Table of Contents
Index to Financial Statements

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

Form 10-K

☒ Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended **December 31, 2020**
Commission file number **001-08246**

Southwestern Energy Company

(Exact name of registrant as specified in its charter)

Delaware	**71-0205415**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

10000 Energy Drive
Spring, Texas 77389
(Address of principal executive offices)(Zip Code)
(832) 796-1000
(Registrant's telephone number, including area code)

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock, Par Value $0.01	SWN	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 ☒ No ☐

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

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 ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

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

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐ Emerging growth company ☐

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

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

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

The aggregate market value of the voting stock held by non-affiliates of the registrant was $1,493,259,580 based on the New York Stock Exchange – Composite Transactions closing price on June 30, 2020 of $2.56. For purposes of this calculation, the registrant has assumed that its directors and executive officers are affiliates.

As of February 25, 2021, the number of outstanding shares of the registrant's Common Stock, par value $0.01, was 674,457,398.

Document Incorporated by Reference

Portions of the registrant's definitive proxy statement to be filed with respect to the annual meeting of stockholders to be held on or about May 18, 2021 are incorporated by reference into Part III of this Form 10-K.

SOUTHWESTERN ENERGY COMPANY
ANNUAL REPORT ON FORM 10-K
For Fiscal Year Ended December 31, 2020

TABLE OF CONTENTS

This Annual Report on Form 10-K ("Annual Report") includes certain statements that may be deemed to be "forward-looking" within the meaning of Section 27A of the Securities Act of 1933, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, or the Exchange Act. We refer you to "Risk Factors" in Item 1A of Part I and to "Management's Discussion and Analysis of Financial Condition and Results of Operations – Cautionary Statement about Forward-Looking Statements" in Item 7 of Part II of this Annual Report for a discussion of factors that could cause actual results to differ materially from any such forward-looking statements. The electronic version of this Annual Report, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those forms filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act are available free of charge as soon as reasonably practicable after they are filed with the Securities and Exchange Commission, or SEC, on our website at www.swn.com. Our corporate governance guidelines and the charters of the Audit, the Compensation, the Health, Safety, Environment and Corporate Responsibility and the Nominating and Governance Committees of our Board of Directors are available on our website and, upon request, in print free of charge to any stockholder. Information on our website is not incorporated into this report.

We file periodic reports, current reports and proxy statements with the SEC electronically. The SEC maintains an internet website that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC. The address of the SEC's website is www.sec.gov. The public may also read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street N.E., Washington, D.C. 20549. The public may obtain information about the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330.

PART I

ITEM 1. BUSINESS

Southwestern Energy Company (including its subsidiaries, collectively, “we”, “our”, “us”, “the Company” or “Southwestern”) is an independent energy company engaged in exploration, development and production activities, including the related marketing of natural gas, oil and natural gas liquids (“NGLs”) produced in our operations. Southwestern is a holding company whose assets consist of direct and indirect ownership interests in, and whose business is conducted substantially through, its subsidiaries. Currently we operate exclusively in the United States. Our common stock is listed and traded on the NYSE under the ticker symbol “SWN.”

Southwestern, which is incorporated in Delaware, has its executive offices located at 10000 Energy Drive, Spring, Texas 77389, and can be reached by phone at 832-796-1000. The Company also maintains offices in Tunkhannock, Pennsylvania, Morgantown, West Virginia, and Zanesville, Ohio.

Our Business Strategy

We aim to deliver sustainable and industry-leading returns through excellence in exploration and production and marketing performance from our extensive resource base and targeted expansion of our activities and assets along the hydrocarbon value chain. Our Company’s formula embodies our corporate philosophy and guides how we operate our business:

$$\frac{R^2}{A} \rightsquigarrow V^{+}$$

Our formula, “The Right People doing the Right Things, wisely investing the cash flow from our underlying Assets will create Value+,” also guides our business strategy. We always strive to attract and retain strong talent, to work safely and act ethically with unwavering vigilance for the environment and the communities in which we operate, and to creatively apply technical skills, which we believe will grow long-term value for our shareholders. The arrow in our formula is not a straight line: we acknowledge that factors may adversely affect quarter-by-quarter results, but the path over time points to value creation.

In applying these core principles, we concentrate on:

- ***Financial Strength.*** We are committed to rigorously managing our balance sheet and financial risks. We budget and dynamically manage our operations in order to ensure that our investments do not exceed our cash flow from operations (net of changes in working capital) in each calendar year, protect our projected cash flows through hedging and continue to maintain a strong balance sheet with ample liquidity. Our capital investment program in 2020 was supplemented with the remaining earmarked proceeds from the sale of our Fayetteville Shale assets in December 2018.

- ***Increasing Margins.*** We apply strong technical, operational, commercial and marketing skills to reduce costs, improve the productivity of our wells and pursue commercial arrangements to extract greater value. We believe our demonstrated ability to maximize margins, especially by leveraging the scale of our large assets, gives us a competitive advantage as we move into the future.

- ***Exercising Capital Allocation Discipline***. We continually assess market conditions in order to adjust our capital allocation decisions to maximize shareholder returns. This allocation process includes consideration of multiple alternatives including but not limited to the development of our natural gas and oil assets, strategic mergers or acquisitions, reducing debt and returning capital to our shareholders.

- ***Operational Value Creation***. We prepare an economic analysis for our drilling programs and other investments based upon the expected Internal Rate of Return. We target projects that generate the highest returns in excess of our cost of capital. This disciplined investment approach governs our investment decisions at all times, including the current lower-price commodity market.

- ***Dynamic Management of Assets Throughout Life Cycle***. We own large-scale, long-life assets in various phases of development. In early stages, we ramp up development through technical, operational and commercial skills, and as they grow we look for ways to maximize their value through efficient operating practices along with applying our commercial and marketing expertise.

- ***Deepening Our Inventory***. We continue to expand the inventory of properties that we can develop profitably by converting our extensive resources into proved reserves, targeting additions whose productivity largely has been demonstrated and improving efficiencies in production.

- ***The Hydrocarbon Value Chain.*** We believe that our vertical integration enhances our margins and provides us competitive advantages. For example, we own and operate drilling rigs and well stimulation equipment and have invested in a water transportation project in West Virginia. These activities provide operational flexibility, lower our well costs, minimize the risk associated with the lack of availability of these resources from third parties and capture additional value over time.
- ***Technological Innovation.*** Our people constantly search for the next revolutionary technology and other operational advancements to capture greater value in unconventional hydrocarbon resource development. These developments – whether single, step-changing technologies or a combination of several incremental ones – can reduce finding and development costs and thus increase our margins.
- ***Environmental Solutions and Policy Formation.*** We are a leader in identifying and implementing innovative solutions to unconventional hydrocarbon development to minimize the environmental and community impacts of our activities. We work extensively with governmental, non-governmental and industry stakeholders to develop responsible and cost-effective programs. We demonstrate that a company can operate responsibly and profitably, putting us in a better position to comply with new regulations as they evolve.

During 2020 we executed on these business strategies by:

- Expanding our portfolio in Appalachia by acquiring Montage Resources Corporation through an accretive all-stock transaction, increasing our economic inventory while recognizing immediate cost structure savings;
- Dynamically managing our operational focus from liquids to dry gas in response to adverse economic conditions, resulting from the COVID-19 pandemic, in order to take advantage of more favorable commodity pricing;
- Lowering our costs through drilling, completions and operational efficiencies and optimizing gathering and transportation costs;
- Continuing to identify and implement structural, process and organizational changes to further reduce general and administrative costs;
- Maintaining a robust multi-year hedging program to ensure a certain level of cash flow;
- Focusing on delivering operational excellence with improved well productivity and economics from enhanced completion techniques, innovative water sourcing, optimization of surface equipment and managing reservoir drawdown;
- Repurchasing approximately $107 million in aggregate principal amount of our outstanding senior notes for $72 million, recognizing a gain on the extinguishment of debt of $35 million; and
- Publishing our 7th Annual Corporate Responsibility report for 2019 (available at www.swn.com). Key environmental highlights include:
    - We reported the lowest greenhouse gas intensity among our Appalachian peers in the annual Environmental Health and Safety Survey;
    - Our methane intensity was 85% better than the target set by ONE Future (a coalition of 37 natural gas companies working together to voluntarily lower methane emissions); and
    - We were fresh water neutral for the fifth year in a row; 100% of our fresh water usage was offset through recycling and conservation projects.

Note that the information on our website is not incorporated by reference into this filing.

The bulk of our operations, which we refer to as “Exploration and Production” (“E&P”), are focused on the finding and development of natural gas, oil and NGL reserves. We are also focused on creating and capturing additional value through our marketing business, which we refer to as “Marketing.”

Exploration and Production

Overview

Our primary business is the exploration for, and production of, natural gas, oil and NGLs, with our current operations solely within the United States. We are currently focused on the development of unconventional natural gas reservoirs located in Pennsylvania, Ohio and West Virginia. Our operations in northeast Pennsylvania (herein referred to as “Northeast Appalachia”) are primarily focused on the unconventional natural gas reservoir known as the Marcellus Shale, and our operations in West Virginia, southwest Pennsylvania and Ohio (herein referred to as “Southwest Appalachia”) are focused on the Marcellus Shale, the Utica and the Upper Devonian unconventional natural gas, oil and NGL reservoirs. Collectively, our properties located in Pennsylvania, Ohio and West Virginia are herein referred to as “Appalachia.”

- Our E&P segment recorded operating loss of $2,864 million in 2020, compared to operating income of $283 million in 2019. Our E&P segment operating income (loss) decreased $3,147 million in 2020 from 2019 primarily due to $2,825 million of non-cash full cost ceiling test impairments. Excluding the impact of ceiling test impairments, operating income (loss) decreased $322 million compared to the same period in 2019 primarily due to lower margins associated with decreased commodity pricing.
- Our cash flow from operations was $372 million in 2020, compared to $781 million in 2019. This $409 million decrease was primarily due to a 20% decrease in weighted average commodity prices, including derivatives, partially offset by a 13% increase in production volumes.

Oilfield Services Vertical Integration

We provide certain oilfield services that are strategic and economically beneficial for our E&P operations when our E&P activity levels and market pricing support these activities. This vertical integration lowers our well costs, allows us to operate efficiently, provides agility to our operations allowing us to react quickly to rapid changes in market conditions and helps us to mitigate certain operational and environmental risks. These services include drilling, completions and water management and movement. As of December 31, 2020, we operated a fleet of drilling rigs and leased two pressure pumping spreads with a total capacity of 72,000 horsepower. These assets provide us greater flexibility to align our operational activities with commodity prices. In 2020, we provided drilling rigs for all of our 98 drilled wells. In addition, we provided completions services utilizing one pressure pumping spread in Southwest Appalachia.

Our Proved Reserves

	For the years ended December 31,	
	2020	2019
Proved reserves: *(Bcfe)*		
Appalachia	11,989	12,720
Other	1	1
Total proved reserves	11,990	12,721
Prices used:		
Natural gas *(per Mcf)*	$ 1.98	$ 2.58
Oil *(per Bbl)*	$ 39.57	$ 55.69
NGL *(per Bbl)*	$ 10.27	$ 11.58
PV-10: *(in millions)*		
Pre-tax	$ 1,847	$ 3,735
PV of taxes	— (1)	(35)
After-tax	$ 1,847	$ 3,700
Percent of estimated proved reserves that are:		
Natural gas	76 %	68 %
Proved developed	68 %	50 %
Percent of E&P operating revenues generated by natural gas sales	69 %	71 %

(1) Our existing tax attributes, including net operating losses and remaining depreciable tax basis related to our natural gas and oil properties, more than offset our future net operating income, resulting in no tax effect to our PV-10 calculation for the year ended December 31, 2020.

Our reserve estimates and the after-tax PV-10 measure, or standardized measure of discounted future net cash flows relating to proved natural gas, oil and NGL reserve quantities, are highly dependent upon the respective commodity price used in our reserve and after-tax PV-10 calculations.

- Our reserves decreased 6% in 2020, compared to 2019, primarily due to a decrease in commodity pricing, partially offset by the reserves acquired from Montage.
- Our after-tax PV-10 value decreased in 2020 compared to 2019 as lower reserve levels resulted primarily from a decrease in SEC 12-month backward-looking commodity prices.
- We are the designated operator of approximately 97% of our reserves, based on the pre-tax PV-10 value of our proved developed producing reserves, and our reserve life index was approximately 11.3 years at year-end 2020, using an estimate of full year production from our recently acquired Montage properties.

The following table presents the PV-10 value of our reported year-end 2020 reserves balance using SEC 12-month backward-looking prices and the 12-month forward-looking strip prices as of January 4, 2021:

	2020 Year-End	
	SEC Pricing (1)	Strip Pricing
Natural gas price *(per MMBtu)*	$ 1.98	$ 2.70
WTI oil price *(per Bbl)*	$ 39.57	$ 47.67
NGL price *(per Bbl)*	$ 10.27	$ 11.82
Proved reserves after-tax PV-10 *(in billions)*	$ 1.85	$ 5.85

(1) Adjusted for market differentials.

The difference in after-tax PV-10 and pre-tax PV-10 (a non-GAAP measure which is reconciled in the 2020 Proved Reserves by Category and Summary Operating Data table below) is the discounted value of future income taxes on the estimated cash flows. Our existing tax attributes, including net operating losses and remaining depreciable tax basis related to our natural gas and oil properties, more than offset our future net operating income, resulting in no tax effect to our PV-10 calculation for the year ended December 31, 2020.

We believe that the pre-tax PV-10 value of the estimated cash flows related to our estimated proved reserves is a useful supplemental disclosure to the after-tax PV-10 value. Pre-tax PV-10 is based on prices, costs and discount factors that are comparable from company to company, while the after-tax PV-10 is dependent on the unique tax situation of each individual company. We understand that securities analysts use pre-tax PV-10 as one measure of the value of a company's current proved reserves and to compare relative values among peer companies without regard to income taxes. We refer you to "Supplemental Oil and Gas Disclosures" in Item 8 of Part II of this Annual Report for a discussion of our standardized measure of discounted future cash flows related to our proved natural gas, oil and NGL reserves, to the risk factor "Our proved natural gas, oil and NGL reserves are estimates that include uncertainties. Any material change to these uncertainties or underlying assumptions could cause the quantities and net present value of our reserves to be overstated or understated" in Item 1A of Part I of this Annual Report, and to "Management's Discussion and Analysis of Financial Condition and Results of Operations – Cautionary Statement about Forward-Looking Statements" in Item 7 of Part II of this Annual Report for a discussion of the risks inherent in utilization of standardized measures and estimated reserve data.

Lower natural gas, oil and NGL prices reduce the value of our assets, both by a direct reduction in what the production could be sold for and by making some properties uneconomic, resulting in decreases to the overall value of our reserves and potential non-cash impairment charges to earnings. Further non-cash impairments in future periods could occur if the trailing 12-month commodity prices decrease as compared to the average used in prior periods.

The following table provides an overall and categorical summary of our natural gas, oil and NGL reserves, as of year-end 2020 based on average year prices, and our well count, net acreage and PV-10 as of December 31, 2020, and sets forth 2020 annual information related to production and capital investments for each of our operating areas:

2020 PROVED RESERVES BY CATEGORY AND SUMMARY OPERATING DATA

	Appalachia			
	Northeast	**Southwest**	**Other** [1]	**Total**
Estimated proved reserves:				
Natural gas *(Bcf)*:				
Developed	3,668	2,674	—	**6,342**
Undeveloped	1,248	1,591	—	**2,839**
	4,916	4,265	—	**9,181**
Crude oil *(MMBbls)*:				
Developed	—	33.5	0.1	**33.6**
Undeveloped	—	24.5	—	**24.5**
	—	58.0	0.1	**58.1**
Natural gas liquids *(MMBbls)*:				
Developed	—	276.5	—	**276.5**
Undeveloped	—	133.6	—	**133.6**
	—	410.1	—	**410.1**
Total proved reserves *(Bcfe)* [2]:				
Developed	3,668	4,534	1	**8,203**
Undeveloped	1,248	2,539	—	**3,787**
	4,916	7,073	1	**11,990**
Percent of total	41%	59%	—%	**100%**
Percent proved developed	75%	64%	100%	**68%**
Percent proved undeveloped	25%	36%	0%	**32%**
Production *(Bcfe)*	473	407	—	**880**
Capital investments *(in millions)*	$ 362	$ 510	$ 27 [3]	**$ 899**
Total gross producing wells [4]	744	1,833	14	**2,591**
Total net producing wells	668	1,521	11	**2,200**
Total net acreage	217,296	571,922	22,001 [5]	**811,219**
Net undeveloped acreage	89,086	425,702	9,764 [5]	**524,552**
PV-10:				
Pre-tax *(in millions)* [6]	$ 876	$ 974	$ (3) [7]	**$ 1,847**
PV of taxes *(in millions)* [6]	—	—	—	**—**
After-tax *(in millions)* [6]	$ 876	$ 974	$ (3) [7]	**$ 1,847**
Percent of total	47%	53%	0%	**100%**
Percent operated [8]	98%	100%	97%	**97%**

(1) Other reserves and acreage consists primarily of properties in Colorado.

(2) We have no reserves from synthetic gas, synthetic oil or nonrenewable natural resources intended to be upgraded into synthetic gas or oil. We used standard engineering and geoscience methods, or a combination of methodologies in determining estimates of material properties, including performance and test date analysis, offset statistical analogy of performance data, volumetric evaluation, including analysis of petrophysical parameters (including porosity, net pay, fluid saturations (i.e., water, oil and gas) and permeability) in combination with estimated reservoir parameters (including reservoir temperature and pressure, formation depth and formation volume factors), geological analysis, including structure and isopach maps and seismic analysis, including review of 2-D and 3-D data to ascertain faults, closure and other factors.

(3) Other capital investments includes $9 million related to our water infrastructure project, $16 million related to our E&P service companies and $2 million related to other developmental activities.

(4) Excludes 587 wells in Northeast Appalachia and 99 wells in Southwest Appalachia in which we only have an overriding royalty interest. These wells were included in the December 31, 2020 reserves calculation.

(5) Excludes exploration licenses for 2,518,519 net acres in New Brunswick, Canada, which have been subject to a moratorium since 2015. We are currently working with Canadian officials to extend our licenses, although we cannot assure that the licenses will be extended past March 2021.

(6) Pre-tax PV-10 (a non-GAAP measure) is one measure of the value of a company's proved reserves that we believe is used by securities analysts to compare relative values among peer companies without regard to income taxes. The reconciling difference in pre-tax PV-10 and the after-tax PV-10, or standardized measure, is the discounted value of future income taxes on the estimated cash flows from our proved natural gas, oil and NGL reserves. Our existing tax attributes, including net operating losses and remaining depreciable tax basis related to our natural gas and oil properties, more than offset our future net operating income, resulting in no tax effect to our PV-10 calculation for the year ended December 31, 2020.

(7) Includes future asset retirement obligations outside of Appalachia.

(8) Based upon pre-tax PV-10 of proved developed producing activities.

Lease Expirations

The following table summarizes the leasehold acreage expiring over the next three years, assuming successful wells are not drilled to develop the acreage and leases are not extended:

	For the years ended December 31,		
Net acreage expiring:	2021	2022	2023
Northeast Appalachia	5,861 (1)	6,460	6,921
Southwest Appalachia (2)	36,690 (1)	20,149	11,986
Other			
US – Other Exploration	5,683	646	—
US – Sand Wash Basin	3,435	—	—
Canada – New Brunswick (3)	2,518,519	—	—

(1) We have no reported proved undeveloped locations expiring in 2021.

(2) The leasehold acreage expiring includes 8,907 acres acquired through the Montage Merger that are subject to annual extension options at our sole discretion. Excluding this acreage, of the remaining leasehold acreage expiring, 17,460 net acres in 2021, 6,173 net acres in 2022 and 5,573 net acres in 2023 can be extended for an average 4.9 years.

(3) Exploration licenses were extended through March 2021 but have been subject to a moratorium since 2015. We are currently working with Canadian officials to extend our licenses, although we cannot assure that the licenses will be extended past March 2021. We fully impaired our investment in New Brunswick in 2016.

We refer you to "Supplemental Oil and Gas Disclosures" in Item 8 of Part II of this Annual Report for a more detailed discussion of our proved natural gas, oil and NGL reserves as well as our standardized measure of discounted future net cash flows related to our proved natural gas, oil and NGL reserves. We also refer you to the risk factor "Our proved natural gas, oil and NGL reserves are estimates that include uncertainties. Any material changes to these uncertainties or underlying assumptions could cause the quantities and net present value of our reserves to be overstated or understated" in Item 1A of Part I of this Annual Report and to "Management's Discussion and Analysis of Financial Condition and Results of Operations – Cautionary Statement about Forward-Looking Statements" in Item 7 of Part II of this Annual Report for a discussion of the risks inherent in utilization of standardized measures and estimated reserve data.

