loss of revenues;
- a cyber-attack on a communications network or power grid could cause operational disruption resulting in loss of revenues;
- 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 controls and processes, including globally incorporating a risk-based cyber security framework, to monitor and mitigate security threats and to increase security for our information, facilities and infrastructure is costly and labor intensive. Moreover, there can be no assurance that such measures will be sufficient to prevent security breaches from occurring. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities.

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.
We may not achieve some or all of the expected benefits of the separation of CONSOL Energy, and failure to realize such benefits in a timely manner may materially adversely affect our business.
We may not be able to achieve the full strategic and financial benefits expected to result from the separation of our coal business, now operated by CONSOL Energy Inc., or such benefits may be delayed or not occur at all. The separation is expected to provide the following benefits, among others: (i) position management of each company to more effectively pursue its own focused, industry-specific strategy, creating additional operational flexibility and enabling our management team to focus on strengthening our core business, operations and other needs, and to pursue distinct and targeted opportunities for long-term growth and profitability; (ii) permit each company to efficiently allocate its capital to meet the unique needs of its own business, allowing each company to intensify its focus on its distinct business priorities and facilitate each business having a more appropriate capital aligned with its target capital levels and those of its peers, which is expected to increase access to capital; (iii) better position each company to recruit and retain executives and other employees with expertise more directly applicable to the needs of its business; allow each company more consistent application of incentive structures and targets, due to the common nature of the underlying businesses; clearer articulation of talent requirements for potential employees and understanding of the prerequisites and opportunities associated with each business; and (iv) improve understanding of each business in the capital markets and allow for a stronger, more focused investor base for each business; creation of two independent equity structures, enabling each business to use its own business-focused stock as consideration in acquisitions and equity compensation programs and creating a more efficient and valuable transaction currency and compensation tool. We may not achieve these and other anticipated benefits for a variety of reasons, including, among others: (i) we may be more susceptible to market fluctuations and other adverse events than if CONSOL Energy were still a part of the company because our business is less diversified than it was prior to the completion of the separation; and (ii) as a smaller, independent company, we may be more susceptible to fluctuations in the prices of natural gas, without having the coal business to mitigate such volatility. If we fail to achieve some or all of the benefits expected to result from the separation, or if such benefits are delayed, it could have a material adverse effect on our competitive position, business, financial condition, results of operations and cash flows.
CONSOL Energy may fail to perform under various transaction agreements that were executed as part of the separation.
In connection with the separation, CNX and CONSOL Energy entered into a Separation and Distribution Agreement and also entered into various other agreements, including a Transition Services Agreement, a Tax Matters Agreement, an Employee Matters Agreement, an Intellectual Property Matters Agreement, intellectual property license agreements, a real estate sublease, and Master Cooperation and Safety Agreements. The Separation and Distribution Agreement, the Tax Matters Agreement and the Employee Matters Agreement, together with the documents and agreements by which the internal reorganization of the Company prior to the separation was effected, determined the allocation of assets and liabilities between the companies following the separation for those respective areas and included any necessary indemnifications related to liabilities and obligations in connection therewith. The Transition Services Agreement provides for the performance of certain services by each company for the benefit of the other for a period of time after the separation. We will rely on CONSOL Energy to satisfy its performance and payment obligations under these agreements. If CONSOL Energy is unable or unwilling to satisfy its obligations under these agreements, including its indemnification obligations, we could incur operational difficulties and/or losses.

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 18–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

Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K is included in Exhibit 95 to this annual report.

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. The following table sets forth, for the periods indicated, the range of high and low sales prices per share of our common stock as reported on the New York Stock Exchange and the cash dividends declared on the common stock for the periods indicated:

	High	Low	Dividends
Year Period Ended December 31, 2017			
Quarter Ended March 31, 2017	$17.11	$12.77	$ —
Quarter Ended June 30, 2017	$15.16	$11.73	$ —
Quarter Ended September 30, 2017	$14.88	$12.03	$ —
Quarter Ended December 31, 2017	$16.11	$13.00	$ —
Year Period Ended December 31, 2016			
Quarter Ended March 31, 2016	$10.75	$3.93	$ 0.0100
Quarter Ended June 30, 2016	$14.20	$9.12	$ —
Quarter Ended September 30, 2016	$17.11	$13.01	$ —
Quarter Ended December 31, 2016	$19.34	$13.97	$ —

As of December 31, 2017, there were 120 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 peer group has changed from last year as a result of the spin-off of the coal business (See Note 2 - Discontinued Operations in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information). 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, 2012. The graph also assumes that all dividends were reinvested and that the investments were held through December 31, 2017.