Proved Undeveloped Reserves

Presented below is a summary of changes in our proved undeveloped reserves for 2019 and 2020:

CHANGES IN PROVED UNDEVELOPED RESERVES

	Appalachia		
(in Bcfe)	**Northeast**	**Southwest**	**Total**
December 31, 2018	**1,039**	**5,325**	**6,364**
Extensions, discoveries and other additions	677	327	**1,004**
Performance and production revisions (1)	(40)	723	**683**
Reclassification of PUD to unproved under SEC five-year rule (2)	—	(109)	**(109)**
Price revisions	(12)	(395)	**(407)**
Developed	(397)	(838)	**(1,235)**
Disposition of reserves in place	—	—	**—**
Acquisition of reserves in place	—	—	**—**
December 31, 2019	**1,267**	**5,033**	**6,300**
Extensions, discoveries and other additions	474	—	**474**
Performance and production revisions (1)	(26)	593	**567**
Price revisions	(213)	(3,075)	**(3,288)**
Developed	(457)	(1,030)	**(1,487)**
Disposition of reserves in place	—	—	**—**
Acquisition of reserves in place	203	1,018	**1,221**
December 31, 2020	**1,248**	**2,539**	**3,787**

(1) Primarily due to changes associated with the analysis of updated data collected in the year and decreases related to current year production.

(2) Consists of reserves associated with planned wells that were PUD at the beginning of the year but were subsequently reclassified to unproved due to changes in the drilling plan, in accordance with the SEC five-year rule.

Performance, production and price revisions consist of revisions to reserves associated with wells having proved reserves in existence as of the beginning of the year. Extensions, discoveries and other additions include new reserves locations added in the current year.

- As of December 31, 2020, we had 3,787 Bcfe of proved undeveloped reserves, all of which we expect will be developed within five years of the initial disclosure as the starting reference date. During 2020, we invested $674 million in connection with converting 1,487 Bcfe, or 24%, of our proved undeveloped reserves as of December 31, 2019 into proved developed reserves and added 474 Bcfe of proved undeveloped reserves. As a result of the commodity price environment in 2020, we had downward price revisions of 3,288 Bcfe. These reductions were partially offset by a 567 Bcfe increase due to performance and production revisions.

- As of December 31, 2019, we had 6,300 Bcfe of proved undeveloped reserves. During 2019, we invested $638 million in connection with converting 1,235 Bcfe, or 19%, of our proved undeveloped reserves as of December 31, 2018 into proved developed reserves and added 1,004 Bcfe of proved undeveloped reserves. As a result of the commodity price environment in 2019, we had downward price revisions of 407 Bcfe. In addition, we also had 109 Bcfe that was reclassified to unproven. These reductions were more than offset by a 683 Bcfe increase due to performance and production revisions. Certain planned wells that were proved undeveloped as of the beginning of 2019 were rescheduled beyond five years. Accordingly, the proved undeveloped reserves associated with these planned wells were removed in 2019 as they fell outside of the SEC mandated five-year development window. We expect these previous proved undeveloped reserves to be added back in future years.

Our December 31, 2020 proved reserves included 2,437 Bcfe of proved undeveloped reserves from 138 locations that have a positive present value on an undiscounted basis in compliance with proved reserve requirements but do not have a positive present value when discounted at 10%. These properties have a negative present value of $207 million when discounted at 10%. We have made a final investment decision and are committed to developing these reserves within five years from the date of initial booking.

We expect that the development costs for our proved undeveloped reserves of 3,787 Bcfe as of December 31, 2020 will require us to invest an additional $1.6 billion for those reserves to be brought to production. Our ability to make the necessary investments to generate these cash inflows is subject to factors that may be beyond our control. The commodity price environment over the past year has resulted, and could continue to result, in certain reserves no longer being economic to produce, leading to both lower proved reserves and cash flows. We refer you to the risk factors "Natural gas, oil and NGL prices greatly affect our revenues and thus profits, liquidity, growth, ability to repay our debt and the value of our assets" and "Significant capital investment is required to replace our reserves and conduct our business" in Item 1A of Part I of this Annual Report and to "Management's Discussion and Analysis of Financial Condition and Results of Operations – Cautionary Statement about Forward-Looking Statements" in Item 7 of Part II of this Annual Report for a more detailed discussion of these factors and other risks.

Our Reserve Replacement

The reserve replacement ratio measures the success of an E&P company in adding new reserves to replace the reserves that are being depleted by its current production volumes. The reserve replacement ratio, which we discuss below, is an important analytical measure used by investors and peers in the E&P industry to evaluate performance results and long-term prospects. There are limitations as to the usefulness of this measure, as it does not reflect the type of reserves or the cost of adding the reserves or indicate the potential value of the reserve additions.

In 2020, we replaced 84% of our production volumes with 741 Bcfe of proved reserve additions, all of which were from Appalachia. The impact of the reserve decrease associated with price revisions was substantially offset by the positive performance and production revisions and reserves acquired in the Montage acquisition. The following table summarizes the changes in our proved natural gas, oil and NGL reserves for the year ended December 31, 2020:

	Appalachia			
(in Bcfe)	Northeast	Southwest	Other (1)	**Total**
December 31, 2019	**4,837**	**7,883**	**1**	**12,721**
Net revisions				
Price revisions	(389)	(3,981)	—	**(4,370)**
Performance and production revisions	46	1,378	—	**1,424**
Total net revisions	(343)	(2,603)	—	**(2,946)**
Extensions, discoveries and other additions				
Proved developed	198	69	—	**267**
Proved undeveloped	474	—	—	**474**
Total reserve additions	672	69	—	**741**
Production	(473)	(407)	—	**(880)**
Acquisition of reserves in place	223	2,131	—	**2,354**
Disposition of reserves in place	—	—	—	**—**
December 31, 2020	**4,916**	**7,073**	**1**	**11,990**

(1) Other includes properties outside of Appalachia.

Our ability to add reserves depends upon many factors that are beyond our control. We refer you to the risk factors "Significant capital investment is required to replace our reserves and conduct our business" and "If we are not able to replace reserves, our production levels and thus our revenues and profits may decline." in Item 1A of Part I of this Annual Report and to "Management's Discussion and Analysis of Financial Condition and Results of Operations – Cautionary Statement about Forward-Looking Statements" in Item 7 of Part II of this Annual Report for a more detailed discussion of these factors and other risks.

Our Operations

Northeast Appalachia

Northeast Appalachia represented 54% of our total 2020 net production and 41% of our total reserves as of December 31, 2020. In 2020, our reserves in Northeast Appalachia increased by 79 Bcf, which included net additions of 672 Bcf, acquisitions of 223 Bcf and net upward performance revisions of 46 Bcf, partially offset by net downward price revisions of 389 Bcf and production of 473 Bcf. As of December 31, 2020, we had approximately 217,296 net acres in Northeast Appalachia and had a total of 677 wells on production that we operated. Below is a summary of Northeast Appalachia's operating results for the latest two years:

	For the years ended December 31,	
	2020	2019
Acreage		
Net undeveloped acres	89,086 (1)	53,435
Net developed acres	128,210	120,559
Total net acres	217,296	173,994
Net Production *(Bcf)*	473	459
Reserves		
Reserves *(Bcf)*	4,916	4,837
Locations:		
Proved developed producing (2)	744	695
Proved developed non-producing (3)	9	11
Proved undeveloped	57	82
Total locations	810	788
Gross Operated Well Count Summary		
Drilled	49	39
Completed	44	44
Wells to sales	45	44
Capital Investments *(in millions)*		
Drilling and completions, including workovers	$ 321	$ 314
Acquisition and leasehold	9	13
Seismic and other	9	5
Capitalized interest and expense	23	33
Total capital investments	$ 362	$ 365
Average completed well cost *(in millions)*	$ 6.8	$ 7.3
Average lateral length *(feet)*	10,765	9,029

(1) Our undeveloped acreage position as of December 31, 2020 had an average royalty interest of 15%.

(2) Excludes 587 and 516 wells as of December 31, 2020 and 2019, respectively, in which we have only an overriding royalty interest.

(3) Excludes 27 and 3 wells as of December 31, 2020 and 2019, respectively, in which we have only an overriding royalty interest.

For 2020 as compared to 2019:

- Our average completed well cost per foot decreased primarily due to increased lateral lengths and operational execution.

Our ability to bring our Northeast Appalachia production to market depends on a number of factors including the construction of and/or the availability of capacity on gathering systems and pipelines that we do not own. We refer you to "Marketing" in Item 1 of Part I of this Annual Report for a discussion of our gathering and transportation arrangements for Northeast Appalachia production.

Southwest Appalachia

Southwest Appalachia represented 46% of our total 2020 net production and 59% of our total reserves as of December 31, 2020. In 2020, our reserves in Southwest Appalachia decreased by 810 Bcfe, as net downward price revisions of 3,981 Bcfe and production of 407 Bcfe were only partially offset by acquisitions of 2,131 Bcfe, net upward performance revisions of 1,378 Bcfe and net additions of 69 Bcfe. As of December 31, 2020, we had approximately 571,922 net acres in Southwest Appalachia and had a total of 1,670 wells on production that we operated. Below is a summary of Southwest Appalachia's operating results for the latest two years:

	For the years ended December 31, 2020	2019
Acreage		
Net undeveloped acres	425,702 [1]	205,222
Net developed acres	146,220	82,471
Total net acres	571,922	287,693
Net Production		
Natural gas *(Bcf)*	221	150
Oil *(MBbls)*	5,124	4,673
NGL *(MBbls)*	25,923	23,611
Total production *(Bcfe)* [2]	407	319
Reserves		
Reserves *(Bcfe)*	7,073	7,883
Locations:		
Proved developed producing [3]	1,833	496
Proved developed non-producing [4]	162	48
Proved undeveloped	151	376
Total locations	2,146	920
Gross Operated Well Count Summary		
Drilled	49	66
Completed	52	72
Wells to sales	55	69
Capital Investments *(in millions)*		
Drilling and completions, including workovers	$ 360	$ 516
Acquisition and leasehold	28	42
Seismic and other	1	3
Capitalized interest and expense	121	149
Total capital investments [5]	$ 510	$ 710
Average completed well cost *(in millions)* [6]	$ 9.3	$ 8.9
Average lateral length *(feet)* [6]	13,265	10,642

(1) Our undeveloped acreage position as of December 31, 2020 had an average royalty interest of 15%.

(2) Approximately 405 Bcfe and 317 Bcfe for the years ended December 31, 2020 and 2019, respectively, were produced from the Marcellus Shale formation.

(3) Excludes 99 and 5 wells as of December 31, 2020 and 2019, respectively, in which we have only an overriding royalty interest.

(4) Excludes 27 wells as of December 31, 2020 in which we have only an overriding royalty interest.

(5) Excludes $9 million and $35 million for the years ended December 31, 2020 and 2019, respectively, related to our water infrastructure project.

(6) Average completed well cost and average lateral length for the years ended December 31, 2020 and 2019 include both Marcellus wells and Upper Devonian wells.

For 2020 as compared to 2019:

- Our average completed well cost per foot decreased primarily due to increased lateral lengths, operational execution and savings from vertical integration.

Our ability to bring our Southwest Appalachia production to market will depend on a number of factors including the construction of and/or the availability of capacity on gathering systems and pipelines that we do not own. We refer you to "Marketing" within Item 1 of Part I of this Annual Report for a discussion of our gathering and transportation arrangements for Southwest Appalachia production.

Other

Excluding 2,518,519 acres in New Brunswick, Canada, which have been subject to a government-imposed drilling moratorium since 2015, we held 9,764 net undeveloped acres for the potential development of new resources as of December 31, 2020 in areas outside of Appalachia. This compares to 27,334 net undeveloped acres held at year-end 2019, excluding the New Brunswick acreage.

We limited our activities in areas beyond our assets in Appalachia during 2020 and 2019 as a result of the commodity price environment as we focused our capital allocation on these more economically competitive plays. There can be no assurance that any prospects outside of our development plays will result in viable projects or that we will not abandon our initial investments.

New Brunswick, Canada. We currently hold exclusive licenses to search and conduct an exploration program covering 2,518,519 net acres in New Brunswick. In 2015, the provincial government in New Brunswick imposed a moratorium on hydraulic fracturing until it is satisfied with a list of conditions. In response to this moratorium, we requested and were granted an extension of its licenses to March 2021. In May 2016, the provincial government announced that the moratorium would continue indefinitely. Given this development, we fully impaired our investment in New Brunswick in 2016. We are currently working with Canadian officials to extend our licenses, although we cannot assure that the licenses will be extended past March 2021. Unless and until the moratorium is lifted, we will not be able to develop these assets.

Acquisitions and Divestitures

In November 2020, we completed a merger with Montage Resources Corporation (the "Merger") pursuant to which Montage merged with and into Southwestern, with Southwestern continuing as the surviving company. At the effective time of the Merger we acquired all of the outstanding shares of common stock in Montage in exchange for 1.8656 shares of our common stock per share of Montage common stock. The Merger expanded our footprint in Appalachia by supplementing our Northeast Appalachia and Southwest Appalachia operations and by expanding our operations into Ohio. See Note 3 to the consolidated financial statements of this Annual Report for more information on the Merger.

During 2019, we sold non-core acreage for $38 million. There was no production or proved reserves associated with this acreage.

Capital Investments

	For the years ended December 31,	
(in millions)	2020	2019
E&P Capital Investments by Type		
Exploratory and development drilling, including workovers	$ 692	$ 838
Acquisition of properties	37	55
Seismic expenditures	—	3
Water infrastructure project	9	35
Other	17	21
Capitalized interest and expenses	144	186
Total E&P capital investments	$ 899	$ 1,138
E&P Capital Investments by Area		
Northeast Appalachia	$ 362	$ 365
Southwest Appalachia	510	710
Other [(1)]	27	63
Total E&P capital investments	$ 899	$ 1,138

(1) Includes $9 million and $35 million for the years ended December 31, 2020 and 2019 related to our water infrastructure project.

- The decrease in 2020 E&P capital investing, as compared to the prior year, resulted from reduced average well costs as well as our commitment to invest within our cash flows from operations, which are heavily dependent on commodity prices, supplemented by the remaining proceeds from the Fayetteville Shale sale.

- In 2020, we drilled 98 wells (86 of which were spud in 2020), completed 96 wells, placed 100 wells to sales and had 42 wells in progress at year-end.
- Of the 42 wells in progress at year-end, 26 and 16 were located in Northeast Appalachia and Southwest Appalachia, respectively.

We refer you to "Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Capital Investing" within Item 7 of Part II of this Annual Report for additional discussion of the factors that could impact our planned capital investments in 2021.

Sales, Delivery Commitments and Customers

Sales. The following tables present historical information about our production volumes for natural gas, oil and NGLs and our average realized natural gas, oil and NGL sales prices:

	For the years ended December 31,	
	2020	2019
Average net daily production *(MMcfe/day)*	2,403	2,133
Production:		
Natural gas *(Bcf)*	694	609
Oil *(MBbls)*	5,141	4,696
NGLs *(MBbls)*	25,927	23,620
Total production *(Bcfe)*	880	778

- The increase in production in 2020 resulted primarily from a 88 Bcfe increase in net production in Southwest Appalachia and a 14 Bcf increase in production in Northeast Appalachia. These increases included 28 Bcfe in production from our acreage newly acquired through the Merger.

Average Realized Prices

	For the years ended December 31,	
	2020	2019
Natural Gas Price:		
NYMEX Henry Hub Price *($/MMBtu)* (1)	$ 2.08	$ 2.63
Discount to NYMEX (2)	(0.74)	(0.65)
Average realized gas price, excluding derivatives *($/Mcf)*	$ 1.34	$ 1.98
Gain on settled financial basis derivatives *($/Mcf)*	0.11	—
Gain on settled commodity derivatives *($/Mcf)*	0.25	0.20
Average realized gas price, including derivatives *($/Mcf)*	$ 1.70	$ 2.18
Oil Price:		
WTI oil price *($/Bbl)*	$ 39.40	$ 57.03
Discount to WTI	(10.20)	(10.13)
Average realized oil price, excluding derivatives *($/Bbl)*	$ 29.20	$ 46.90
Gain on settled derivatives *($/Bbl)*	17.71	2.66
Average realized oil price, including derivatives *($/Bbl)*	$ 46.91	$ 49.56
NGL Price:		
Average realized NGL price, excluding derivatives *($/Bbl)*	$ 10.24	$ 11.59
Gain on settled derivatives *($/Bbl)*	0.91	2.05
Average realized NGL price, including derivatives *($/Bbl)*	$ 11.15	$ 13.64
Percentage of WTI, excluding derivatives	26 %	20 %
Total Weighted Average Realized Price:		
Excluding derivatives *($/Mcfe)*	$ 1.53	$ 2.18
Including derivatives *($/Mcfe)*	$ 1.94	$ 2.42

(1) Based on last day settlement prices from monthly futures contracts.

(2) This discount includes a basis differential, a heating content adjustment, physical basis sales, third-party transportation charges and fuel charges, and excludes financial basis hedges.

Sales of natural gas, oil and NGL production are conducted under contracts that reflect current prices and are subject to seasonal price swings. We are unable to predict changes in the market demand and price for these commodities, including changes that may be induced by the effects of weather on demand for our production. We regularly enter into various derivative and other financial arrangements with respect to a portion of our projected production to support certain desired levels of cash flow and to minimize the impact of price fluctuations. We limit derivative agreements to counterparties with appropriate credit standings, and our policies prohibit speculation.

As of December 31, 2020, we had the following commodity price derivatives in place on our targeted future production:

	For the years ended December 31,		
	2021	2022	2023
Natural gas *(Bcf)*	751	378	87
Oil *(MBbls)*	6,631	2,155	878
Ethane *(MBbls)*	6,473	1,710	—
Propane *(MBbls)*	6,974	2,120	—
Normal Butane *(MBbls)*	2,004	667	—
Natural Gasoline *(MBbls)*	1,936	643	—

As of February 25, 2021, we had the following commodity price derivatives in place on our targeted 2020 and future production:

	For the years ended December 31,		
	2021	2022	2023
Natural gas *(Bcf)*	761	454	103
Oil *(MBbls)*	6,631	2,850	878
Ethane *(MBbls)*	6,560	1,893	—
Propane *(MBbls)*	7,149	2,727	—
Normal Butane *(MBbls)*	2,092	794	—
Natural Gasoline *(MBbls)*	2,021	765	—

We intend to use derivatives to limit the impact of price volatility on a large portion of expected future production volumes to ensure certain desired levels of cash flow. We refer you to Item 7A of Part II of this Annual Report, "Quantitative and Qualitative Disclosures about Market Risk," for further information regarding our derivatives and risk management as of December 31, 2020.

During 2020, the average price we received for our natural gas production, excluding the impact of derivatives and including the cost of transportation, was approximately $0.74 per Mcf lower than average New York Mercantile Exchange, or NYMEX, prices. Differences between NYMEX and price realized (basis differentials) are due primarily to locational differences and transportation cost.

As of December 31, 2020, we have entered into physical sales arrangements to limit the impact of basis volatility on approximately 217 Bcf and 65 Bcf of our 2021 and 2022 expected natural gas production, respectively, at a basis differential to NYMEX natural gas price of approximately ($0.24) per MMBtu and ($0.35) per MMBtu for 2021 and 2022, respectively.

We have also entered into financial basis swaps for approximately 219 Bcf, 139 Bcf, 47 Bcf, 11 Bcf and 4 Bcf of our 2021, 2022, 2023, 2024, and 2025 expected natural gas production, respectively, at a basis differential to NYMEX natural gas price of approximately ($0.21) per MMBtu, ($0.33) per MMBtu, ($0.45) per MMBtu, ($0.60) per MMBtu and ($0.59) per MMBtu for 2021, 2022, 2023, 2024 and 2025, respectively, as of December 31, 2020.

We refer you to Note 6 to the consolidated financial statements included in this Annual Report for additional discussion about our derivatives and risk management activities.

Delivery Commitments. As of December 31, 2020, we had natural gas delivery commitments of 486 Bcf in 2021 and 113 Bcf in 2022 under existing agreements. These amounts are well below our expected 2021 natural gas production from Northeast Appalachia and Southwest Appalachia and expected 2022 production from our available reserves, which are not subject to any priorities or curtailments that may affect quantities delivered to our customers or any priority allocations or price limitations imposed by federal or state regulatory agencies, or any other factors beyond our control that may affect our ability to meet our delivery commitments other than those discussed in Item 1A "Risk Factors" of Part I of this Annual Report. We expect to be able to fulfill all of our short-term and long-term delivery commitments to provide natural gas from our own production of available reserves; however, if we are unable to do so, we may have to purchase natural gas at market to fulfill our obligations.

Customers. Our E&P production is marketed primarily by our Marketing segment. Our customers include major energy companies, utilities and industrial purchasers of natural gas. For the year ended December 31, 2020, one purchaser accounted for 10% of our revenues. A default on this account could have a material impact on the Company, but we do not believe that there is a material risk of default. No other purchasers accounted for greater than 10% of consolidated revenues. During the year ended December 31, 2019, no single third-party purchaser accounted for 10% or more of our consolidated revenues. We believe that the loss of any one customer would not have an adverse effect on our ability to sell our natural gas, oil and NGL production.

Competition

All phases of the natural gas and oil industry are highly competitive. We compete in the acquisition and disposition of properties, the search for and development of reserves, the production and marketing of natural gas, oil and NGLs, and the securing of labor, services and equipment required to conduct our operations. Our competitors include major oil and natural gas companies, other independent oil and natural gas companies and individual producers. Many of these competitors have financial and other resources that substantially exceed those available to us. Consequently, we will encounter competition that may affect both the price we receive and contract terms we must offer. We also face competition in accessing pipeline and other services to transport our product to market. Likewise, there are substitutes for the commodities we produce, such as other fuels for power generation, heating and transportation, and those markets in effect compete with us.

We cannot predict whether and to what extent any regulatory changes initiated by the Federal Energy Regulatory Commission, or the FERC, or any other new energy legislation or regulations will achieve the goal of increasing competition, lessening preferential treatment and enhancing transparency in markets in which our natural gas production is sold. Similarly, we cannot predict whether legal constraints that have hindered the development of new transportation infrastructure, particularly in the northeastern United States, will continue. However, we do not believe that we will be disproportionately affected as compared to other natural gas and oil producers and marketers by any action taken by the FERC or any other legislative or regulatory body or the status of the development of transportation facilities.

Regulation

Producing natural gas, oil and NGL resources and transporting and selling production historically have been heavily regulated. For example, state governments regulate the location of wells and establish the minimum size for spacing units. Permits typically are required before drilling. State and local government zoning and land use regulations may also limit the locations for drilling and production. Similar regulations can also affect the location, construction and operation of gathering and other pipelines needed to transport production to market. In addition, various suppliers of goods and services may require licensing.

Currently in the United States, the price at which natural gas, oil or NGLs may be sold is not regulated. Congress has imposed price regulation from time to time, and there can be no assurance that the current, less stringent regulatory approach will continue. In 2015, the federal government repealed a 40-year ban on the export of crude oil. The export of natural gas continues to require federal permits. Broader freedom to export could lead to higher prices. In addition, the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”) and the rules that the U.S. Commodity Futures Trading Commission, (the “CFTC”), the SEC, and certain other regulators have issued thereunder regulate certain swaps, futures and options contracts in the major energy markets, including for natural gas, oil and NGLs

Producing and transporting natural gas, oil and NGLs is also subject to extensive environmental regulation. We refer you to “Other – Environmental Regulation” in Item 1 of Part 1 of this Annual Report and the risk factor “We, our service providers and our customers are subject to complex federal, state and local laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities” in Item 1A of Part I of this Annual Report for a discussion of the impact of environmental regulation on our business.

Marketing

We engage in marketing activities which primarily support our E&P operations and generate revenue through the marketing of natural gas, oil and NGLs.

	For the years ended December 31,	
	2020	2019
Marketing revenues *(in millions)*	$ 2,145	$ 2,849
Other revenues *(in millions)*	—	1
Total operating revenues *(in millions)*	$ 2,145	$ 2,850
Operating income (loss) *(in millions)*	$ (7)	$ (13)
Volumes marketed *(Bcfe)*	1,138	1,101
Percent natural gas production marketed from affiliated E&P operations	89 %	79 %
Percent oil and NGL production marketed from affiliated E&P operations	81 %	61 %

- Operating loss decreased $6 million for the year ended December 31, 2020, compared to 2019, primarily due to a $2 million decrease in operating costs and expenses. In addition, marketing operating loss for the year ended December 31, 2019 included a $3 million impairment of non-core gathering assets, a $2 million loss on the sale of operating assets and $1 million in gas storage gains recorded in other operating revenues.
- Marketing revenues decreased in 2020, compared to 2019, primarily as a 27% decrease in the price received for volumes marketed more than offset a 37 Bcfe increase in marketed volumes.
- Cash flow from operations of $317 million generated by our Marketing segment decreased in 2020, compared to 2019, as a $706 million decrease in cash operating costs and expenses was offset by a $705 million decrease in operating revenues and a $441 million decrease primarily related to timing differences of payables and receivables between the respective periods.

Marketing

We attempt to capture opportunities related to the marketing and transportation of natural gas, oil and NGLs primarily involving the marketing of our own equity production and that of royalty owners in our wells. Additionally, we manage portfolio and locational, or basis, risk, acquire transportation rights on third-party pipelines and, in limited circumstances, purchase third-party natural gas to fulfill commitments specific to a geographic location.

Northeast Appalachia. Our transportation portfolio in Northeast Appalachia is highly diversified and allows us to access premium city-gate markets as well as to deliver natural gas from the Appalachian basin area to the southeast United States. The capacity agreements contain multiple extension and reduction options that allow us to right-size our transportation portfolio as needed for our production or to capture future market opportunities. The table below details our firm transportation, firm sales and total takeaway capacity over the next three years as of February 25, 2021:

	For the year ended December 31,		
(MMBtu/d)	2021	2022	2023
Firm transportation [(1)]	1,252,574	938,347	709,498
Firm sales	341,744	127,439	29,864
Total firm takeaway – Northeast Appalachia	1,594,318	1,065,786	739,362

(1) We have extension options and potential contract renewal capacity of 332,000 MMBtu per day for 2022 and 559,000 MMBtu per day for 2023 for Northeast Appalachia.

Southwest Appalachia. Our transportation portfolio for all products in Southwest Appalachia, including commitments acquired through the Montage Merger, allows us to capitalize on strengthening markets and provides a path for production growth. Agreements with ET Rover Pipeline LLC and Columbia Pipeline Group, Inc.'s Mountaineer Xpress and Gulf Xpress pipelines allow us to access high-demand markets along the Gulf Coast while also capturing materially improving in-basin pricing, and our agreements with Rockies Express Pipeline LLC provide access to premium Midwest markets. In addition to our natural gas transportation, we have ethane take-away capacity that provides direct access to Mont Belvieu pricing. The table below details our natural gas firm transportation, firm sales and total takeaway capacity over the next three years as of February 25, 2021:

	For the year ended December 31,		
(MMBtu/d)	2021	2022	2023
Firm transportation [(1)]	1,102,016	1,279,900	1,240,539
Firm sales	294,722	47,817	47,817
Total firm takeaway – Southwest Appalachia	1,396,738	1,327,717	1,288,356

(1) We have extension options and potential contract renewal capacity of 76,900 MMBtu per day for 2022 and 76,900 MMBtu per day for 2023 for Southwest Appalachia.

Demand Charges

As of December 31, 2020, our obligations for demand and similar charges under the firm transportation agreements and gathering agreements totaled approximately $8.5 billion, $531 million of which related to access capacity on future pipeline and gathering infrastructure projects that still require the granting of regulatory approvals and additional construction efforts. We also have guarantee obligations of up to $923 million of that amount. In February 2020, we were notified that the proposed Constitution pipeline project was cancelled and that we were released from a firm transportation agreement with its sponsor.

In the first quarter of 2019, we agreed to purchase firm transportation with pipelines in Appalachia starting in 2021 and running through 2032 totaling $357 million in total contractual commitments, of which the seller has agreed to reimburse us for $133 million.

We refer you to Note 10 to the consolidated financial statements included in this Annual Report for further details on our demand charges and the risk factor "We have made significant investments in oilfield services businesses, including our drilling rigs, water infrastructure and pressure pumping equipment, to lower costs and secure inputs for our operations and transportation for our production. If our development and production activities are curtailed or disrupted, we may not recover our investment in these activities, which could adversely impact our results of operations. In addition, our continued expansion of these operations may adversely impact our relationships with third-party providers" in Item 1A of Part I of this Annual Report.

Competition

Our marketing activities compete with numerous other companies offering the same services, many of which possess larger financial and other resources than we have. Some of these competitors are other producers and affiliates of companies with extensive pipeline systems that are used for transportation from producers to end users. Other factors affecting competition are the cost and availability of alternative fuels, the level of consumer demand and the cost of and proximity to pipelines and other transportation facilities. We believe that our ability to compete effectively within the marketing segment in the future depends upon establishing and maintaining strong relationships with customers.

Customers

Our marketing customers include major energy companies, utilities and industrial purchasers of natural gas. For the year ended December 31, 2020, one purchaser accounted for 10% of our revenues. A default could have a material impact on the Company, but we do not believe that there is a material risk of default. No other purchasers accounted for greater than 10% of consolidated revenues. During the year ended December 31, 2019, no single third-party purchaser accounted for 10% or more of our consolidated revenues. We believe that the loss of any one customer would not have an adverse effect on our ability to sell our natural gas, oil and NGL production.

Regulation

The transportation of natural gas, oil and NGLs is heavily regulated. FERC regulates the rates and the terms and conditions of transportation service provided by interstate natural gas, crude oil and NGL pipelines. State governments typically must authorize the construction of pipelines for intrastate service. Moreover, the rates charged for intrastate transportation by pipeline are subject to regulation by state regulatory commissions. The basis for intrastate pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate pipeline rates, varies from state to state. Currently, all pipelines we own are intrastate and immaterial to our operations.

State and local permitting, zoning and land use regulations can affect the location, construction and operation of gathering and other pipelines needed to transport production to market, and the lack of new pipeline capacity can limit our ability to reach relevant markets for the sale of the commodities we produce.

The transportation of natural gas and oil is also subject to extensive environmental regulation. We refer you to "Other – Environmental Regulation" in Item 1 of Part I of this Annual Report and the risk factor "We, our service providers and our customers are subject to complex federal, state and local laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities" in Item 1A of Part I of this Annual Report for a discussion of the impact of environmental regulation on our business.

Other

We currently have no significant business activity outside of our E&P and Marketing segments.

Environmental Regulation

General. Our operations are subject to environmental regulation in the jurisdictions in which we operate. These laws and regulations require permits for drilling wells and the maintenance of bonding requirements to drill or operate wells, and also regulate the spacing and location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells and the prevention and cleanup of pollutants and other matters. We maintain insurance for clean-up costs in limited instances arising out of sudden and accidental events, but otherwise we may not be fully insured against all such risks. Although future environmental obligations are not expected to have a material impact on the results of our operations or financial condition, there can be no assurance that future developments, such as increasingly stringent environmental laws or enforcement thereof, will not cause us to incur material environmental liabilities or costs.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal fines and penalties and the imposition of injunctive relief. Certain laws and legal principles can make us liable for environmental damage to properties we previously owned, and although we generally require purchasers to assume that liability, there is no assurance that they will have sufficient funds should a liability arise. Changes in environmental laws and regulations occur frequently, and any changes may result in more stringent and costly waste handling, storage, transportation, disposal or cleanup requirements. We do not expect continued compliance with existing requirements to have a material adverse impact on us, but there can be no assurance that this will continue in the future. We refer you to "Other – Environmental Regulation" in Item 1 of Part 1 of this Annual Report and the risk factor "We, our service providers and our customers are subject to complex federal, state and local laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities" in Item 1A of Part I of this Annual Report for a discussion of the impact of environmental regulation on our business.

The following is a summary of the more significant existing environmental and worker health and safety laws and regulations to which we are subject.

Generation and Disposal of Wastes. The Comprehensive Environmental Response, Compensation, and Liability Act, as amended, also known as CERCLA or the "Superfund law," imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the current or former owner or operator of a site where the release occurred, as well as persons that transported or disposed, or arranged for the transportation or disposal of, the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

The Resource Conservation and Recovery Act, as amended, or RCRA, generally does not regulate wastes generated by the exploration and production of natural gas and oil. RCRA specifically excludes from the definition of hazardous waste "drilling fluids, produced waters and other wastes associated with the exploration, development or production of oil, natural gas or geothermal energy." However, legislative and regulatory initiatives have been considered from time to time that would reclassify certain natural gas and oil exploration and production wastes as "hazardous wastes," which would make the reclassified wastes subject to much more stringent handling, disposal and clean-up requirements. If such measures were to be enacted, it could have a significant impact on our operating costs. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste oils, may be regulated as hazardous waste.

The Clean Water Act, as amended, or CWA, and analogous state laws, impose restrictions and strict controls regarding the discharge of produced waters and other natural gas and oil waste into regulated waters. Permits must be obtained to discharge pollutants to regulated waters and to conduct construction activities in waters and wetlands. The CWA and similar state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of pollutants and unauthorized discharges of reportable quantities of oil and other hazardous substances. The EPA has adopted regulations requiring certain natural gas and oil exploration and production facilities to obtain permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans.

The Oil Pollution Act, as amended, or OPA, and regulations promulgated thereunder impose a variety of requirements on "responsible parties" related to the prevention of oil spills and liability for damages resulting from such spills into regulated waters. A "responsible party" includes the owner or operator of an onshore facility, pipeline or vessel, or the lessee or permittee of the area in which an offshore facility is located. OPA assigns liability to each responsible party for oil cleanup costs and a variety of public and private damages. Although liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Few defenses exist to the liability imposed by OPA. OPA imposes ongoing requirements on a responsible party, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill. Although oil accounted for only 4% of our total production in 2020 and 2019 and 2% in 2018, we expect this percentage to increase as we continue to develop our Southwest Appalachia assets.

We own or lease, and have in the past owned or leased, onshore properties that for many years have been used for or associated with the exploration for and production of natural gas and oil. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us and/or on or under other locations where such wastes have been taken for disposal. In addition, some of these properties have been operated by third parties whose treatment and disposal or release of wastes was not under our control. Under CERCLA, the CWA, RCRA and analogous state laws, we could be required to remove or remediate previously disposed wastes (including waste disposed of or released by prior owners or operators) or property contamination (including groundwater contamination by prior owners or operators), or to perform remedial plugging or closure operations to prevent future contamination.

Air Emissions. The Clean Air Act, as amended, restricts emissions into the atmosphere. Various activities we conduct as part of our operations, such as drilling, pumping and the use of vehicles, can result in emissions to the environment. We must obtain permits, typically from local authorities, to conduct various regulated activities. Federal and state governmental agencies are looking into the issues associated with methane and other emissions from oil and natural gas activities, and further regulation could increase our costs or restrict our ability to produce. Although methane emissions are not currently regulated at the federal level, we are required to report emissions of various greenhouse gases, including methane.

Threatened and Endangered Species. The Endangered Species Act and comparable state laws protect species threatened with possible extinction. Protection of threatened and endangered species may have the effect of prohibiting or delaying us from obtaining drilling and other permits and may include restrictions on road building and other activities in areas containing the affected species or their habitats. Based on the species that have been identified to date, we do not believe there are any species protected under the Endangered Species Act that would materially and adversely affect our operations at this time.

Hydraulic Fracturing. We utilize hydraulic fracturing in drilling wells as a means of maximizing their productivity. It is an essential and common practice in the oil and gas industry used to stimulate the production of oil, natural gas, and associated liquids from dense and deep rock formations. Hydraulic fracturing involves using water, sand, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow the flow of hydrocarbons into the wellbore.

In the past several years, there has been an increased focus on the environmental aspects of hydraulic fracturing, both in the United States and abroad. In the United States, hydraulic fracturing is typically regulated by state oil and natural gas commissions, but federal agencies have started to assert regulatory authority over certain aspects of the process. For example, the Environmental Protection Agency, or EPA, issued final rules effective as of October 15, 2012 that subject oil and gas operations (production, processing, transmission, storage and distribution) to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or NESHAP programs. In May 2016, the EPA finalized additional regulations to control methane and volatile organic compound ("VOC") emissions from certain oil and gas equipment and operations. In September 2018, the EPA issued proposed revisions to those regulations, which would reduce certain obligations thereunder. In September 2020, the EPA finalized further amendments to the standards that removed the transmission and storage segments from the oil and natural gas source category and rescinded the methane-specific requirements for production and processing facilities. Several lawsuits were filed challenging these amendments, and the U.S. Court of Appeals for the D.C. Circuit ordered an administrative stay of these amendments shortly after they were finalized. Although the administrative stay was lifted in October 2020, which brought the amendments into effect, the amendments may be subject to reversal under a new presidential administration. As a result, we cannot predict the scope of any final methane regulatory requirements or the cost to comply with such requirements. The EPA also finalized pretreatment standards that would prohibit the indirect discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly owned treatment works. Based on our current operations and practices, management believes such newly promulgated rules will not have a material adverse impact on our financial position, results of operations or cash flows but these matters are subject to inherent uncertainties and management's view may change in the future.

In addition, there are certain governmental reviews either underway or proposed that focus on environmental aspects of hydraulic fracturing practices. A number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. For example, in December 2016, the EPA released its final report regarding the potential impacts of hydraulic fracturing on drinking water resources, concluding that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under certain circumstances such as water withdrawals for fracturing in times or areas of low water availability, surface spills during the management of fracturing fluids, chemicals or produced water, injection of fracturing fluids into wells with inadequate mechanical integrity, injection of fracturing fluids directly into groundwater resources, discharge of inadequately treated fracturing wastewater to surface waters and disposal or storage of fracturing wastewater in unlined pits. The results of these studies could lead federal and state governments and agencies to develop and implement additional regulations.

Although the prior administration relaxed many regulations adopted in the latter part of the prior administration, that trend is likely to reverse under the new administration. In January 2021, the new administration announced a 60-day suspension of new oil and gas leasing and drilling permits on federal lands, and subsequently signed an Executive Order directing the Secretary of the Interior to pause new oil and natural gas leases on public lands or in offshore waters pending completion of a comprehensive review and reconsideration of federal oil and gas permitting and leasing practices. In addition, some states in which we operate have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, waste disposal and well construction requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. In the event state, local, or municipal legal restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling and/or completion of wells.

Increased regulation and attention given to the hydraulic fracturing process has led to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil, natural gas, and associated liquids including from the development of shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of additional federal, state or local laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells, increased compliance costs and time, which could adversely affect our financial position, results of operations and cash flows. In addition, various officials and candidates at the federal, state and local levels, including some presidential candidates, have proposed banning hydraulic fracturing altogether. We refer you to the risk factor "We, our service providers and our customers are subject to complex federal, state and local laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities" in Item 1A of Part I of this Annual Report.

In addition, concerns have been raised about the potential for seismic activity to occur from the use of underground injection control wells, a predominant method for disposing of waste water from oil and gas activities. New rules and regulations may be developed to address these concerns, possibly limiting or eliminating the ability to use disposal wells in certain locations and increasing the cost of disposal in others. We utilize third parties to dispose of waste water associated with our operations. These third parties may operate injection wells and may be subject to regulatory restrictions relating to seismicity.

Greenhouse Gas Emissions. In response to findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to human health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, establish Prevention of Significant Deterioration, or PSD, construction and Title V operating permit reviews for certain large stationary sources. Facilities required to obtain PSD permits for their greenhouse gas emissions also will be required to meet "best available control technology" standards that will be established on a case-by case basis. One of our subsidiaries operates compressor stations, which are facilities that are required to adhere to the PSD or Title V permit requirements. EPA rulemakings related to greenhouse gas emissions could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources.

The EPA also has adopted rules requiring the monitoring and reporting of greenhouse gas emissions from specified onshore and offshore oil and gas production sources in the United States on an annual basis, which include certain of our operations. Although Congress from time to time has considered legislation to reduce emissions of greenhouse gases, there has not been significant activity in the form of adopted legislation to reduce greenhouse gas emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of states, including states in which we operate, have enacted or passed measures to track and reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and regional greenhouse gas cap-and-trade programs. Most of these cap-and-trade programs require major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall greenhouse gas emission reduction goal is achieved. These reductions may cause the cost of allowances to escalate significantly over time.

The adoption and implementation of regulations that require reporting of greenhouse gases or otherwise limit emissions of greenhouse gases from our equipment and operations could require us to incur costs to monitor and report on greenhouse gas emissions or install new equipment to reduce emissions of greenhouse gases associated with our operations. In addition, these regulatory initiatives could drive down demand for our products by stimulating demand for alternative forms of energy that do not rely on combustion of fossil fuels that serve as a major source of greenhouse gas emissions, which could have a material adverse effect on our business, financial condition, results of operations and cash flows. At the same time, new laws and regulations are prompting power producers to shift from coal to natural gas, which is increasing demand.

Further, in December 2015, over 190 countries, including the United States, reached an agreement to reduce global greenhouse gas emissions (the "Paris Agreement"). The Paris Agreement entered into effect in November 2016 after more than 70 nations, including the United States, ratified or otherwise indicated their intent to be bound by the agreement. In November 2019, the United States initiated the year-long process of formally withdrawing from the Paris Agreement, which resulted in an effective exit date of November 2020. However, in January 2021, the new administration announced that the U.S. would be rejoining the Paris Agreement. To the extent that the United States and other countries implement this agreement or impose other climate change regulations on the oil and gas industry, it could have an adverse effect on our business.

Employee Health and Safety. Our operations are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes, whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens.

Canada. Our activities in Canada have, to date, been limited to certain geological and geophysical activities and now are subject to a moratorium. If and when the moratorium ends and should we begin drilling and development activities in New Brunswick, we will be subject to federal, provincial and local environmental regulations.

Human Capital

We aim to provide a safe, healthy, respectful and fair workplace for all employees. We focus our actions to ensure our people are engaged and have the necessary tools and skills to be highly successful.