	2012	2013	2014	2015	2016	2017
CNX Resources Corporation	100.0	119.9	107.4	25.7	59.3	55.0
Peer Group	100.0	129.1	88.3	38.8	53.1	40.4
S&P 500 Stock Index	100.0	129.6	144.4	143.4	157.0	187.4
Previous Peer Group	100.0	116.4	105.1	44.8	65.9	119.0

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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 CNXs Board of Directors, and no assurance can be given that CNX will pay dividends in the future. CNX suspended its quarterly dividend following the sale of the Buchanan Mine on March 31, 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 the then cumulative credit calculation. The total leverage ratio was 4.08 to 1.00 and the cumulative credit was approximately $389 million at December 31, 2017. The credit facility does not permit dividend payments in the event of default. The indentures to the 2022 and 2023 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, 2017.
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, 2017, 2016, 2015, 2014 and 2013 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, 2017 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,				
	2017	2016	2015	2014	2013
Revenue and Other Operating Income from Continuing Operations	$1,455,131	$759,968	$1,198,737	$1,080,351	$730,917
Income (Loss) from Continuing Operations	$295,039	$(550,945)	$(650,198)	$(269,625)	$(442,539)
Net Income (Loss)	$380,747	$(848,102)	$(374,885)	$163,090	$660,442
Earnings per share:					
Basic:					
Income (Loss) from Continuing Operations	$1.29	$(2.40)	$(2.84)	$(1.17)	$(1.93)
Income (Loss) from Discontinued Operations	0.37	(1.30)	1.20	1.88	4.82
Net Income (Loss)	$1.66	$(3.70)	$(1.64)	$0.71	$2.89
Dilutive:					
Income (Loss) from Continuing Operations	$1.28	$(2.40)	$(2.84)	$(1.17)	$(1.92)
Income (Loss) from Discontinued Operations	0.37	(1.30)	1.20	1.87	4.79
Net Income (Loss)	$1.65	$(3.70)	$(1.64)	$0.70	$2.87
Assets from Continuing Operations	$6,931,913	$6,682,770	$7,302,119	$7,968,069	$7,991,623
Assets from Discontinued Operations	—	2,496,921	3,627,783	3,686,576	3,156,312
Total Assets	$6,931,913	$9,179,691	$10,929,902	$11,654,645	$11,147,935
Long-Term Debt from Continuing Operations (including current portion)	$2,214,484	$2,456,354	$2,460,633	$3,129,433	$3,030,165
Long-Term Debt from Discontinued Operations (including current portion)	—	317,715	294,222	120,128	110,420
Total Long-Term Debt (including current portion)	$2,214,484	$2,774,069	$2,754,855	$3,249,561	$3,140,585
Cash Dividends Declared Per Share of Common Stock	$—	$0.010	$0.145	$0.250	$0.375

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,				
	2017	2016	2015	2014	2013
Gas:					
Net sales volumes produced (in Bcfe)	407.2	394.4	328.7	235.7	172.4

Average sales price ($ per Mcfe) (A)	$2.66	$2.63	$2.81	$4.37	$4.30
Average cost ($ per Mcfe)	$2.23	$2.32	$2.62	$3.13	$3.42
Proved reserves (in Bcfe) (B)	7,582	6,252	5,643	6,828	5,731

(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

2017 Highlights

- Record total gas production of 407.2 Bcfe in 2017, 3.2% higher than 2016.
- Record Marcellus Shale production of 239.4 Bcfe in 2017, 12.7% higher than 2016.
- Increased proved reserves to 7.6 Tcfe, 20.6% higher than 2016.
- 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. CNX's shareholders received one share of CONSOL Energy common stock for every eight shares of CNX's common stock held as of the close of business on November 15, 2017, the record date for the separation and distribution. 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 Form 10-K to discontinued operations for all periods presented.
- Gas production costs continue to decline - for the year ended December 31, 2017, total gas production costs were $2.23 per Mcfe, a 3.9% decline from the prior year.
- Repurchased $103 million of common stock on the open market.

2018 Outlook:

- Our 2018 annual gas production is expected to increase to approximately 520-550 Bcfe.
- Our 2018 E&P capital investment is expected to be approximately $790-$880 million..

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 a 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 shared 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	85,708	(297,157)	382,865
Net Income (Loss)	$380,747	$(848,102)	$1,228,849

CNX's principal activity is to produce pipeline quality natural gas for sale primarily to gas wholesalers. The Company's reportable segments are Marcellus Shale, Utica Shale, Coalbed Methane, and Other Gas.