Southwestern Energy is committed to respect in the workplace. All employees participate in a program addressing workplace behavior and respect on an annual basis. Our Human Rights Policy, which is consistent with the International Labour Organization's Declaration on Fundamental Principles and Rights at Work, underscores our commitment to our workforce and extends to vendors and contractors. All decisions regarding recruiting, hiring, training, evaluation, assignment, advancement and termination of employment are made without unlawful discrimination on the basis of race, color, national origin, ancestry, citizenship, sex, sexual orientation, gender identity or expression, religion, age, pregnancy, disability, present military status or veteran status, genetic information, marital status or any other factor that the law protects from employment discrimination. Compensation is based on several primary factors, including performance, skills, years of experience, time in position and market data. Through our SWomeN initiatives, we actively seek to retain and develop our female talent.

Southwestern Energy leaders, including senior management, are evaluated on and held accountable for the health, safety and environmental ("HSE") performance of their teams. We include HSE considerations in every business decision we make and foster a true "ONE Team" culture, where our employees and contractors work together to uphold the same high safety standards.

Our response to COVID-19 in 2020 was driven by our long-standing commitment to safety. We formed a cross-functional Incident Response Team ("IRT") on March 12, 2020 to manage and oversee prolonged company-wide response and mitigation efforts. The IRT met daily and provided real-time and weekly reports to senior management. Increased safeguards for employees and contractors were put in place, including mask requirements, social distancing, isolation and quarantine procedures, dynamic office closures and remote work protocols, rapid cleaning response protocols, temperature screenings at office locations, COVID-19 questionnaires and modified protocols as necessary based on continuous monitoring of relevant data and guidance. We have also provided additional benefits to our employees including COVID-19 testing for all office and field employees and their families, paid time off for non-exempt workers required to isolate or quarantine, and have made plans to make the COVID-19 vaccine available to employees and their families who want it.

Additional information about our commitment to human capital is available on our website and in other company filings available on our website. Note that the information on our website is not incorporated by reference into this filing.

As of December 31, 2020, we had 900 total employees, a decrease of 2% compared to year-end 2019. None of our employees were covered by a collective bargaining agreement at year-end 2020. We believe that our relationships with our employees are good.

Executive Officers of the Registrant

The following table shows certain information as of February 25, 2021 about our executive officers, as defined in Rule 3b-7 of the Securities Exchange Act of 1934:

Name	Age	Officer Position
William J. Way	61	President and Chief Executive Officer
Michael E. Hancock	44	Vice President and Chief Financial Officer (Interim)
Clayton A. Carrell	55	Executive Vice President and Chief Operating Officer
Derek W. Cutright	43	Senior Vice President – Southwest Appalachia
John P. Kelly	50	Senior Vice President – Northeast Appalachia
Quentin Dyson	51	Senior Vice President – Operations Services
Jason Kurtz	50	Vice President – Marketing and Transportation
Chris Lacy	43	Vice President, General Counsel and Secretary
Andy Huggins	40	Vice President – Business and Commercial Development
Carina Gillenwater	45	Vice President – Human Resources

Mr. Way was appointed Chief Executive Officer in January 2016. Prior to that, he served as Chief Operating Officer since 2011, having also been appointed President in December 2014. Prior to joining the Company, he was Senior Vice President, Americas of BG Group plc with responsibility for E&P, Midstream and LNG operations in the United States, Trinidad and Tobago, Chile, Bolivia, Canada and Argentina since 2007.

Mr. Hancock was appointed Vice President and Chief Financial Officer (Interim) in January 2021. Prior to that, he served as Vice President Financial Planning and Analysis since 2017. Prior to that, he served in various finance and accounting leadership roles since joining the Company in February 2010.

Mr. Carrell was appointed Executive Vice President and Chief Operating Officer in December 2017. Prior to joining the Company, he was Executive Vice President and Chief Operating Officer of EP Energy since 2012.

Mr. Cutright was appointed Senior Vice President of Southwest Appalachia Division in September 2019; he served as Vice President & General Manager of Southwest Appalachia since 2016. Prior to that, he served in various operational leadership roles since joining the Company in December 2008.

Mr. Kelly was appointed Senior Vice President of Northeast Appalachia in October 2018, having previously served as Senior Vice President – Fayetteville since in 2017. Prior to joining the Company, he was President and Chief Executive Officer of Cantera Energy since 2012.

Mr. Dyson was appointed Senior Vice President of Operations Services in April 2019. He held Vice President roles at EP Energy and BP before joining SWN in January 2018 as Vice President – Operations Services.

Mr. Kurtz was appointed Vice President of Marketing and Transportation in May 2011. Prior to that, he served in various marketing roles since joining the Company in May 1997.

Mr. Lacy was appointed Vice President, General Counsel and Secretary in 2020. Prior to that, he served Associate General Counsel and Assistant Secretary and various other roles in the legal department since joining the Company in 2014.

Mr. Huggins has served as Vice President of Commercial and Business Development since March 2018. Prior to that he served in various operational and technical leadership roles since joining the Company in 2007.

Mrs. Gillenwater was appointed Vice President of Human Resources in June 2018. Prior to joining the Company, she served as Global Vice President of Human Resources at Nabors Industries and Vice President of Human Resources at Smith International / Schlumberger Ltd.

There are no family relationships between any of the Company's directors or executive officers.

GLOSSARY OF CERTAIN INDUSTRY TERMS

The definitions set forth below include indicated terms in this Annual Report. All natural gas reserves reported in this Annual Report are stated at the legal pressure base of the state or area where the reserves exist and at 60 degrees Fahrenheit. All currency amounts are in U.S. dollars unless specified otherwise.

"Acquisition of properties" Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties. For additional information, see the SEC's definition in Rule 4-10(a) (1) of Regulation S-X, a link for which is available at the SEC's website.

"Available reserves" Estimates of the amounts of natural gas, oil and NGLs which the registrant can produce from current proved developed reserves using presently installed equipment under existing economic and operating conditions and an estimate of amounts that others can deliver to the registrant under long-term contracts or agreements on a per-day, per-month, or per-year basis. For additional information, see the SEC's definition in Item 1207(d) of Regulation S-K, a link for which is available at the SEC's website.

"Basis differential" The difference in price for a commodity between a market index price and the price at a specified location.

"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 equivalent. Determined using the ratio of one barrel of oil or natural gas liquids to six Mcf of natural gas.

"Btu" One British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

"Deterministic estimate" The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure. For additional information, see the SEC's definition in Rule 4-10(a) (5) of Regulation S-X, a link for which is available at the SEC's website.

"Developed oil and gas reserves" Developed oil and natural gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

For additional information, see the SEC's definition in Rule 4-10(a) (6) of Regulation S-X, a link for which is available at the SEC's website.

"Development costs" Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing natural gas, oil and NGLs. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.

(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.

(iv) Provide improved recovery systems.

For additional information, see the SEC's definition in Rule 4-10(a) (7) of Regulation S-X, a link for which is available at the SEC's website.

"Development project" A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project. For additional information, see the SEC's definition in Rule 4-10(a) (8) of Regulation S-X, a link for which is available at the SEC's website.

"Development well" A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive. For additional information, see the SEC's definition in Rule 4-10(a) (9) of Regulation S-X, a link for which is available at the SEC's website.

"E&P" Exploration for and production of natural gas, oil and NGLs.

"Economically producible" The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities. For additional information, see the SEC's definition in Rule 4-10(a) (10) of Regulation S-X, a link for which is available at the SEC's website.

"Estimated ultimate recovery (EUR)" Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date. For additional information, see the SEC's definition in Rule 4-10(a) (11) of Regulation S-X, a link for which is available at the SEC's website.

"Exploitation" The development of a reservoir to extract its natural gas and/or oil.

"Exploratory well" An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section. For additional information, see the SEC's definition in Rule 4-10(a) (13) of Regulation S-X, a link for which is available at the SEC's website.

"Field" An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious, strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms structural feature and stratigraphic condition are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc. For additional information, see the SEC's definition in Rule 4-10(a) (15) of Regulation S-X, a link for which is available at the SEC's website.

"Gross well or acre" A well or acre in which the registrant owns a working interest. The number of gross wells is the total number of wells in which the registrant owns a working interest. For additional information, see the SEC's definition in Item 1208(c)(1) of Regulation S-K, a link for which is available at the SEC's website.

"Gross working interest" Gross working interest is the working interest in a given property plus the proportionate share of any royalty interest, including overriding royalty interest, associated with the working interest.

"Henry Hub" A common market pricing point for natural gas in the United States, located in Louisiana.

"Hydraulic fracturing" A process whereby fluids mixed with proppants are injected into a wellbore under pressure in order to fracture, or crack open, reservoir rock, thereby allowing oil and/or natural gas trapped in the reservoir rock to travel through the fractures and into the well for production.

"Infill drilling" Drilling wells in between established producing wells to increase recovery of natural gas, oil and NGLs from a known reservoir.

"Internal Rate of Return" Discount rate at which net present value of cash flow is zero.

"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 equivalent, with liquids converted to an equivalent volume of natural gas using the ratio of one barrel of oil to six Mcf of natural gas.

"MMBbls" One million barrels of oil or other liquid hydrocarbons.

"MMBtu" One million British thermal units (Btus).

"MMcf" One million cubic feet of natural gas.

"MMcfe" One million cubic feet of natural gas equivalent, with liquids converted to an equivalent volume of natural gas using the ratio of one barrel of oil to six Mcf of natural gas.

"Mont Belvieu" A pricing point for North American NGLs.

"Net acres" The sum, for any area, of the products for each tract of the acres in that tract multiplied by the working interest in that tract. For additional information, see the SEC's definition in Item 1208(c)(2) of Regulation S-K, a link for which is available at the SEC's website.

"Net revenue interest" Economic interest remaining after deducting all royalty interests, overriding royalty interests and other burdens from the working interest ownership.

"Net well" The sum, for all wells being discussed, of the working interests in those wells. For additional information, see the SEC's definition in Item 1208(c)(2) of Regulation S-K, a link for which is available at the SEC's website.

"NGLs" Natural gas liquids (includes ethane, propane, butane, isobutane, pentane and pentanes plus).

"NYMEX" The New York Mercantile Exchange, on which spot and future contracts for natural gas and other commodities are traded.

"Operating interest" An interest in natural gas and oil that is burdened with the cost of development and operation of the property.

"Overriding royalty interest" A fractional, undivided interest or right to production or revenues, free of costs, of a lessee with respect to an oil or natural gas well, that overrides a working interest.

"Play" A term applied to a portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential oil and natural gas reserves.

"Pressure pumping spread" All of the equipment needed to carry out a hydraulic fracturing job.

"Probabilistic estimate" The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence. For additional information, see the SEC's definition in Rule 4-10(a) (19) of Regulation S-X, a link for which is available at the SEC's website.

"Producing property" A natural gas and oil property with existing production.

"Productive wells" Producing wells and wells mechanically capable of production. For additional information, see the SEC's definition in Item 1208(c)(3) of Regulation S-K, a link for which is available at the SEC's website.

"Proppant" Sized particles mixed with fracturing fluid to hold fractures open after a hydraulic fracturing treatment. In addition to naturally occurring sand grains, man-made or specially engineered proppants, such as resin-coated sand or high-strength ceramic materials like sintered bauxite, may also be used. Proppant materials are carefully sorted for size and sphericity to provide an efficient conduit for production of fluid from the reservoir to the wellbore.

"Proved developed producing" Proved developed reserves that can be expected to be recovered from a reservoir that is currently producing through existing wells.

"Proved developed reserves" Proved natural gas, oil and NGLs that are also developed natural gas, oil and NGL reserves.

"Proved natural gas, oil and NGL reserves" Proved natural gas, oil and NGL reserves are those quantities of natural gas, oil and NGLs that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. Also referred to as "proved reserves." For additional information, see the SEC's definition in Rule 4-10(a) (22) of Regulation S-X, a link for which is available at the SEC's website.

"Proved reserves" See "proved natural gas, oil and NGL reserves."

"Proved undeveloped reserves" or "PUD" Proved natural gas, oil and NGL reserves that are also undeveloped natural gas, oil and NGL reserves.

"PV-10" When used with respect to natural gas, oil and NGL reserves, PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs in effect as of the date of the report or estimate, without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%. Also referred to as "present value." After-tax PV-10 is also referred to as "standardized measure" and is net of future income tax expense.

"Reserve life index" The quotient resulting from dividing total reserves by annual production and typically expressed in years.

"Reserve replacement ratio" The sum of the estimated net proved reserves added through discoveries, extensions, infill drilling and acquisitions (which may include or exclude reserve revisions of previous estimates) for a specified period of time divided by production for that same period of time.

"Reservoir" A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs. For additional information, see the SEC's definition in Rule 4-10(a) (27) of Regulation S-X, a link for which is available at the SEC's website.

"Royalty interest" An interest in a natural gas and oil property entitling the owner to a share of natural gas, oil or NGL production free of production costs.

"Tcfe" One trillion cubic feet of natural gas equivalent, with liquids converted to an equivalent volume of natural gas using the ratio of one barrel of oil to six Mcf of natural gas.

"Unconventional play" A play in which the targeted reservoirs generally fall into one of three categories: tight sands, coal beds, or shales. The reservoirs tend to cover large areas and lack the readily apparent traps, seals and discrete hydrocarbon-water boundaries that typically define conventional reservoirs. These reservoirs generally require fracture stimulation treatments or other special recovery processes in order to produce economic flow rates.

"Undeveloped acreage" Those leased acres on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or gas regardless of whether such acreage contains proved reserves. For additional information, see the SEC's definition in Item 1208(c)(4) of Regulation S-K, a link for which is available at the SEC's website.

"Undeveloped natural gas, oil and NGL reserves" Undeveloped natural gas, oil and NGL reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Also referred to as "undeveloped reserves." For additional information, see the SEC's definition in Rule 4-10(a) (31) of Regulation S-X, a link for which is available at the SEC's website.

"Undeveloped reserves" See "undeveloped natural gas, oil and NGL reserves."

"Wells to sales" Wells that have been placed on sales for the first time.

"Working interest" An operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and to receive a share of production.

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

"WTI" West Texas Intermediate, the benchmark oil price in the United States.

ITEM 1A. RISK FACTORS

You should carefully consider the following risk factors in addition to the other information included in this Annual Report. Each of these risk factors could adversely affect our business, operating results and financial condition, as well as adversely affect the value of an investment in our common stock.

Risks Related to Our Business

Natural gas, oil and NGL prices greatly affect our revenues and thus profits, liquidity, growth, ability to repay our debt and the value of our assets.

Our revenues, profitability, liquidity, growth, ability to repay our debt and the value of our assets greatly depend on prices for natural gas, oil and NGLs. The markets for these commodities are volatile, and we expect that volatility to continue. The prices of natural gas, oil and NGLs fluctuate in response to changes in supply and demand (global, regional and local), transportation costs, market uncertainty and other factors that are beyond our control. Short- and long-term prices are subject to a myriad of factors such as:

- overall demand, including the relative cost of competing sources of energy or fuel;
- overall supply, including costs of production;
- the availability, proximity and capacity of pipelines, other transportation facilities and gathering, processing and storage facilities;
- regional basis differentials;
- national and worldwide economic and political conditions;
- weather conditions and seasonal trends;
- government regulations, such as regulation of natural gas transportation and price controls;
- inventory levels; and
- market perceptions of future prices, whether due to the foregoing factors or others.

For example, in 2020 and 2019, the NYMEX settlement price for natural gas ranged from a low of $1.50 per MMBtu in July 2020 to a high of $3.64 per MMBtu in January 2019, and during this period our production was 79% and 78% natural gas, respectively. NGLs represent a growing part of our business, and in the same period settlement prices for ethane and propane, our two principal NGL products, ranged from $5.25 per Bbl in March 2020 to $13.00 per Bbl in February 2019 and $12.32 per Bbl in March 2020 to $28.22 per Bbl in February 2019, respectively. Although we hedge a large portion of our production against changing prices, derivatives do not protect all our future volumes, may result in our forgoing profit opportunities if markets rise and, for NGLs, are not always available for substantial periods into the future. In 2020, we received $362 million, net of amounts we paid, in settlement of hedging arrangements. Moreover, when market expectations of future prices fall, as they did in 2020, the prices at which we can hedge are lower, reducing future revenue.

Lower natural gas, oil and NGL prices directly reduce our revenues and thus our operating income and cash flow. Lower prices also reduce the projected profitability of further drilling and therefore are likely to reduce our drilling activity, which in turn means we will have fewer wells on production in the future. Lower prices also reduce the value of our assets, both by a direct reduction in what the production would be worth and by making some properties uneconomic, resulting in non-cash impairments to the recorded value of our reserves and non-cash charges to earnings. For example, in 2020, we reported non-cash impairment charges on our natural gas and oil properties totaling $2,825 million, primarily resulting from decreases in trailing 12-month average first-day-of-the-month natural gas prices throughout 2020, as compared to 2019, and the non-cash impairment of certain undeveloped leasehold interests. Further non-cash impairments in future periods could occur if the trailing 12-month commodity prices decrease as compared to the average used in prior periods.

As of December 31, 2020, we had $3.2 billion of debt outstanding, consisting principally of senior notes maturing in various increments from 2022 to 2028, and $700 million of borrowings under our revolving credit facility, which matures in 2024. At current commodity price levels, our net cash flow from operations is substantially higher than our interest obligations under this debt, but significant drops in realized prices could affect our ability to pay our current obligations or refinance our debt as it becomes due.

Moreover, general industry conditions may make it difficult or costly to refinance increments of this debt as it matures. Although our indentures do not contain significant covenants restricting our operations and other activities, our bank credit agreements contain financial covenants with which we must comply. We refer you to the risk factor “Our current and future levels of indebtedness may adversely affect our results and limit our growth.” Our inability to pay our current obligations or refinance our debt as it becomes due could have a material and adverse effect on our company. The drop in prices since 2014 has reduced our revenues, profits and cash flow, caused us to record significant non-cash asset impairments and led us to reduce both our level of capital investing and our workforce, which has caused us to incur significant expenses relating to employee terminations. Further price decreases could have similar consequences. Similarly, a rise in prices to levels experienced before 2015 could significantly increase our revenues, profits and cash flow, which could be used to expand capital investments.

Significant capital investment is required to replace our reserves and conduct our business.

Our activities require substantial capital investment, not only to expand revenues but also because production from existing wells and thus revenues declines each year. We intend to fund our future capital investing through net cash flows from operations, net of changes in working capital. Our ability to generate operating cash flow is subject to many of the risks and uncertainties that exist in our industry, some of which we may not be able to anticipate at this time. Future cash flows from operations are subject to a number of risks and variables, such as the level of production from existing wells, prices of natural gas, oil and NGLs, our success in developing and producing new reserves and the other risk factors discussed herein. If we are unable to fund capital investing, we could experience a further reduction in drilling new wells, acquiring new acreage and a loss of existing leased acreage, resulting in a decline in our cash flow from operations and natural gas, oil and NGL production and reserves.

If we are not able to replace reserves, our production levels and thus our revenues and profits may decline.

Production levels from existing wells decline over time, and drilling new wells requires an inventory of leases and other rights with reserves that have not yet been drilled. Our future success depends largely upon our ability to find, develop or acquire additional natural gas, oil and NGL reserves that are economically recoverable. Unless we replace the reserves we produce through successful development, acquisition or exploration activities, our proved reserves and production will decline over time. Identifying and exploiting new reserves requires significant capital investment and successful drilling operations. Thus, our future natural gas, oil and NGL reserves and production, and therefore our revenues and profits, are highly dependent on our level of capital investments, our success in efficiently developing our current reserves and economically finding or acquiring additional recoverable reserves.

Our business depends on access to natural gas, oil and NGL transportation systems and facilities. Our commitments to assure availability of transportation could lead to substantial payments for capacity we do not use if production falls below projected levels.

The marketability of our natural gas, oil and NGL production depends in large part on the operation, availability, proximity, capacity and expansion of transportation systems and facilities owned by third parties. For example, we can provide no assurance that sufficient transportation capacity will exist for expected production from Appalachia or that we will be able to obtain sufficient transportation capacity on economic terms. During the past few years, several planned pipelines intended to service production in the Northeast United States have experienced delays in their in-service dates due to regulatory delays and litigation.

Producers compete by lowering their sales prices, resulting in the locational differences from NYMEX pricing. Further, a lack of available capacity on transportation systems and facilities or delays in their planned expansions could result in the shut-in of producing wells or the delay or discontinuance of drilling plans for properties. A lack of availability of these systems and facilities for an extended period of time could negatively affect our revenues. In addition, we have entered into contracts for firm transportation and any failure to renew those contracts on the same or better commercial terms could increase our costs and our exposure to the risks described above.

We have entered into gathering agreements in producing areas and multiple long-term firm transportation agreements relating to natural gas volumes from all our producing areas. As of December 31, 2020, our aggregate demand charge commitments under these firm transportation agreements and gathering agreements were approximately $8.5 billion. If our development programs fail to produce sufficient quantities of natural gas and ethane to fill the contracted capacity within expected timeframes, we would be required to pay demand or other charges for transportation on pipelines and gathering systems for capacity that we would not be fully utilizing. In those situations, which have occurred on a small scale at various times, we endeavor to sell or transfer that capacity to others or fill the excess capacity with production purchased from third parties. There can be no assurance that these measures will recoup the full cost of the unused transportation.