CNX had income 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 2017 was an unrealized gain on commodity derivative instruments of $248 million and a gain on sale of assets of $188 million. Included in 2016 was an unrealized loss on commodity derivative instruments of $386 million, partially offset by a gain on sale of assets of $14 million. See Note 3 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

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	)%

Natural gas, NGLs, and oil sales were $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 34.9% increase in the average gas sales price per Mcf without the impact of derivative instruments and the 3.2% increase in total sales volumes. Sales volumes, average sales price (including the effects of derivatives instruments), and average costs for all active operations were as follows:

	For the Years Ended December 31,			
	2017	2016	Variance	Percent Change
Sales Volumes (Bcfe)	407.2	394.4	12.8	3.2 %
Average Sales Price (per Mcfe)	$2.66	$2.63	$ 0.03	1.1 %
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 a $0.67 per Mcf increase in general natural gas market prices in the Appalachian basin during the current period, as well as an overall increase in natural gas liquids pricing. The increase was offset, in part, by a $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 7 - 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 in the period-to-period comparison 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.

Certain costs and expenses such as selling, general and administrative, other expense, gain on sale of assets, loss on debt extinguishment, interest expense 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:

Selling, General and Administrative

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 include 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 benefits costs in the current year related to a reduction in headcount as well as a decrease in equity-based compensation expense.

Other Expense

(in millions)	For the Years Ended December 31, 2017	2016	Variance	Percent Change
Other Income				
Royalty Income	$10	$10	$ —	— %
Right of Way Sales	2	15	(13)	(86.7)%
Interest Income	9	—	9	100.0 %
Other	6	4	2	50.0 %
Total Other Income	$27	$29	$ (2)	(6.9)%
Other Expense				
Bank Fees	$13	$13	$ —	— %
Other Corporate Expense	12	16	(4)	(25.0)%
Other Land Rental Expense	6	5	1	20.0 %
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 the sale of approximately 35,900 net undeveloped acres in Ohio, Pennsylvania, and West Virginia in the current period. No individually significant transactions occurred in the year ended December 31, 2016. See Note 3 - 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 redemption of the 8.25% senior notes due in April 2020, the redemption of 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. See Note 10 - Long Term Debt in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

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 the 2020 and 2021 senior notes and the payoff of a portion of the 2022 senior notes during the year ended December 31, 2017.

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, 2017, CNX recognized favorable benefits of $279 million related to the impacts of income tax reform.

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 against state deferred tax assets and federal charitable contribution 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 current 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. At December 31, 2017, the Company has not finalized its accounting for the tax effects of the Act. However, as described in Note 5 - Income Taxes in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K, CNX has made a reasonable estimate of the tax effects of the Act, including the impact on existing deferred tax balances. The Company is still analyzing certain aspects of the Act, which could potentially affect the measurement of the Company's income tax balances.

See Note 5 - 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)%	

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TOTAL OPERATING SEGMENT ANALYSIS for the year ended December 31, 2017 compared to the year ended December 31, 2016:

CNX operating segments had earnings before income tax of $191 million for the year ended December 31, 2017 compared to a loss before income tax of $308 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 Sales	$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 Sales	—	—	—	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
Total Operating Costs and Expenses	525	153	179	407	1,264	35	(11)	(10)	182	196
Earnings (Loss) Before Income Tax	$91	$65	$20	$ 15	$191	$19	$37	$(18)	$461	$499

MARCELLUS SEGMENT

The Marcellus segment had earnings before income tax of $91 million for the year ended December 31, 2017 compared to earnings 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 sales of $646 million for the year ended December 31, 2017 compared to $415 million for the year ended December 31, 2016. The $231 million increase is 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 7 - 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 current 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 primarily 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 current 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 20 - 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 before income tax of $65 million for the year ended December 31, 2017 compared to earnings 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 sales 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 investments.

The increase in the total average Utica sales price was primarily due to the $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 the current period. The notional amounts associated with these financial hedges represented 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 are 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 costs 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 due 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 before income tax of $20 million for the year ended December 31, 2017 compared to earnings 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 the 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 earnings before income tax of $15 million for the year ended December 31, 2017 compared to a loss before income tax of $446 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. Natural gas, NGLs and oil sales 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 sales 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 the current period as well as the sale of Knox Energy in the second quarter of 2017 (See Note 3 - 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 represents 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 sales revenues were $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 sales revenue was primarily due to the increase in 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 the year 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 the prior year.

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 in costs is primarily related to the following items:

	For the Years Ended December 31,			
(in millions)	2017	2016	Variance	Percent Change
Lease Expiration Costs	$40	$ 7	$ 33	471.4 %
Land Rentals	4	4	—	— %
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 will expire within the next 12 months, because they were no longer in the Company's future drilling plan. Additionally, approximately $10 million of the $33 million increase is 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,			
	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.

Results of Operations: Year Ended December 31, 2016 Compared with the Year Ended December 31, 2015

Net Loss

CNX reported a net loss of $848 million, or a loss per diluted share of $3.70, for the year ended December 31, 2016, compared to a net loss of $375 million, or a loss of $1.64 per diluted share, for the year ended December 31, 2015.

	For the Years Ended December 31,		
(Dollars in thousands)	2016	2015	Variance
Loss from Continuing Operations	$(550,945)	$(650,198)	$99,253
(Loss) Income from Discontinued Operations, net	(297,157)	275,313	(572,470)
Net Loss	$(848,102)	$(374,885)	$(473,217)

CNX's principal activity is to produce pipeline quality natural gas for sale primarily to gas wholesalers. The Company's reportable segments are Marcellus Shale, Utica Shale, Coalbed Methane, and Other Gas.

CNX had a loss from continuing operations before income tax of $585 million for the year ended December 31, 2016, compared to a loss from continuing operations before income tax of $931 million for the year ended December 31, 2015. Included in the 2016 net loss before income tax was an unrealized loss on commodity derivative instruments of $386 million and a gain on sale of assets of $14 million. Included in the 2015 loss before income tax was a loss of $829 million primarily related to the impairment of the carrying value of CNX's shallow oil and natural gas assets due to depressed NYMEX forward strip prices (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). The impairment loss was partially offset by an unrealized gain on commodity derivative instruments of $197 million and a gain on sale of assets of $61 million. See Note 3 - Acquisitions and Dispositions in the Notes to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

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)	2016	2015	Variance	Percent Change
LIQUIDS				
NGLs:				
Sales Volume (MMcfe)	40,260	33,180	7,080	21.3 %
Sales Volume (Mbbls)	6,710	5,530	1,180	21.3 %
Gross Price ($/Bbl)	$14.52	$12.30	$2.22	18.0 %
Gross Revenue	$97,580	$68,057	$29,523	43.4 %
Oil:				
Sales Volume (MMcfe)	410	592	(182)	(30.7)%
Sales Volume (Mbbls)	68	99	(31)	(31.3)%
Gross Price ($/Bbl)	$36.90	$47.94	$(11.04)	(23.0)%
Gross Revenue	$2,521	$4,736	$(2,215)	(46.8)%
Condensate:				
Sales Volume (MMcfe)	4,964	7,598	(2,634)	(34.7)%
Sales Volume (Mbbls)	827	1,266	(439)	(34.7)%
Gross Price ($/Bbl)	$27.48	$26.52	$0.96	3.6 %
Gross Revenue	$22,748	$33,586	$(10,838)	(32.3)%
GAS				

Sales Volume (MMcf)	348,753	287,287	61,466	21.4 %
Sales Price ($/Mcf)	$1.92	$2.17	$(0.25)	(11.5)%
Gross Revenue	$670,823	$622,080	$48,743	7.8 %
Hedging Impact ($/Mcf)	$0.70	$0.68	$0.02	2.9 %
Gain on Commodity Derivative Instruments - Cash Settlement	$245,212	$196,348	$48,864	24.9 %

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Natural gas, NGLs, and oil sales were $793 million for the year ended December 31, 2016, compared to $727 million for the year ended December 31, 2015. The increase was primarily due to the 20.0% increase in total sales volumes, offset in part by the 11.5% decrease in the average gas sales price per Mcf without the impact of derivative instruments. The decrease in average sales price was the result of the overall decrease in general market prices.

Sales volumes, average sales price (including the effects of derivative instruments), and average costs for all active operations were as follows:

	For the Years Ended December 31,			
	2016	2015	Variance	Percent Change
Sales Volumes (Bcfe)	394.4	328.7	65.7	20.0 %
Average Sales Price (per Mcfe)	$2.63	$2.81	$(0.18)	(6.4)%
Average Costs (per Mcfe)	2.32	2.62	(0.30)	(11.5)%
Average Margin	$0.31	$0.19	$0.12	63.2 %

The decrease in average sales price was primarily the result of a $0.25 Mcf decrease in general market prices in the Appalachian basin during the current period, as well as an overall decrease in natural gas liquids pricing. The increase was offset, in part, by a $0.02 Mcf increase in the realized 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 7 - 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 in the period-to-period comparison 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.
- Transportation, gathering, and compression expense decreased on a per unit basis in the period-to-period comparison due to the overall increase in sales volumes, the shift towards dry Utica Shale production which has lower gathering costs, and a decrease in pipeline and facility maintenance expense.

Certain costs and expenses such as selling, general and administrative, other expense, gain on sale of assets, loss on debt extinguishment, interest expense 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:

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.