Strategic determinations, including the allocation of capital and other resources to strategic opportunities, are challenging in the face of shifting market conditions, and our failure to appropriately allocate capital and resources among our strategic opportunities may adversely affect our financial condition and reduce our future growth rate.

We necessarily must consider future price and cost environments when deciding how much capital we are likely to have available from net cash flow and how best to allocate it. Our current philosophy is to generally operate within cash flow from operations, net of changes in working capital, and to invest capital in a portfolio of projects that are projected to generate the highest combined Internal Rate of Return. Volatility in prices and potential errors in estimating costs, reserves or timing of production of the reserves can result in uneconomic projects or economic projects generating less than anticipated returns.

Certain of our undeveloped assets are subject to leases that will expire over the next several years unless production is established on units containing the acreage.

Approximately 19,242 and 68,825 net acres of our Northeast Appalachia and Southwest Appalachia acreage, respectively, will expire in the next three years if we do not drill successful wells to develop the acreage or otherwise take action to extend the leases. Our ability to drill wells depends on a number of factors, including certain factors that are beyond our control, such as the ability to obtain permits on a timely basis or to compel landowners or lease holders on adjacent properties to cooperate. Further, we may not have sufficient capital to drill all the wells necessary to hold the acreage without increasing our debt levels, or given price projections at the time, drilling may not be projected to achieve a sufficient return or be judged to be the best use of our capital. To the extent we do not drill the wells, our rights to acreage can be lost.

Natural gas and oil drilling and producing and transportation operations can be hazardous and may expose us to liabilities.

Drilling and production operations are subject to many risks, including well blowouts, cratering and explosions, pipe failures, fires, formations with abnormal pressures, uncontrollable flows of oil, natural gas, brine or well fluids, severe weather, natural disasters, groundwater contamination and other environmental hazards and risks. Some of these risks or hazards could materially and adversely affect our revenues and expenses by reducing or shutting in production from wells, loss of equipment or otherwise negatively impacting the projected economic performance of our prospects. If any of these risks occurs, we could sustain substantial losses as a result of:

- injury or loss of life;
- severe damage to or destruction of property, natural resources or equipment;
- pollution or other environmental damage;
- clean-up responsibilities;
- regulatory investigations and administrative, civil and criminal penalties; and
- injunctions resulting in limitation or suspension of operations.

For our properties that we do not operate, we depend on the operator for operational and regulatory compliance.

We rely on third parties to transport our production to markets. Their operations, and thus our ability to reach markets, are subject to all of the risks and operational hazards inherent in transporting natural gas and ethane and natural gas compression, including:

- damages to pipelines, facilities and surrounding properties caused by third parties, severe weather, natural disasters, including hurricanes, and acts of terrorism;
- maintenance, repairs, mechanical or structural failures;
- damages to, loss of availability of and delays in gaining access to interconnecting third-party pipelines;
- disruption or failure of information technology systems and network infrastructure due to various causes, including unauthorized access or attack; and
- leaks of natural gas or ethane as a result of the malfunction of equipment or facilities.

A material event such as those described above could expose us to liabilities, monetary penalties or interruptions in our business operations. Although we may maintain insurance against some, but not all, of the risks described above, our insurance may not be adequate to cover casualty losses or liabilities, and our insurance does not cover penalties or fines that may be assessed by a governmental authority. Also, in the future we may not be able to obtain insurance at premium levels that justify its purchase.

We have made significant investments in oilfield service businesses, including our drilling rigs, water infrastructure and pressure pumping equipment, to lower costs and secure inputs for our operations and transportation for our production. If our development and production activities are curtailed or disrupted, we may not recover our investment in these activities, which could adversely impact our results of operations. In addition, our continued expansion of these operations may adversely impact our relationships with third-party providers.

We also have made investments to meet certain of our field services' needs, including establishing our own drilling rig operation, water transportation system in Southwest Appalachia and pressure pumping capability. If our level of operations is reduced for a long period, we may not be able to recover these investments. Further, our presence in these service and supply sectors, including competing with them for qualified personnel and supplies, may have an adverse effect on our relationships with our existing third-party service and resource providers or our ability to secure these services and resources from other providers.

Our business depends on the availability of water and the ability to dispose of water. Limitations or restrictions on our ability to obtain or dispose of water may have an adverse effect on our financial condition, results of operations and cash flows.

Water is an essential component of drilling and hydraulic fracturing processes. Limitations or restrictions on our ability to secure sufficient amounts of water, or to dispose of or recycle water after use, could adversely impact our operations. In some cases, water may need to be obtained from new sources and transported to drilling sites, resulting in increased costs. Moreover, the introduction of new environmental initiatives and regulations related to water acquisition or waste water disposal, including produced water, drilling fluids and other wastes associated with the exploration, development or production of hydrocarbons, could limit or prohibit our ability to utilize hydraulic fracturing or waste water injection control wells.

In addition, concerns have been raised about the potential for seismic activity to occur from the use of underground injection control wells, a predominant method for disposing of waste water from oil and gas activities. New rules and regulations may be developed to address these concerns, possibly limiting or eliminating the ability to use disposal wells in certain locations and increasing the cost of disposal in others. We utilize third parties to dispose of waste water associated with our operations. These third parties may operate injection wells and may be subject to regulatory restrictions relating to seismicity.

Compliance with environmental regulations and permit requirements governing the withdrawal, storage and use of water necessary for hydraulic fracturing of wells or the disposal of water may increase our operating costs or may cause us to delay, curtail or discontinue our exploration and development plans, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our producing properties are concentrated in the Appalachian basin, making us vulnerable to risks associated with operating in limited geographic areas.

Our producing properties currently are geographically concentrated in the Appalachian basin in Pennsylvania, West Virginia and Ohio. At December 31, 2020, nearly 100% of our total estimated proved reserves were attributable to properties located in the Appalachian basin. As a result of this concentration in one primary region, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, state and local politics, processing or transportation capacity constraints, market limitations, availability of equipment and personnel, water shortages or interruption of the processing or transportation of natural gas, oil or NGLs.

Competition in the oil and natural gas industry is intense, making it more difficult for us to market natural gas, oil and NGLs, to secure trained personnel and appropriate services, to obtain additional properties and to raise capital.

Our cost of operations is highly dependent on third-party services, and competition for these services can be significant, especially in times when commodity prices are rising. Similarly, we compete for trained, qualified personnel, and in times of lower prices for the commodities we produce, we and other companies with similar production profiles may not be able to attract and retain this talent. Our ability to acquire and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing natural gas, oil and NGLs and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil and gas industry. Certain of our competitors may possess and employ financial, technical and personnel resources greater than ours. Those companies may be able to pay more for personnel, property and services and to attract capital at lower rates. This may become more likely if prices for oil and NGLs increase faster than prices for natural gas, as natural gas comprises a greater percentage of our overall production than it does for most of the companies with whom we compete for talent.

We may be unable to dispose of assets on attractive terms, and may be required to retain liabilities for certain matters.

Various factors could materially affect our ability to dispose of assets if and when we decide to do so, including the availability of purchasers willing to purchase the assets at prices acceptable to us, particularly in times of reduced and volatile commodity prices. Sellers typically retain liabilities for certain matters. The magnitude of any such retained liability or indemnification obligation may be difficult to quantify at the time of the transaction and ultimately may be material. Also, as is typical in divestiture transactions, third parties may be unwilling to release us from guarantees or other credit support provided prior to the sale of the divested assets. As a result, after a sale, we may remain secondarily liable for the obligations guaranteed or supported to the extent that the buyer of the assets fails to perform these obligations.

Certain U.S. federal income tax deductions currently available with respect to oil and natural gas exploration and production may be eliminated as a result of future legislation.

The elimination of certain key U.S. federal income tax deductions currently available to oil and natural gas exploration and production companies may be proposed in the future. These changes may include, among other proposals:

- repeal of the percentage depletion allowance for natural gas and oil properties;
- elimination of current deductions for intangible drilling and development costs; and
- extension of the amortization period for certain geological and geophysical expenditures.

The passage of these or any similar changes in U.S. federal income tax laws to eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development could have an adverse effect on our financial position, results of operations and cash flows.

In March 2020, the Coronavirus Aid, Relief, and Economic Security Act ("CARES" Act) was introduced to stabilize the economy during the coronavirus pandemic. The CARES Act temporarily suspends and modifies certain tax laws established by the 2017 tax reform law known as the Tax Cuts and Jobs Act, including, but not limited to, modifications to net operating loss limitations, business interest limitations and alternative minimum tax.

We may experience adverse or unforeseen tax consequences due to further developments affecting our deferred tax assets that could significantly affect our results.

Deferred tax assets, including net operating loss carryforwards, represent future savings of taxes that would otherwise be paid in cash. At December 31, 2020, we had substantial amounts of net operating loss carryforwards for U.S. federal and state income tax purposes. Our ability to utilize the deferred tax assets is dependent on the amount of future pre-tax income that we are able to generate through our operations or sale of assets. If management concludes that it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized, a valuation allowance will be recognized in the period that this conclusion is reached. In addition, limitations may exist upon use of these carryforwards in the event that a change in control of the Company occurs.

A cyber incident could result in information theft, data corruption, operational disruption and/or financial loss.

Our business has become increasingly dependent on digital technologies to conduct day-to-day operations, including certain exploration, development and production activities as well as processing of revenues and payments. We depend on digital technology, including information systems and related infrastructure as well as cloud applications and services, to process and record financial and operating data, analyze seismic and drilling information, conduct reservoir modeling and reserves estimation, communicate with employees and business associates, perform compliance reporting and in many other activities related to our business. Our vendors, service providers, purchasers of our production 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. Our technologies, systems, networks, and those of our business associates may become the target of cyber-attacks or information security breaches, which could lead to disruptions in critical systems, unauthorized release of confidential or protected information, corruption of data or other disruptions of our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period.

A cyber-attack involving our information systems and related infrastructure, or that of companies with which we deal, could disrupt our business and negatively impact our operations in a variety of ways, including:

- unauthorized access to seismic data, reserves information, strategic information or other sensitive or proprietary information could have a negative impact on our ability to compete for natural gas and oil resources;
- unauthorized access to personal identifying information of property lessors, working interest partners, employees and vendors, which could expose us to allegations that we did not sufficiently protect that information;
- data corruption or operational disruption of production infrastructure could result in loss of production, or accidental discharge;
- a cyber-attack on a vendor or service provider could result in supply chain disruptions, which could delay or halt our major development projects; and
- a cyber-attack on a third party gathering, pipeline or rail service provider could delay or prevent us from marketing our production, resulting in a loss of revenues.

These events could damage our reputation and lead to financial losses from remedial actions, loss of business or potential liability, which could have a material adverse effect on our financial condition, results of operations or cash flows.

To date we have not experienced any material losses or interruptions relating to cyber-attacks; however, there can be no assurance that we will not suffer such losses in the future. 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.

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

Terrorist attacks and the threat of terrorist attacks, whether domestic or foreign attacks, as well as military or other actions taken in response to these acts, could cause instability in the global financial and energy markets. Continued hostilities in the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy in unpredictable ways, including the disruption of energy supplies and markets, increased volatility in commodity prices or the possibility that the infrastructure on which we rely could be a direct target or an indirect casualty of an act of terrorism, and, in turn, could materially and adversely affect our business and results of operations.

The widespread outbreak of an illness, pandemic (such as COVID-19) or any other public health crisis may have material adverse effects on our financial position, results of operations or cash flows.

In December 2019, COVID-19 was reported to have surfaced in China. The spread of this virus has caused business disruptions beginning in January 2020, including disruptions in the oil and natural gas industry. In March 2020, the World Health Organization declared the outbreak of COVID-19 to be a pandemic, and the U.S. economy began to experience pronounced effects. The COVID-19 pandemic has negatively impacted the global economy, disrupted global supply chains, reduced global demand for oil and gas, and created significant volatility and disruption of financial and commodity markets. The extent of the impact of the COVID-19 pandemic on our operational and financial performance, including our ability to execute our business strategies and initiatives in the expected time frame, is uncertain and depends on various factors, including the demand for natural gas, oil, NGLs and other products derived from these commodities, the availability of personnel, equipment and services critical to our ability to operate our properties and the impact of potential governmental restrictions on travel, transports and operations. There is uncertainty around the extent and duration of the disruption. The degree to which the COVID-19 pandemic or any other public health crisis adversely impacts our results will depend on future developments, which are highly uncertain and cannot be predicted, including, but not limited to, the duration and spread of the outbreak, its severity, the actions to contain the virus or treat its impact, its impact on the economy and market conditions, and how quickly and to what extent normal economic and operating conditions can resume. Therefore, while the Company expects this matter will likely continue to impact its operations, the degree of the adverse financial impact cannot be reasonably estimated at this time.

Negative public perception regarding us and/or our industry could have an adverse effect on our operations.

Negative public perception regarding us and/or our industry resulting from, among other things, concerns raised by advocacy groups about climate change, emissions, hydraulic fracturing, seismicity, oil spills and explosions of transmission lines, may lead to regulatory scrutiny, which may, in turn, lead to new state and federal safety and environmental laws, regulations, guidelines and enforcement interpretations. These actions may cause operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risk of litigation. Moreover, governmental authorities exercise considerable discretion in the timing and scope of permit issuance and the public may engage in the permitting process, including through intervention in the courts. Negative public perception could cause the permits we need to conduct our operations to be withheld, delayed, or burdened by requirements that restrict our ability to profitably conduct our business. In addition, various officials and candidates at the federal, state and local levels, including some presidential candidates, have proposed banning hydraulic fracturing altogether.

Judicial decisions can affect our rights and obligations.

Our ability to develop gas, oil and NGLs depends on the leases and other mineral rights we acquire and the rights of owners of nearby properties. We operate in areas where judicial decisions have not yet definitively interpreted various contractual provisions or addressed relevant aspects of property rights, nuisance and other matters that could be the source of claims against us as a developer or operator of properties. Although we plan our activities according to our expectations of these unresolved areas, based on decisions on similar issues in these jurisdictions and decisions from courts in other states that have addressed them, courts could resolve issues in ways that increase our liabilities or otherwise restrict or add costs to our operations.

Common stockholders will be diluted if additional shares are issued.

We endeavor to create value for our stockholders on a per share basis. From time to time we have issued stock to raise capital for our business, including significant offerings of new shares in 2015, 2016 and 2020. We also issue restricted stock, options and performance share units to our employees and directors as part of their compensation. In addition, we may issue additional shares of common stock, additional notes or other securities or debt convertible into common stock, to extend maturities or fund capital expenditures. If we issue additional shares of our common stock in the future, it may have a dilutive effect on our current outstanding stockholders.

Anti-takeover provisions in our organizational documents and under Delaware law may impede or discourage a takeover, which could cause the market price of our common stock to decline.

We are a Delaware corporation, and the anti-takeover provisions of Delaware law impose various impediments to the ability of a third party to acquire control of us, even if a change in control would be beneficial to our existing stockholders, which, under certain circumstances, could reduce the market price of our common stock. In addition, protective provisions in our Amended and Restated Certificate of Incorporation and Amended and Restated Bylaws or the implementation by our Board of Directors of a stockholder rights plan that could deter a takeover.

Risks Related to our Indebtedness and Financing Abilities

A downgrade in our credit rating could negatively impact our cost of and ability to access capital and our liquidity.

Actual or anticipated changes or downgrades in our credit ratings, including any announcement that our ratings are under review for a downgrade, could impact our ability to access debt markets in the future to refinance existing debt or obtain additional funds, affect the market value of our senior notes and increase our borrowing costs. Such ratings are limited in scope, and do not address all material risks relating to us, but rather reflect only the view of each rating agency of the likelihood we will be able to repay our debt at the time the rating is issued. An explanation of the significance of each rating may be obtained from the applicable rating agency. As of February 25, 2021, our long-term issuer ratings were Ba2 by Moody's, BB- by Standard and Poor's and BB by Fitch Investor Services. There can be no assurance that such credit ratings will remain in effect for any given period of time or that such ratings will not be lowered, suspended or withdrawn entirely by the rating agencies, if, in each rating agency's judgment, circumstances so warrant.

Actual downgrades in our credit ratings may also impact our interest costs and liquidity. The interest rates under certain of our senior notes increases as credit ratings fall. Many of our existing commercial contracts contain, and future commercial contracts may contain, provisions permitting the counterparty to require increased security upon the occurrence of a downgrade in our credit rating. Providing additional security, such as posting letters of credit, could reduce our available cash or our liquidity under our revolving credit facility for other purposes. We had $233 million of letters of credit outstanding at December 31, 2020. The amount of additional financial assurance would depend on the severity of the downgrade from the credit rating agencies, and a downgrade could result in a decrease in our liquidity.

Our current and future levels of indebtedness may adversely affect our results and limit our growth.

At December 31, 2020, we had long-term indebtedness of $3.2 billion. The terms of the indentures governing our outstanding senior notes, our credit facilities, and the lease agreements relating to our drilling rigs, other equipment and headquarters building, which we collectively refer to as our "financing agreements," impose restrictions on our ability and, in some cases, the ability of our subsidiaries to take a number of actions that we may otherwise desire to take, which may include, without limitation, one or more of the following:

- incurring additional debt;
- redeeming stock or redeeming certain debt;
- making certain investments;
- creating liens on our assets; and
- selling assets.

The revolving credit facility we entered into in April 2018, as amended (our "2018 credit facility"), contains customary representations, warranties and covenants including, among others, the following covenants:

- a prohibition against incurring debt, subject to permitted exceptions;
- a restriction on creating liens on assets, subject to permitted exceptions;
- restrictions on mergers and asset dispositions;
- restrictions on use of proceeds, investments, transactions with affiliates, or change of principal business; and
- maintenance of the following financial covenants, commencing with the fiscal quarter ended June 30, 2018:
    1. Minimum current ratio of no less than 1.00 to 1.00, whereby current ratio is defined as the Company's consolidated current assets (including unused commitments under the credit agreement, but excluding non-cash derivative assets) to consolidated current liabilities (excluding non-cash derivative obligations and current maturities of long-term debt).
    2. Maximum total net leverage ratio of no greater than 4.00 to 1.00 subsequent to June 30, 2020. Total net leverage ratio is defined as total debt less cash on hand (up to the lesser of 10% of credit limit or $150 million) divided by consolidated EBITDAX for the last four consecutive quarters. For purposes of calculating consolidated EBITDAX, the Company can include the Montage consolidated EBITDAX prior to the merger for the same rolling twelve-month period. EBITDAX, as defined in our revolving credit facility, excludes the effects of interest expense, depreciation, depletion and amortization, income tax, any non-cash impacts from impairments, certain non-cash hedging activities, stock-based compensation expense, non-cash gains or losses on asset sales, unamortized issuance cost, unamortized debt discount and certain restructuring costs.

In conjunction with the October 2020 redetermination process, the Company entered into an amendment to the credit agreement governing the 2018 credit facility to, among other matters:

- limit the Company's unrestricted cash and cash equivalents to $200 million when loans under the 2018 credit facility are outstanding, subject to certain exceptions; and
- increase the applicable rate by 25 basis points on loans outstanding under the 2018 credit facility.

As of December 31, 2020, we were in compliance with all of the covenants of our revolving credit facility in all material respects. Our ability to comply with these financial covenants depends in part on the success of our development program and upon factors beyond our control, such as the market prices for natural gas, oil and NGLs.

Our level of indebtedness and off-balance sheet obligations, and the covenants contained in our financing agreements, could have important consequences for our operations, including:

- requiring us to dedicate a substantial portion of our cash flow from operations to required payments, thereby reducing the availability of cash flow for working capital, capital investing and other general business activities;
- limiting our ability to obtain additional financing in the future for working capital, capital investing, acquisitions and general corporate and other activities;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and
- detracting from our ability to successfully withstand a downturn in our business or the economy generally.

Any significant reduction in the borrowing base under our revolving credit facility may negatively impact our ability to fund our operations, and we may not have sufficient funds to repay borrowings under our revolving credit facility if required as a result of a borrowing base redetermination.

The amount we may borrow under our revolving credit facility is capped at the lower of the total of our bank commitments and a "borrowing base" determined from time to time by the lenders based on our reserves, market conditions and other factors. As of December 31, 2020, the borrowing base and total aggregate commitments were $2.0 billion, which was most recently reaffirmed as of November 2020. The borrowing base is subject to scheduled semiannual and other elective collateral borrowing base redeterminations based on our natural gas, oil and NGL reserves and other factors. As of December 31, 2020, we had $700 million of outstanding borrowings under our revolving credit facility, and we expect to borrow under that facility in the future. As of December 31, 2020, we had $233 million of letters of credit issued under the credit facility and unused borrowing capacity was approximately $1.1 billion which exceeds our currently modeled needs. Any significant reduction in our borrowing base as a result of borrowing base redeterminations or otherwise may negatively impact our liquidity and our ability to fund our operations and, as a result, may have a material adverse effect on our financial position, results of operation and cash flow. Further, if the outstanding borrowings under our revolving credit facility were to exceed the borrowing base as a result of any such redetermination or other reasons, we would be required to repay the excess within a brief period. We may not have sufficient funds to make such repayments. If we do not have sufficient funds and we are otherwise unable to negotiate renewals of our borrowings or arrange new financing, we may have to sell significant assets. Any such sale could have a material adverse effect on our business and financial results.

Our ability to comply with the covenants and other restrictions in our financing agreements may be affected by events beyond our control, including prevailing economic and financial conditions.

Failure to comply with the covenants and other restrictions could lead to an event of default and the acceleration of our obligations under our senior notes, credit facilities or other financing agreements, and in the case of the lease agreements for drilling rigs, compressors and pressure pumping equipment, loss of use of the equipment. In particular, the occurrence of risks identified elsewhere in this section, such as declines in commodity prices, increases in basis differentials and inability to access markets, could reduce our profits and thus the cash we have to fulfill our financial obligations. If we are unable to satisfy our obligations with cash on hand, we could attempt to refinance such debt, sell assets or repay such debt with the proceeds from an equity offering. We cannot assure that we will be able to generate sufficient cash flow to pay the interest on our debt, to meet our lease obligations, or that future borrowings, equity financings or proceeds from the sale of assets will be available to pay or refinance such debt or obligations. The terms of our financing agreements may also prohibit us from taking such actions. Factors that will affect our ability to raise cash through an offering of our capital stock, a refinancing of our debt or a sale of assets include financial market conditions and our market value and operating performance at the time of such offering or other financing. We cannot assure that any such proposed offering, refinancing or sale of assets can be successfully completed or, if completed, that the terms will be favorable to us.

Risks Related to Governmental Regulation

Climate change legislation or regulations governing the emissions of greenhouse gases could result in increased operating costs and reduce demand for the natural gas, oil and NGLs we produce, and concern in financial and investment markets over greenhouse gasses and fossil fuel production could adversely affect our access to capital and the price of our common stock.

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to human health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, establish Prevention of Significant Deterioration, or PSD, construction and Title V operating permit reviews for certain large stationary sources. Facilities required to obtain PSD permits for their greenhouse gas emissions also will be required to meet "best available control technology" standards that will be established on a case-by-case basis. EPA rulemakings related to greenhouse gas emissions could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources.

The EPA also has adopted rules requiring the monitoring and reporting of greenhouse gas emissions from specified onshore and offshore natural gas and oil production sources in the United States on an annual basis, which include certain of our operations. In May 2016, the EPA finalized additional regulations to control methane and volatile organic compound emissions from certain oil and gas equipment and operations. However, in September 2020, the EPA finalized further amendments to the standards that removed the transmission and storage segments from the oil and natural gas source category and rescinded the methane-specific requirements for production and processing facilities. Several lawsuits were filed challenging these amendments, and the U.S. Court of Appeals for the D.C. Circuit ordered an administrative stay of these amendments shortly after they were finalized. Although the administrative stay was lifted in October 2020, which brought the amendments into effect, the amendments may be subject to reversal under a new presidential administration.

Although Congress from time to time has considered legislation to reduce emissions of greenhouse gases, there has not been significant activity in the form of adopted legislation to reduce greenhouse gas emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of states, including states in which we operate, have enacted or passed measures to track and reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and regional greenhouse gas cap-and-trade programs. Most of these cap-and-trade programs require major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall greenhouse gas emission reduction goal is achieved. These reductions may cause the cost of allowances to escalate significantly over time.

The adoption and implementation of regulations that require reporting of greenhouse gases or otherwise limit emissions of greenhouse gases from our equipment and operations could require us to incur costs to monitor and report on greenhouse gas emissions or install new equipment to reduce emissions of greenhouse gases associated with our operations. In addition, these regulatory initiatives could drive down demand for our products by stimulating demand for alternative forms of energy that do not rely on combustion of fossil fuels that serve as a major source of greenhouse gas emissions, which could have a material adverse effect on our business, financial condition, results of operations and cash flows. At the same time, new laws and regulations are prompting power producers to shift from coal to natural gas, which is increasing demand.

In December 2015, over 190 countries, including the United States, reached an agreement to reduce global greenhouse gas emissions (the "Paris Agreement"). The Paris Agreement entered into force in November 2016 after more than 70 nations, including the United States, ratified or otherwise indicated their intent to be bound by the agreement. In November 2019, the United States formally initiated the process for withdrawing from the Paris Agreement, which resulted in an effective exit date of November 2020. However, in January 2021, the new administration announced that the United States intends to rejoin the Paris Agreement. To the extent that the United States and other countries implement this agreement or impose other climate change regulations on the oil and natural gas industry, or that investors insist on compliance regardless of legal requirements, it could have an adverse effect on our business.

We, our service providers and our customers are subject to complex federal, state and local laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities.

Our development and production operations and the transportation of our products to market are subject to complex and stringent federal, state and local laws and regulations, including those governing environmental protection, the occupational health and safety aspects of our operations, the discharge of materials into the environment, and the protection of certain plant and animal species. See "Other – Environmental Regulation" in Item 1 of Part I of this Annual Report for a description of the laws and regulations that affect us. These laws and regulations require us, our service providers and our customers to obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. Environmental regulations may restrict the types, quantities and concentration of materials that may be released into the environment in connection with drilling and production activities, limit or prohibit drilling or transportation activities on certain lands lying within wilderness, wetlands, archeological sites and other protected areas, and impose substantial liabilities for pollution resulting from our operations and those of our service providers and customers. Moreover, we or they may experience delays in obtaining or be unable to obtain required permits, including as a result of government shutdowns, which may delay or interrupt our or their operations and limit our growth and revenues. In addition, various officials and candidates at the federal, state and local levels, including some presidential candidates, have proposed banning hydraulic fracturing altogether.

Failure to comply with laws and regulations can trigger a variety of administrative, civil and criminal enforcement measures, including investigatory actions, the assessment of monetary penalties, the imposition of remedial requirements, or the issuance of orders or judgments limiting or enjoining future operations. Strict liability or joint and several liability may be imposed under certain laws, which could cause us to become liable for the conduct of others or for consequences of our own actions. Moreover, our costs of compliance with existing laws could be substantial and may increase or unforeseen liabilities could be imposed if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. If we are not able to recover the increased costs through insurance or increased revenues, our business, financial condition, results of operations and cash flows could be adversely affected.

Risks Related to Financial Markets and Uncertainties

Market views of our industry generally can affect our stock price.

Factors described elsewhere, including views regarding future commodity prices, regulation and climate change, can affect the amount investors choose to invest in our industry generally. Recent years have seen a significant reduction in overall investment in exploration and production companies, resulting in a drop in individual companies' stock prices. Separate from actual and possible governmental action, certain financial institutions have announced policies to cease investing or to divest investments in companies, such as ours, that produce fossil fuels, and some banks have announced they no longer will lend to companies in this sector. To date these represent small fractions of overall sources of equity and debt, but that fraction could grow and thus affect our access to capital. Moreover, some equity investors are expressing concern over these matters and may prompt companies in our industry to adopt more costly practices even absent governmental action. Although we believe our practices result in low emission rates for methane and other greenhouse gases as compared to others in our industry, complying with investor sentiment may require modifications to our practices, which could increase our capital and operating expenses.

Volatility in the financial markets or in global economic factors could adversely impact our business and financial condition.

Our business may be negatively impacted by adverse economic conditions or future disruptions in global financial markets. Included among these potential negative impacts are reduced energy demand and lower commodity prices, including due to the possible impact of the coronavirus (COVID-19), increased difficulty in collecting amounts owed to us by our customers, reduced access to credit markets and the risks related to the discontinuation of LIBOR and other reference rates, including increased expenses and litigation and the effectiveness of interest rate hedge strategies. Our ability to access the capital markets may be restricted at a time when we would like, or need, to raise financing. If financing is not available when needed, or is available only on unfavorable terms, we may be unable to implement our business plans or otherwise take advantage of business opportunities or respond to competitive pressures.

Any changes in U.S. trade policy could trigger retaliatory actions by affected countries, resulting in “trade wars,” in increased costs for materials necessary for our industry along with other goods imported into the United States, which may reduce customer demand for these products if the parties having to pay those tariffs increase their prices, or in trading partners limiting their trade with the United States. If these consequences are realized, the volume of economic activity in the United States, including growth in sectors that utilize our products, may be materially reduced along with a reduction in the potential export of our products. Such a reduction may materially and adversely affect commodity prices, our sales and our business.

Risks Related to the Ability of our Hedging Activities to Adequately Manage our Exposure to Commodity and Financial Risk

Our proved natural gas, oil and NGL reserves are estimates that include uncertainties. Any material changes to these uncertainties or underlying assumptions could cause the quantities and net present value of our reserves to be overstated or understated.

As described in more detail under “Critical Accounting Policies and Estimates – Natural Gas and Oil Properties” in Item 7 of Part II of this Annual Report, our reserve data represents the estimates of our reservoir engineers made under the supervision of our management, and our reserve estimates are audited each year by Netherland, Sewell & Associates, Inc., or NSAI, an independent petroleum engineering firm. Reserve engineering is a subjective process of estimating underground accumulations of natural gas, oil and NGLs that cannot be measured in an exact manner. The process of estimating quantities of proved reserves is complex and inherently imprecise, and the reserve data included in this document are only estimates. The process relies on interpretations of available geologic, geophysical, engineering and production data. The extent, quality and reliability of this technical data can vary. The process also requires certain economic assumptions, some of which are mandated by the SEC, such as using historic natural gas, oil and NGL prices rather than future projections. Additional assumptions include drilling and operating expenses, capital investing, taxes and availability of funds. Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same data.

Results of drilling, testing and production subsequent to the date of an estimate may justify revising the original estimate. Accordingly, initial reserve estimates often vary from the quantities of natural gas, oil and NGLs that are ultimately recovered, and such variances may be material. Any significant variance could reduce the estimated quantities and present value of our reserves.

You should not assume that the present value of future net cash flows from our proved reserves is the current market value of our estimated natural gas, oil and NGL reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on the preceding 12-month average natural gas, oil and NGL index prices, calculated as the unweighted arithmetic average for the first day of the month price for each month and costs in effect on the date of the estimate, holding the prices and costs constant throughout the life of the properties. Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than the current estimate. In addition, the 10% discount factor we use when calculating discounted future net cash flows for reporting requirements in compliance with the applicable accounting standards 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 gas industry in general.

Our commodity price risk management and measurement systems and economic hedging activities might not be effective and could increase the volatility of our results.

We currently seek to hedge the price of a significant portion of our estimated production through swaps, collars, floors and other derivative instruments. The systems we use to quantify commodity price risk associated with our businesses might not always be effective. Further, such systems do not in themselves manage risk, particularly risks outside of our control, and adverse changes in energy commodity market prices, volatility, adverse correlation of commodity prices, the liquidity of markets, changes in interest rates and other risks discussed in this report might still adversely affect our earnings, cash flows and balance sheet under applicable accounting rules, even if risks have been identified. Furthermore, no single hedging arrangement can adequately address all risks present in a given contract. For example, a forward contract that would be effective in hedging commodity price volatility risks would not hedge the contract's counterparty credit or performance risk. Therefore, unhedged risks will always continue to exist.

Our use of derivatives, through which we attempt to reduce the economic risk of our participation in commodity markets could result in increased volatility of our reported results. Changes in the fair values (gains and losses) of derivatives that qualify as hedges under GAAP to the extent that such hedges are not fully effective in offsetting changes to the value of the hedged commodity, as well as changes in the fair value of derivatives that do not qualify or have not been designated as hedges under GAAP, must be recorded in our income. This creates the risk of volatility in earnings even if no economic impact to us has occurred during the applicable period. To the extent we cap or lock prices at specific levels, we would also forgo the ability to realize the higher revenues that would be realized should prices increase.

The impact of changes in market prices for natural gas, oil and NGLs on the average prices paid or received by us may be reduced based on the level of our hedging activities. These hedging arrangements may limit or enhance our margins if the market prices for oil, natural gas or NGLs were to change substantially from the price established by the hedges. In addition, our hedging arrangements expose us to the risk of financial loss if our production volumes are less than expected.

The implementation of derivatives legislation could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The Dodd-Frank Act established federal oversight and regulation of the over-the-counter derivatives market and entities, including us, which participate in that market. The Dodd-Frank Act requires the CFTC, the SEC, and other regulatory authorities to promulgate rules and regulations implementing the Dodd-Frank Act. Although the CFTC has finalized most of its regulations under the Dodd-Frank Act, it continues to review and refine its initial rulemakings through additional interpretations and supplemental rulemakings. As a result, it is not possible at this time to predict the ultimate effect of the rules and regulations on our business and while most of the regulations have been adopted, any new regulations or modifications to existing regulations may increase the cost of derivative contracts, limit the availability of derivatives to protect against risks that we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and the regulations thereunder, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital investing.

In January 2020, the CFTC proposed new amended regulations that would place federal limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. In 2016, the CFTC finalized a companion rule on aggregation of positions among entities under common ownership or control. If finalized, the position limits rule may have an impact on our ability to hedge our exposure to certain enumerated commodities.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and mandatory trading on designated contract markets or swap execution facilities. The CFTC may designate additional classes of swaps as subject to the mandatory clearing requirement in the future, but has not yet proposed rules designating any other classes of swaps, including physical commodity swaps, for mandatory clearing. The CFTC and prudential banking regulators also adopted mandatory margin requirements on uncleared swaps between swap dealers and certain other counterparties. The margin requirements are currently effective with respect to certain market participants and will be phased in over time with respect to other market participants, based on the level of an entity's swaps activity. We expect to qualify for and rely upon an end-user exception from the mandatory clearing and trade execution requirements for swaps entered to hedge our commercial risks. We also should qualify for an exception from the uncleared swaps margin requirements. However, the application of the mandatory clearing and trade execution requirements and the uncleared swaps margin requirement to other market participants, such as swap dealers, may adversely affect the cost and availability of the swaps that we use for hedging.

Risks Related to the Merger

Southwestern may not achieve the anticipated benefits of the Merger, and the Merger may disrupt its current plans or operations.

The success of the Merger will depend, in part, on Southwestern's ability to realize the anticipated benefits and cost savings from combining Southwestern's and Montage's businesses, and there can be no assurance that Southwestern and Montage will be able to successfully integrate or otherwise realize the anticipated benefits of the Merger. Difficulties in integrating Southwestern and Montage may result in the combined company performing differently than expected, in operational challenges, or in the failure to realize anticipated expense-related efficiencies. Potential difficulties that may be encountered in the integration process include, among others:

- the inability to successfully integrate Montage in a manner that permits the achievement of full revenue, expected cash flows and cost savings anticipated from the Merger;
- not realizing anticipated operating synergies;
- integrating personnel from the two companies and the loss of key employees;
- potential unknown liabilities and unforeseen expenses or delays associated with and following the completion of the Merger;
- integrating relationships with customers, vendors and business partners;
- performance shortfalls as a result of the diversion of management's attention caused by completing the Merger and integrating Montage's operations; and
- the disruption of, or the loss of momentum in, Southwestern's ongoing business or inconsistencies in standards, controls, procedures and policies.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES

The summary of our oil and natural gas reserves as of fiscal year-end 2020 based on average fiscal-year prices, as required by Item 1202 of Regulation S-K, is included in the table headed "2020 Proved Reserves by Category and Summary Operating Data" in "Business – Exploration and Production – Our Proved Reserves" in Item 1 of this Annual Report and incorporated by reference into this Item 2.

The information regarding our proved undeveloped reserves required by Item 1203 of Regulation S-K is included under the heading "Proved Undeveloped Reserves" in "Business – Exploration and Production – Our Proved Reserves" in Item 1 of this Annual Report.

The information regarding delivery commitments required by Item 1207 of Regulation S-K is included under the heading "Sales, Delivery Commitments and Customers" in the "Business – Exploration and Production – Our Operations" in Item 1 of this Annual Report and incorporated by reference into this Item 2. For additional information about our natural gas and oil operations, we refer you to "Supplemental Oil and Gas Disclosures" in Item 8 of Part II of this Annual Report. For information concerning capital investments, we refer you to "Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Capital Investing." We also refer you to Item 6, "Selected Financial Data" in Part II of this Annual Report for information concerning natural gas, oil and NGLs produced.

The information regarding natural gas and oil properties, wells, operations and acreage required by Item 1208 of Regulation S-K is set forth below:

Leasehold acreage as of December 31, 2020

	Undeveloped		Developed		Total	
	Gross	Net	Gross	Net	Gross	Net
Northeast Appalachia	107,465	89,086	134,449	128,210	241,914	217,296
Southwest Appalachia	610,969	425,702	186,390	146,220	797,359	571,922
Other:						
US – Other Exploration	9,652	6,329	5,034	2,263	14,686	8,592
US – Sand Wash Basin	5,898	3,435	14,977	9,974	20,875	13,409
Total US	733,984	524,552	340,850	286,667	1,074,834	811,219
Canada – New Brunswick (1)	2,518,519	2,518,519	—	—	2,518,519	2,518,519
	3,252,503	3,043,071	340,850	286,667	3,593,353	3,329,738

(1) The exploration licenses for 2,518,519 net acres in New Brunswick, Canada, have been subject to a moratorium since 2015. These licenses expire in March 2021, and we fully impaired our investment in New Brunswick in 2016. We are currently working with Canadian officials to extend our licenses, although we cannot assure that the licenses will be extended past March 2021.

Lease Expirations

The following table summarizes the leasehold acreage expiring over the next three years, assuming successful wells are not drilled to develop the acreage and leases are not extended:

	For the years ended December 31,		
Net acreage expiring:	2021	2022	2023
Northeast Appalachia	5,861	6,460	6,921
Southwest Appalachia (1)	36,690	20,149	11,986
Other:			
US – Other Exploration	5,683	646	—
US – Sand Wash Basin	3,435	—	—
Canada – New Brunswick (2)	2,518,519	—	—

(1) The leasehold acreage expiring includes 8,907 acres acquired through the Montage Merger that are subject to annual extension options at our sole discretion. Excluding this acreage, of the remaining leasehold acreage expiring, 17,460 net acres in 2021, 6,173 net acres in 2022 and 5,573 net acres in 2023 can be extended for an average 4.9 years.

(2) Exploration licenses were extended through March 2021 but have been subject to a moratorium since 2015. We are currently working with Canadian officials to extend our licenses, although we cannot assure that the licenses will be extended past March 2021. We impaired their value to $0 in 2016.

Producing wells as of December 31, 2020

	Natural Gas		Oil		Total		Gross Wells Operated
	Gross	Net	Gross	Net	Gross	Net	
Northeast Appalachia	744	668	—	—	744	668	677
Southwest Appalachia	1,796	1,487	37	34	1,833	1,521	1,670
Other	8	5	6	6	14	11	14
	2,548	2,160	43	40	2,591	2,200	2,361

The information regarding drilling and other exploratory and development activities required by Item 1205 of Regulation S-K is set forth below:

	Exploratory					
	Productive Wells		Dry Wells		Total	
Year	Gross	Net	Gross	Net	Gross	Net
2020						
Northeast Appalachia	—	—	—	—	—	—
Southwest Appalachia	—	—	—	—	—	—
Other	—	—	—	—	—	—
Total	—	—	—	—	—	—
2019						
Northeast Appalachia	—	—	—	—	—	—
Southwest Appalachia	—	—	—	—	—	—
Other	—	—	—	—	—	—
Total	—	—	—	—	—	—
2018						
Northeast Appalachia	—	—	—	—	—	—
Southwest Appalachia	—	—	—	—	—	—
Fayetteville Shale [(1)]	—	—	—	—	—	—
Other	—	—	—	—	—	—
Total	—	—	—	—	—	—

(1) The Fayetteville Shale E&P assets were sold in December 2018.

	Development					
	Productive Wells		Dry Wells		Total	
Year	Gross	Net	Gross	Net	Gross	Net
2020						
Northeast Appalachia	45.0	44.4	—	—	45.0	44.4
Southwest Appalachia	55.0	44.6	—	—	55.0	44.6
Total	100.0	89.0	—	—	100.0	89.0
2019						
Northeast Appalachia	44.0	41.7	—	—	44.0	41.7
Southwest Appalachia	69.0	53.5	—	—	69.0	53.5
Total	113.0	95.2	—	—	113.0	95.2
2018						
Northeast Appalachia	60.0	59.5	—	—	60.0	59.5
Southwest Appalachia	76.0	59.3	—	—	76.0	59.3
Fayetteville Shale [(1)]	2.0	1.8	—	—	2.0	1.8
Total	138.0	120.6	—	—	138.0	120.6

(1) The Fayetteville Shale E&P assets were sold in December 2018.

The following table presents the information regarding our present activities required by Item 1206 of Regulation S-K:

Wells in progress as of December 31, 2020

	Gross	Net
Drilling:		
Northeast Appalachia	16.0	15.6
Southwest Appalachia	14.0	13.6
Total	30.0	29.2
Completing:		
Northeast Appalachia	10.0	10.0
Southwest Appalachia	2.0	1.8
Total	12.0	11.8
Drilling & Completing:		
Northeast Appalachia	26.0	25.6
Southwest Appalachia	16.0	15.4
Total	42.0	41.0

The information regarding oil and gas production, production prices and production costs required by Item 1204 of Regulation S-K is set forth below:

Production, Average Sales Price and Average Production Cost

	For the years ended December 31,		
	2020	2019	2018
Natural Gas			
Production *(Bcf)*:			
Northeast Appalachia	473	459	459
Southwest Appalachia	221	150	105
Fayetteville Shale (1)	—	—	243
Total	694	609	807
Average realized gas price, excluding derivatives *($/Mcf)*:			
Northeast Appalachia	$ 1.37	$ 2.10	$ 2.54
Southwest Appalachia	$ 1.27	$ 1.62	$ 2.58
Fayetteville Shale (1)	$ —	$ —	$ 2.21
Total	$ 1.34	$ 1.98	$ 2.45
Average realized gas price, including derivatives *($/Mcf)*:	$ 1.70	$ 2.18	$ 2.35
Oil			
Production *(MBbls)*:			
Southwest Appalachia	5,124	4,673	3,355
Other	17	23	52
Total	5,141	4,696	3,407
Average realized oil price, excluding derivatives *($/Bbl)*:			
Southwest Appalachia	$ 29.18	$ 46.86	$ 56.71
Other	$ 37.24	$ 53.66	$ 62.01
Total	$ 29.20	$ 46.90	$ 56.79
Average realized oil price, including derivatives *($/Bbl)*:	$ 46.91	$ 49.56	$ 56.07
NGL			
Production *(MBbls)*:			
Southwest Appalachia	25,923	23,611	19,679
Other	4	9	27
Total	25,927	23,620	19,706
Average realized NGL price, excluding derivatives *($/Bbl)*:			
Southwest Appalachia	$ 10.24	$ 11.59	$ 17.89
Other	$ 11.50	$ 7.61	$ 28.12
Total	$ 10.24	$ 11.59	$ 17.91
Average realized NGL price, including derivatives *($/Bbl)*	$ 11.15	$ 13.64	$ 17.23
Total Production *(Bcfe)*			
Northeast Appalachia	473	459	459
Southwest Appalachia	407	319	243
Fayetteville Shale (1)	—	—	243
Other	—	—	1
Total (2)	880	778	946
Lease Operating Expense			
Cost per Mcfe, excluding ad valorem and severance taxes:			
Northeast Appalachia	$ 0.86	$ 0.85	$ 0.81
Southwest Appalachia	$ 1.00	$ 1.02	$ 1.08
Fayetteville Shale (1)	$ —	$ —	$ 0.98
Total	$ 0.93	$ 0.92	$ 0.93

(1) The Fayetteville Shale E&P assets and associated reserves were sold in December 2018.

(2) Approximately 878 Bcfe, 776 Bcfe and 698 Bcfe for the years ended December 31, 2020, 2019 and 2018, respectively, were produced from the Marcellus Shale formation. Approximately 243 Bcfe for the year ended December 31, 2018 was produced from the Fayetteville Shale.

During 2020, we were required to file Form 23, "Annual Survey of Domestic Oil and Gas Reserves," with the U.S. Department of Energy. The basis for reporting reserves on Form 23 is not comparable to the reserve data included in "Supplemental Oil and Gas Disclosures" in Item 8 of Part II of this Annual Report. The primary differences are that Form 23 reports gross reserves, including the royalty owners' share, and includes reserves for only those properties of which we are the operator.

Title to Properties

We believe that we have satisfactory title to substantially all of our active properties in accordance with standards generally accepted in the oil and natural gas industry. Our properties are subject to customary royalty and overriding royalty interests, certain contracts relating to the exploration, development, operation and marketing of production from such properties, consents to assignment and preferential purchase rights, liens for current taxes, applicable laws and other burdens, encumbrances and irregularities in title, which we believe do not materially interfere with the use of or affect the value of such properties. Prior to acquiring undeveloped properties, we endeavor to perform a title investigation that is thorough but less vigorous than that we endeavor to conduct prior to drilling, which is consistent with standard practice in the oil and natural gas industry. Generally, before we commence drilling operations on properties that we operate, we conduct a title examination and perform curative work with respect to significant defects that we identify. We believe that we have performed title review with respect to substantially all of our active properties that we operate.

ITEM 3. LEGAL PROCEEDINGS

We are subject to various litigation, claims and proceedings that arise in the ordinary course of business, such as for alleged breaches of contract, miscalculation of royalties, employment matters, traffic incidents, pollution, contamination, encroachment on others' property or nuisance. We accrue for such items when a liability is both probable and the amount can be reasonably estimated. It is not possible at this time to estimate the amount of any additional loss, or range of loss that is reasonably possible, but based on the nature of the claims, management believes that current litigation, claims and proceedings, individually or in aggregate and after taking into account insurance, are not likely to have a material adverse impact on our financial position, results of operations or cash flows, for the period in which the effect of that outcome becomes reasonably estimable. Many of these matters are in early stages, so the allegations and the damage theories have not been fully developed, and are all subject to inherent uncertainties; therefore, management's view may change in the future. If an unfavorable final outcome were to occur, there exists the possibility of a material impact on our financial position, results of operations or cash flows for the period in which the effect becomes reasonably estimable.

We are also subject to laws and regulations relating to the protection of the environment. Environmental and cleanup related costs of a non-capital nature are accrued when it is both probable that a liability has been incurred and when the amount can be reasonably estimated. Management believes any future remediation or other compliance related costs will not have a material effect on our financial position or results of operations.

See "Litigation" in Note 10 to the consolidated financial statements included in this Annual Report for further details on our current legal proceedings.

ITEM 4. MINE SAFETY DISCLOSURES

Our sand mining facility in Arkansas, which previously supported our Fayetteville Shale operations, is subject to regulation by the Federal Mine Safety and Health Administration under the Federal Mine Safety and Health Act of 1977. 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 95.1 to this Annual Report.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is traded on the New York Stock Exchange (the "NYSE") under the symbol "SWN." On February 25, 2021, the closing price of our common stock trading under the symbol "SWN" was $4.22 and we had 2,269 stockholders of record.

We currently do not pay dividends on our common stock, and we do not anticipate paying any cash dividends in the foreseeable future. All decisions regarding the declaration and payment of dividends and stock repurchases are at the discretion of our Board of Directors and will be evaluated regularly in light of our financial condition, earnings, growth prospects, funding requirements, applicable law and any other factors that our Board of Directors deems relevant.

Information required by Item 5 of Part II with respect to equity compensation plans will be included under the caption Equity Compensation Plans in our Proxy Statement relating to our 2021 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before May 18, 2021, and is incorporated herein by reference.

Issuer Purchases of Equity Securities

The table below sets forth information with respect to purchases of our common stock made by us or on our behalf during the quarter ended December 31, 2020:

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
October 2020	—	$ —	n/a	n/a
November 2020	—	$ —	n/a	n/a
December 2020	9,961	$ 3.02	n/a	n/a
Total fourth-quarter 2020:	9,961	$ 3.02	n/a	

(1) Reflects shares retired by us to satisfy applicable tax withholding obligations due on employee stock plan share issuances.

Recent Sales of Unregistered Equity Securities

We did not sell any unregistered equity securities during 2020.

ITEM 6. SELECTED FINANCIAL DATA

None.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Management's Discussion and Analysis is the Company's analysis of its financial performance and of significant trends that may affect future performance. It should be read in conjunction with the financial statements and notes, and supplemental oil and gas disclosures included elsewhere in this report. It contains forward-looking statements including, without limitation, statements relating to the Company's plans, strategies, objectives, expectations and intentions that are made pursuant to the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. In many cases you can identify forward-looking statements by words such as "anticipate," "intend," "plan," "project," "estimate," "continue," "potential," "should," "could," "may," "will," "objective," "guidance," "outlook," "effort," "expect," "believe," "predict," "budget," "projection," "goal," "forecast," "target" or similar words. Unless required to do so under the federal securities laws, the Company does not undertake to update, revise or correct any forward-looking statements, whether as a result of new information, future events or otherwise. Readers are cautioned that such forward-looking statements should be read in conjunction with the Company's disclosures under the heading: "Cautionary Statement about Forward-Looking Statements."

OVERVIEW

Background

Southwestern Energy Company (including its subsidiaries, collectively, "we," "our," "us," "the Company" or "Southwestern") is an independent energy company engaged in natural gas, oil and NGLs exploration, development and production, which we refer to as "E&P." We are also focused on creating and capturing additional value through our marketing business, which we call "Marketing". We conduct most of our businesses through subsidiaries, and we currently operate exclusively in the lower 48 United States.

E&P. Our primary business is the exploration for and production of natural gas, oil and NGLs, with our ongoing operations focused on the development of unconventional natural gas reservoirs located in Pennsylvania, Ohio and West Virginia. Our operations in northeast Pennsylvania, which we refer to as "Northeast Appalachia," are primarily focused on the unconventional natural gas reservoir known as the Marcellus Shale. Our operations in West Virginia, Ohio and southwest Pennsylvania, which we refer to as "Southwest Appalachia," are focused on the Marcellus Shale, the Utica and the Upper Devonian unconventional natural gas and oil reservoirs. Collectively, our properties in Pennsylvania, Ohio and West Virginia are herein referred to as "Appalachia." We also have drilling rigs located in Appalachia, and we provide certain oilfield products and services, principally serving our E&P operations though vertical integration.

On November 13, 2020, we closed on our Agreement and Plan of Merger (the "Merger agreement") with Montage Resources Corporation ("Montage") pursuant to which Montage merged with and into Southwestern, with Southwestern continuing as the surviving company (the "Merger"). The Merger expanded our footprint in Appalachia by supplementing our Northeast Appalachia and Southwest Appalachia operations and by expanding our operations into Ohio. See Note 3 to the consolidated financial statements of this Annual Report for more information on the Merger.

Marketing. Our marketing activities capture opportunities that arise through the marketing and transportation of natural gas, oil, and NGLs primarily produced in our E&P operations.

Focus in 2020. We entered 2020 with a continued focus on optimizing our cost structure, maximizing margins in each of our core areas of business while further developing our knowledge of our asset base and looking for strategic transactions that take advantage of our core strengths. The recent Merger and the associated expected cost and operational synergies is a reflection of this strategy. While COVID-19 brought challenges of lower demand for certain of our products resulting in lower oil and NGL pricing (discussed below), we exercised our capital and operational agility by quickly shifting our investments to our higher return natural gas assets. We remained committed to our focus on creating sustainable value with the goal of generating cash flow above and beyond our operational needs, while at the same time maintaining our leading position as stewards of the environment. We continued to protect our financial strength through bond repurchases at a discount as well as a robust derivative program designed to ensure certain cash flow levels by reducing our exposure to commodity price volatility.

Lower natural gas, oil and NGL prices present challenges to our industry and our Company, as do changes in laws, regulations and investor sentiment and other key factors described under "Risk Factors" in Item 1A of this Annual Report. During the year ended December 31, 2020, the economic impact of the COVID-19 pandemic and related governmental and societal measures (discussed below), along with the disagreements between OPEC and Russia on production levels, caused oil prices to decrease significantly in the first and second quarters of 2020. While oil pricing partially recovered late in the second quarter and continued to improve toward the end of the year, gains on our settled derivatives offset a large portion of the impact of the overall decline in prices. Although we currently expect to maintain a robust rolling three-year derivative portfolio, there can be no assurance that we will be able to add derivative positions to cover our expected production at favorable prices. See "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A and Note 6 - Derivatives and Risk Management, in the consolidated financial statements included in this Annual Report for further details.

Market Conditions and Commodity Prices

During 2020, we did not experience any material impact to our ability to operate or market our production due to the direct or indirect impacts of the COVID-19 pandemic. In early March 2020, we instituted additional health measures at our facilities and banned nonessential travel. In mid-March, in advance of state and local governments restricting business operations and imposing "stay-at-home" directives in Pennsylvania, West Virginia and Texas (where our operations and offices are located), we notified employees that those whose work does not require a physical presence should work from home. In late September 2020, based on the totality of the relevant data in each community, we reinstituted a phased return program of office-based employees, and we have instituted additional measures designed to prevent the possible spread of the virus, including social distancing and appropriate personal protective equipment. The U.S. Department of Homeland Security classifies individuals engaged in and supporting exploration for and production of natural gas, oil and NGLs as "essential critical infrastructure workforce," and to date, state and local governments have followed this guidance and exempted these activities from business closures. Should this situation change, our access to supplies or workers to drill, complete and operate wells could be materially and adversely affected.

Beginning late in the first quarter and extending through most of 2020, decreased transportation, manufacturing and general economic activity levels prompted by governmental and societal actions to COVID-19 reduced the demand for refined products such as gasoline, distillate and jet fuel and other refined products, as well as NGLs. Reduced demand, along with geopolitical events such as the disagreements between OPEC and Russia on production levels, caused a significant decline in oil and NGL pricing late in the first quarter of 2020. Although WTI prices for oil were 31% lower in 2020, as compared to 2019, our average realized price received for oil, including the impact of our derivatives, was only 5% lower in 2020, compared to the previous year. We recognized an additional $0.36 per Mcf on our gas production through our derivative program for the year ended December 31, 2020, an increase of $0.16 per Mcf over the prior year, which partially offset a $0.55 decrease in the NYMEX price over the same period.

Late in the second quarter of 2020 and extending into the fourth quarter of 2020, certain states and local governments began the process of loosening restrictions, allowing businesses to reopen and lifting stay-at-home orders. In addition, OPEC and other countries instituted oil production curtailments. During this same period, oil and NGL prices have improved from historic lows in April due to lower industry-wide production levels and increased export demand, respectively. Further, although the reduced production of natural gas associated with oil wells dampened the effect of lower natural gas demand early in the second quarter, high natural gas storage inventories and lower LNG demand for U.S. cargoes led to a natural gas price decline late in the second quarter. During the third quarter of 2020, as more clarity emerged regarding the projected path for European natural gas storage, global LNG prices rallied substantially and signaled a resumption of U.S. LNG exports beginning in late September 2020. In addition, the recovery of U.S. natural gas production was less robust than most market estimates, which kept storage balances below capacity through the end of the injection season in October 2020. As a result of these events, the demand and related pricing for natural gas have improved from earlier in the year, and we continue to mitigate pricing risk for all of our commodities through our proactive derivative program.

The degree to which the COVID-19 pandemic or any other public health crisis adversely impacts our results will depend on future developments, which are uncertain and cannot be predicted, including, but not limited to, the duration and spread of the outbreak, its severity, the effectiveness of the vaccines and the actions to contain the virus or treat its impact, its impact on the economy and market conditions, and how quickly and to what extent normal economic and operating conditions can resume. We will continually monitor our 2021 capital investment program to take into account these changed conditions and proactively adjust our activities and plans. Therefore, while this continued matter could potentially disrupt our operations, the degree of the potentially adverse financial impact cannot be reasonably estimated at this time.

Recent Financial and Operating Results

Significant operating and financial highlights for 2020 include:

Total Company

- Completion of the Merger with Montage on November 13, 2020, acquiring approximately 1,375 producing wells and approximately 320,000 net acres.
- Completion of a public offering of 63,250,000 shares of common stock at $2.50 per share with net proceeds of approximately $152 million after underwriting discounts and offering expenses.
- Closed an offering of $350 million aggregate principal amount of 8.375% senior notes due 2028 with net proceeds of $345 million after underwriting discounts and offering expenses.
- Net loss of $3,112 million, or ($5.42) per diluted share, was down from a net income of $891 million, or $1.65 per diluted share, in 2019. The decrease in 2020 was primarily due to $2,825 million of non-cash full cost ceiling test impairments, an $818 million change in deferred tax provision and lower margins associated with reduced commodity prices.
- Operating loss was $2,871 million for the year ended December 31, 2020, compared to an operating income of $270 million in 2019, primarily due to a $2,825 million non-cash full cost ceiling test impairment in 2020. Excluding the non-cash impairment, operating loss of $46 million decreased $316 million as increased natural gas and liquids production, lower depreciation, depletion and amortization and general and administrative expense were more than offset by reduced commodity prices along with merger-related expenses.
- Net cash provided by operating activities of $528 million decreased 45% from $964 million in 2019 as an improvement in settled derivatives and the impact of higher production was more than offset by lower commodity prices and an increase in operating expenses associated with higher liquids production, along with decreases in capitalized interest expense and working capital.
- Total capital invested of $899 million decreased 21% from $1,140 million in 2019.

E&P

- E&P segment operating loss was $2,864 million in 2020, compared to an operating income of $283 million in 2019. The decrease in 2020 was primarily due to non-cash full cost ceiling impairments of $2,825 million in 2020 and reduced commodity prices.
- Year-end reserves of 11,990 Bcfe decreased 731 Bcfe, or 6%, from 12,721 Bcfe at the end of 2019, as 2,354 Bcfe of acquired reserves, 1,424 Bcfe of positive performance revisions and 741 Bcfe of additions were more than offset by 4,370 Bcfe of downward price revisions and 880 Bcfe of production.
- Total net production of 880 Bcfe, which was comprised of 79% natural gas, 17% NGLs and 4% oil, increased 13% from 778 in 2019, and our liquids production increased 10% over the same period.
- Excluding the effect of derivatives, our realized natural gas price of $1.34 per Mcf, realized oil price of $29.20 per barrel and realized NGL price of $10.24 per barrel decreased 32%, 38% and 12%, respectively, from 2019. Our weighted average realized price excluding the effect of derivatives of $1.53 per Mcfe decreased 30% from the same period in 2019.
- The E&P segment invested $899 million in capital; drilling 98 wells, completing 96 wells and placing 100 wells to sales.

Outlook

In 2021, we expect to continue to exercise capital discipline in our investment program by investing below cash flow from operations, net of changes in working capital, in a focused effort to generate free cash flow. In addition, we expect to continue maintaining our robust hedging program, looking for ways to optimize our cost structure and maximizing margins in each core area of our business while further developing our knowledge of our asset base. By carrying out these objectives, we expect to generate additional free cash flow, which we intend to use to further strengthen our balance sheet. We remain committed to our focus on optimizing our portfolio by concentrating our efforts on our highest return investment opportunities. We believe that we and our industry will continue to face challenges due to the uncertainty of natural gas, oil and NGL prices in the United States, changes in laws, regulations and investor sentiment, and other key factors described above under "Risk Factors."

RESULTS OF OPERATIONS

The following discussion of our results of operations for our segments is presented before intersegment eliminations. We evaluate our segments as if they were stand-alone operations and accordingly discuss their results prior to any intersegment eliminations. Interest expense, gain (loss) on derivatives, gain (loss) on early extinguishment of debt and income taxes are discussed on a consolidated basis.

We have applied the Securities and Exchange Commission's recently adopted FAST Act Modernization and Simplification of Regulation S-K, which limits the discussion to the two most recent fiscal years. This discussion and analysis deals with comparisons of material changes in the consolidated financial statements for fiscal 2020 and fiscal 2019. For the comparison of fiscal 2019 and fiscal 2018, see "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Part II, Item 7 of our 2019 Annual Report on Form 10-K, filed with the Securities and Exchange Commission on February 27, 2020.

E&P

(in millions)	For the years ended December 31, 2020		For the years ended December 31, 2019	
Revenues	$ 1,348	(1)	$ 1,703	(2)
Operating costs and expenses	4,212	(3)	1,420	(4)
Operating income (loss)	$ (2,864)		$ 283	
Gain on derivatives, settled (5)	$ 362		$ 180	

(1) Includes $5 million related to gas balancing for the year ended December 31, 2020.

(2) Includes $2 million in third-party water sales for the year ended December 31, 2019.

(3) Includes $2,825 million of non-cash full-cost ceiling test impairments, $41 million in Montage merger-related expenses, $16 million of restructuring charges and $5 million of non-cash, non-full cost pool impairments for the year ended December 31, 2020.

(4) Includes $11 million of restructuring charges and $13 million of non-cash, non-full cost pool asset impairments for the year ended December 31, 2019.

(5) Includes $11 million and $1 million amortization of premiums paid related to certain natural gas settled derivatives for the years ended December 31, 2020 and 2019, respectively.

Operating Income

- E&P segment operating loss for the year ended December 31, 2020 was $2,864 million compared to an operating income of $283 million for the year ended December 31, 2019. Excluding $2,825 million of non-cash full cost ceiling test impairments recorded in 2020, our E&P segment operating loss was $39 million for the year ended December 31, 2020. This decrease is primarily due to lower margins associated with decreased commodity pricing.

Revenues

The following illustrate the effects on sales revenues associated with changes in commodity prices and production volumes:

(in millions except percentages)	For the years ended December 31, Natural Gas	Oil	NGLs	Total
2019 sales revenues (1)	$ 1,207	$ 220	$ 274	$ 1,701
Changes associated with prices	(447)	(91)	(36)	(574)
Changes associated with production volumes	168	21	27	216
2020 sales revenues (2)	**$ 928**	**$ 150**	**$ 265**	**$ 1,343**
Decrease from 2019	(23)%	(32)%	(3)%	(21)%

(1) Excludes $2 million in other operating revenues for the year ended December 31, 2019 related to third-party water sales.

(2) Excludes $5 million in other operating revenues for the year ended December 31, 2020 related to gas balancing.

Production Volumes

	For the years ended December 31,		
	2020	2019	Increase/ (Decrease)
Natural Gas *(Bcf)*			
Northeast Appalachia	473	459	3%
Southwest Appalachia	221	150	47%
Other	—	—	—%
Total	694	609	14%
Oil *(MBbls)*			
Southwest Appalachia	5,124	4,673	10%
Other	17	23	(26)%
Total	5,141	4,696	9%
NGL *(MBbls)*			
Southwest Appalachia	25,923	23,611	10%
Other	4	9	(56)%
Total	25,927	23,620	10%
Production volumes by area *(Bcfe)***:**			
Northeast Appalachia	473	459	3%
Southwest Appalachia	407	319	28%
Other	—	—	—%
Total (1)	880	778	13%
Production percentage:			
Natural gas	79%	78%	
Oil	4%	4%	
NGL	17%	18%	

(1) Approximately 878 Bcfe and 776 Bcfe for the years ended December 31, 2020 and 2019, respectively, were produced from the Marcellus Shale formation.

- Production volumes for our E&P segment increased 102 Bcfe for the year ended December 31, 2020, compared to the same period in 2019, primarily due to a 28% increase in production volumes in Southwest Appalachia.
- Oil and NGL production increased 9% and 10%, respectively, for the year ended December 31, 2020, compared to 2019.

Commodity Prices

The price we expect to receive for our production is a critical factor in determining the capital investments we make to develop our properties. Commodity prices fluctuate due to a variety of factors we can neither control nor predict, including increased supplies of natural gas, oil or NGLs due to greater exploration and development activities, weather conditions, political and economic events such as the response to the COVID-19 pandemic, and competition from other energy sources. These factors impact supply and demand, which in turn determine the sales prices for our production. In addition to these factors, the prices we realize for our production are affected by our hedging activities as well as locational differences in market prices, including basis differentials. We will continue to evaluate the commodity price environments and adjust the pace of our activity in order to maintain appropriate liquidity and financial flexibility.

	For the years ended December 31,		
	2020	2019	Increase/ (Decrease)
Natural Gas Price:			
NYMEX Henry Hub Price *($/MMBtu)* [1]	$ 2.08	$ 2.63	(21)%
Discount to NYMEX [2]	(0.74)	(0.65)	14%
Average realized gas price, excluding derivatives *($/Mcf)*	$ 1.34	$ 1.98	(32)%
Gain on settled financial basis derivatives *($/Mcf)*	0.11	—	
Gain on settled commodity derivatives *($/Mcf)*	0.25	0.20	
Average realized gas price, including derivatives *($/Mcf)*	$ 1.70	$ 2.18	(22)%
Oil Price:			
WTI oil price *($/Bbl)*	$ 39.40	$ 57.03	(31)%
Discount to WTI	(10.20)	(10.13)	1%
Average oil price, excluding derivatives *($/Bbl)*	$ 29.20	$ 46.90	(38)%
Gain on settled derivatives *($/Bbl)*	17.71	2.66	
Average oil price, including derivatives *($/Bbl)*	$ 46.91	$ 49.56	(5)%
NGL Price:			
Average realized NGL price, excluding derivatives *($/Bbl)*	$ 10.24	$ 11.59	(12)%
Gain on settled derivatives *($/Bbl)*	0.91	2.05	
Average realized NGL price, including derivatives *($/Bbl)*	$ 11.15	$ 13.64	(18)%
Percentage of WTI, excluding derivatives	26%	20%	
Total Weighted Average Realized Price:			
Excluding derivatives *($/Mcfe)*	$ 1.53	$ 2.18	(30)%
Including derivatives *($/Mcfe)*	$ 1.94	$ 2.42	(20)%

(1) Based on last day settlement prices from monthly futures contracts.

(2) This discount includes a basis differential, a heating content adjustment, physical basis sales, third-party transportation charges and fuel charges, and excludes financial basis hedges.

We receive a sales price for our natural gas at a discount to average monthly NYMEX settlement prices based on heating content of the gas, locational basis differentials and transportation and fuel charges. Additionally, we receive a sales price for our oil and NGLs at a difference to average monthly West Texas Intermediate settlement and Mont Belvieu NGL composite prices, respectively, due to a number of factors including product quality, composition and types of NGLs sold, locational basis differentials and transportation and fuel charges.

We regularly enter into various derivatives and other financial arrangements with respect to a portion of our projected natural gas, oil and NGL production in order to ensure certain desired levels of cash flow and to minimize the impact of price fluctuations, including fluctuations in locational market differentials. We refer you to Item 7A, Quantitative and Qualitative Disclosures about Market Risk, of this Annual Report, Note 6 to the consolidated financial statements included in this Annual Report, and our derivative risk factor for additional discussion about our derivatives and risk management activities.

The table below presents the amount of our future production in which the impact of basis volatility has been limited as of December 31, 2020:

	Volume *(Bcf)*	Basis Differential
Basis Swaps – Natural Gas		
2021	219	$ (0.21)
2022	139	(0.33)
2023	47	(0.45)
2024	11	(0.60)
2025	4	(0.59)
Total	420	
Physical NYMEX Sales Arrangements – Natural Gas		
2021	217	$ (0.24)
2022	65	(0.35)
2023	40	(0.37)
2024	18	(0.47)
2025	12	(0.50)
Total	352	

In addition to protecting basis, the table below presents the amount of our future production in which price is financially protected as of December 31, 2020:

	2021	2022	2023
Natural gas *(Bcf)*	751	378	87
Oil *(MBbls)*	6,631	2,155	878
Ethane *(MBbls)*	6,473	1,710	—
Propane *(MBbls)*	6,974	2,120	—
Normal butane *(MBbls)*	2,004	667	—
Natural gasoline *(MBbls)*	1,936	643	—
Total financial protection on future production *(Bcfe)*	895	422	92

We refer you to Note 6 of the consolidated financial statements included in this Annual Report for additional details about our derivative instruments.

Operating Costs and Expenses

	For the years ended December 31,		
(in millions except percentages)	2020	2019	Increase/ (Decrease)
Lease operating expenses	$ 815	$ 722	13%
General & administrative expenses	108 (1)	150 (2)	(28)%
Montage merger-related expenses	41	—	100%
Restructuring charges	16	11	45%
Taxes, other than income taxes	54	62	(13)%
Full cost pool amortization	333	439	(24)%
Non-full cost pool DD&A	15	23	(35)%
Impairments	2,830	13	(62)%
Total operating costs	$ 4,212	$ 1,420	197%

(1) Includes $1 million of legal settlement charges for the year ended December 31, 2020.

(2) Includes a $6 million residual value guarantee shortfall payment to the previous lessor of our headquarters building and $6 million of legal settlement charges for the year ended December 31, 2019.

Average unit costs per Mcfe:	For the years ended December 31, 2020	2019	Increase/ (Decrease)
Lease operating expenses [1]	$ 0.93	$ 0.92	1%
General & administrative expenses	$ 0.12 [2]	$ 0.18 [3]	(33)%
Taxes, other than income taxes	$ 0.06	$ 0.08	(25)%
Full cost pool amortization	$ 0.38	$ 0.56	(32)%

(1) Includes post-production costs such as gathering, processing, fractionation and compression.

(2) Excludes $41 million in Montage merger-related expenses $16 million in restructuring charges and $1 million in legal settlement charges for the year ended December 31, 2020.

(3) Excludes $11 million in restructuring charges, a $6 million residual value guarantee short-fall payment to the previous lessor of our headquarters building and $6 million of legal settlement charges for the year ended December 31, 2019.

Lease Operating Expenses

- Lease operating expenses per Mcfe increased $0.01 for the year ended December 31, 2020, compared to 2019, as an increase in liquids production, which includes processing fees, was only partially offset by a decrease related to temporarily reduced gathering and transportation rates in Southwest Appalachia that became effective late in the second quarter of 2020.

General and Administrative Expenses

- General and administrative expenses in 2020 included $1 million in legal settlement charges. 2019 included a $6 million residual value guarantee short-fall payment to the previous lessor of our headquarters building and $6 million in legal settlement charges. Excluding these amounts, general and administrative expenses decreased $31 million for the year ended December 31, 2020, compared to 2019, primarily due to decreased personnel costs and the implementation of cost reduction initiatives.

- On a per Mcfe basis, excluding restructuring, Montage merger-related expenses, legal settlement charges and the residual value guarantee short-fall payment, general and administrative expenses per Mcfe decreased by $0.06 for the year ended December 31, 2020, compared to 2019, due to a 28% decrease in expenses and a 13% increase in production volumes.

Montage Merger-Related Expenses

- Montage merger-related expenses for the year ended December 31, 2020 included $18 million in bank, legal and consulting fees; $17 million in employee severance and related costs; and $5 million related to the settlement of contracts inherited from Montage that had no future value to our ongoing business. We refer you to Note 3 of the consolidated financial statements included in this Annual Report for additional details about the Merger.

Restructuring Charges

- In February 2020, employees were notified of a workforce reduction plan as a result of a strategic realignment of our organizational structure. Affected employees were offered a severance package, which included a one-time cash payment depending on length of service and, if applicable, the current value of unvested long-term incentive awards that were forfeited. We also recognized additional severance costs in the fourth quarter of 2020 related to continued organizational restructuring. For the year ended December 31, 2020, we recognized a total restructuring expense of $16 million primarily related to cash severance, including payroll taxes.

- As of December 31, 2020, a $3 million liability for restructuring charges to be paid in 2021 has been recorded.

See Note 2 of the consolidated financial statements included in this Annual Report for additional details about our restructuring charges.

Taxes, Other than Income Taxes

- Taxes other than income taxes per Mcfe may vary from period to period due to changes in ad valorem and severance taxes that result from the mix of our production volumes and fluctuations in commodity prices. Taxes, other than income taxes, per Mcfe decreased $0.02 per Mcfe for the year ended December 31, 2020, compared to the same period in 2019, primarily due to lower commodity pricing and lower effective tax rates in Southwest Appalachia.

Full Cost Pool Amortization

- Our full cost pool amortization rate decreased $0.18 per Mcfe for the year ended December 31, 2020, as compared to 2019. The average amortization rate decreased primarily as a result of the impact of $2,825 million in non-cash full cost ceiling test impairments recorded in 2020.
- No impairment expense was recorded for the year ended December 31, 2020 in relation to our recently acquired Montage natural gas and oil properties. These properties were recorded at fair value as of November 13, 2020, in accordance with ASC 820 *Fair Value Measurement*. Pursuant to SEC guidance, we determined that the fair value of the properties acquired at the closing of the Merger clearly exceeded the related full-cost ceiling limitation beyond a reasonable doubt and received a waiver from the SEC to exclude the properties acquired in the Merger from the ceiling test calculation. This waiver was granted for all reporting periods through and including the quarter ending September 30, 2021 as long as we can continue to demonstrate that the fair value of properties acquired clearly exceeds the full cost ceiling limitation beyond a reasonable doubt in each reporting period. As part of the waiver received from the SEC, we are required to disclose what the full cost ceiling test impairment amounts for all periods presented in each applicable quarterly and annual filing would have been if the waiver had not been granted. The fair value of the properties acquired in the Merger was based on forward strip natural gas and oil pricing existing at the date of the Merger, and we affirmed that there has not been a material decline to the fair value of these acquired assets since the Merger. The properties acquired in the Merger have an unamortized cost at December 31, 2020 of $1,087 million. Had we not received the waiver from the SEC, the impairment charge recorded would have been an additional $539 million for the year ended December 31, 2020.
- The amortization rate is impacted by the timing and amount of reserve additions and the future development costs associated with those additions, revisions of previous reserve estimates due to both price and well performance, write-downs that result from non-cash full cost ceiling impairments, proceeds from the sale of properties that reduce the full cost pool, and the levels of costs subject to amortization. We cannot predict our future full cost pool amortization rate with accuracy due to the variability of each of the factors discussed above, as well as other factors, including but not limited to the uncertainty of the amount of future reserve changes.
- Unevaluated costs excluded from amortization were $1,472 million at December 31, 2020 compared to $1,506 million at December 31, 2019. The unevaluated costs excluded from amortization decreased, as compared to 2019, as the evaluation of previously unevaluated properties totaling $262 million in 2020 was only partially offset by the impact of $228 million of unevaluated capital invested, which included $90 million for Montage properties acquired during the same period.

See "Supplemental Oil and Gas Disclosures" in Item 8 of Part II of this Annual Report for additional information regarding our unevaluated costs excluded from amortization.

Impairments

- We recognized $2,825 million in non-cash full cost ceiling test impairments for the year ended December 31, 2020 primarily due to decreased commodity pricing over the prior 12 months. Additionally, we recognized a $5 million impairment to non-core assets.
- During the year ended December 31, 2019, we recognized non-cash impairments of $13 million associated with non-core E&P assets.

Marketing

	For the years ended December 31,		
(in millions except percentages)	2020	2019	Increase/ (Decrease)
Marketing revenues	$ 2,145	$ 2,849	(25)%
Other operating revenues	—	1	(100)%
Marketing purchases	2,129	2,833	(25)%
Operating costs and expenses	23	25	(8)%
Impairments	—	3	(100)%
Loss on sale of assets, net	—	2	(100)%
Operating income (loss)	$ (7)	$ (13)	(46)%
Volumes marketed *(Bcfe)*	1,138	1,101	3%
Percent natural gas production marketed from affiliated E&P operations	89 %	79 %	
Affiliated E&P oil and NGL production marketed	81 %	61 %	

Operating Loss

- Marketing operating loss decreased $6 million for the year ended December 31, 2020, compared to 2019, as 2019 included a $3 million impairment of non-core gathering assets, a $2 million loss on the sale of operating assets and $1 million in gas storage gains recorded in other operating revenues. Additionally, marketing operating loss for 2020 included a $2 million decrease in operating costs and expenses. For the year ended December 31, 2020, the marketing margin remained flat, compared to the prior year.

- The margin generated from marketing activities was $16 million for both years ended December 31, 2020 and 2019, respectively.

Marketing margins are driven primarily by volumes marketed and may fluctuate depending on the prices paid for commodities, related cost of transportation and the ultimate disposition of those commodities. Increases and decreases in revenues due to changes in commodity prices and volumes marketed are largely offset by corresponding changes in purchase expenses. Efforts to optimize the cost of our transportation can result in greater expenses and therefore lower marketing margins.

Revenues

- Revenues from our marketing activities decreased $704 million for the year ended December 31, 2020, compared to 2019, as a 27% decrease in the price received for volumes marketed more than offset a 37 Bcfe increase in the volumes marketed.

Operating Costs and Expenses

- Marketing operating costs and expenses decreased $2 million for the year ended December 31, 2020, compared to the year ended December 31, 2019, primarily due to decreased general and administrative expenses associated with decreased personnel costs and the implementation of cost reduction initiatives.

Consolidated

Interest Expense

(in millions except percentages)	For the years ended December 31, 2020	2019	Increase/ (Decrease)
Gross interest expense:			
Senior notes	$ 155	$ 155	—%
Credit arrangements	16	11	45%
Amortization of debt costs	11	8	38%
Total gross interest expense	182	174	5%
Less: capitalization	(88)	(109)	(19)%
Net interest expense	$ 94	$ 65	45%

- Interest expense related to our senior notes remained flat for the year ended December 31, 2020, as compared to 2019, as the interest savings from the repurchase of $107 million and $114 million of our outstanding senior notes in the first half of 2020 and the second half of 2019, respectively, was offset by the interest associated with the August 2020 public offering of $350 million aggregate principal amount of our 8.375% Senior Notes due 2028.
- Capitalized interest decreased $21 million for the year ended December 31, 2020, compared to 2019, due to the evaluation of natural gas and oil properties over the past twelve months.
- Capitalized interest decreased as a percentage of gross interest expense for the year ended December 31, 2020 as compared to 2019 primarily due to a larger percentage decrease in our unevaluated natural gas and oil properties balance as compared to the smaller percentage decrease in our gross interest expense over the same period.

Gain (Loss) on Derivatives

(in millions)	For the years ended December 31, 2020	2019
Gain (loss) on unsettled derivatives	$ (138)	$ 94
Gain on settled derivatives	362	180
Total gain on derivatives	$ 224	$ 274

We refer you to Note 6 to the consolidated financial statements included in this Annual Report for additional details about our gain (loss) on derivatives.

Gain (Loss) on Early Extinguishment of Debt

- In 2020, we recorded a gain on early extinguishment of debt of $35 million as a result of our repurchase of $107 million in aggregate principal amount of our outstanding senior notes for $72 million.
- In 2019, we recorded a gain of $8 million on early extinguishment of debt as a result of our repurchase of $62 million in aggregate principal amount of our outstanding senior notes. See Note 9 to the consolidated financial statements of this Annual Report for more information on our long-term debt.

Income Taxes

(in millions except percentages)	For the years ended December 31, 2020	2019
Income tax expense (benefit)	$ 407	$ (411)
Effective tax rate	(15)%	(86)%

- As of the first quarter of 2019, we had sustained a three-year cumulative level of profitability. Based on this factor and other positive evidence including forecasted income, we concluded that it was more likely than not that the deferred tax asset would be realized and released substantially all of the valuation allowance. This resulted in a discrete tax benefit of $411 million being recorded for the year ended December 31, 2019. However, due to commodity price declines during 2020 and the write-down of the current value of our natural gas and oil properties, in addition to other negative evidence, we concluded that it was more likely than not that these deferred tax assets will not be realized and recorded a discrete tax expense of $408 million for the increase in our valuation allowance in the first quarter of 2020. The net change in valuation allowance is reflected as a component of income tax expense. We also continue to retain a valuation allowance of $87 million related to net operating losses in jurisdictions in which we no longer operate.

We refer you to Note 11 to the consolidated financial statements included in this Annual Report for additional discussion about our income taxes.

LIQUIDITY AND CAPITAL RESOURCES

We depend primarily on funds generated from our operations, our 2018 credit facility, our cash and cash equivalents balance and capital markets as our primary sources of liquidity. In October 2020, the banks participating in our 2018 credit facility reaffirmed our elected borrowing base and aggregate commitments to be $1.8 billion. Upon the closing of the Merger in November 2020 and satisfaction of related conditions, the elected borrowing base and total aggregate commitments increased from $1.8 billion to $2.0 billion, the maximum permitted lien amount based on provisions in certain of our senior notes indentures. As of February 25, 2021, we had approximately $1.3 billion of total available liquidity, which exceeds our currently modeled needs, and looking forward in 2021, we remain committed to our strategy of free cash flow generation through capital discipline. We refer you to Note 9 to the consolidated financial statements included in this Annual Report and the section below under “Credit Arrangements and Financing Activities” for additional discussion of our 2018 credit facility and related covenant requirements.

Our cash flow from operating activities is highly dependent upon our ability to sell and the sales prices that we receive for our natural gas and liquids production. Natural gas, oil and NGL prices are subject to wide fluctuations and are driven by market supply and demand, which is impacted by many factors. See "Market Conditions and Commodity Prices" in the Overview section of Item 7 in Part II for additional discussion about current and potential future market conditions. The sales price we receive for our production is also influenced by our commodity derivative program. Our derivative contracts allow us to ensure a certain level of cash flow to fund our operations. In 2020, $362 million in realized gains on derivatives have offset a large portion of the impact of lower commodity prices, and although we are continually adding additional derivative positions for portions of our expected 2021, 2022 and 2023 production, there can be no assurance that we will be able to add derivative positions to cover the remainder of our expected production at favorable prices. See “Risk Factors” in Item 1A, “Quantitative and Qualitative Disclosures about Market Risk” in Item 7A and Note 6 in the consolidated financial statements included in this Annual Report for further details.

Our commodity hedging activities are subject to the credit risk of our counterparties being financially unable to settle the transaction. We actively monitor the credit status of our counterparties, performing both quantitative and qualitative assessments based on their credit ratings and credit default swap rates where applicable, and to date have not had any credit defaults associated with our transactions. However, any future failures by one or more counterparties could negatively impact our cash flow from operating activities.

Our short-term cash flows are also dependent on the timely collection of receivables from our customers and joint interest owners. We actively manage this risk through credit management activities and, through the date of this filing, have not experienced any significant write-offs for non-collectable amounts. However, any sustained inaccessibility of credit by our customers and joint interest owners could adversely impact our cash flows.

Due to these factors, we are unable to forecast with certainty our future level of cash flow from operations. Accordingly, we expect to adjust our discretionary uses of cash depending upon available cash flow. Further, we may from time to time seek to retire, rearrange or amend some or all of our outstanding debt or debt agreements through cash purchases, and/or exchanges, open market purchases, privately negotiated transactions, tender offers or otherwise. Such transactions, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Credit Arrangements and Financing Activities

In April 2018, we replaced our credit facility entered into in 2016 with a new revolving credit facility (the "2018 credit facility") with a group of banks that, as amended, has a maturity date of April 2024. The 2018 credit facility has an aggregate maximum revolving credit amount of $3.5 billion and, in October 2020, the banks participating in our 2018 credit facility reaffirmed the borrowing base to be $1.8 billion, which also reflected our aggregate commitments. Upon the closing of the Merger in November 2020, the borrowing base and total aggregate commitments were increased from $1.8 billion to $2.0 billion. The borrowing base is subject to redetermination at least twice a year, in April and October, and is subject to change based primarily on drilling results, commodity prices, our future derivative position, the level of capital investment and operating costs. On October 8, 2020, we entered into an amendment to the credit agreement governing the 2018 credit facility to, among other matters, limit our unrestricted cash and cash equivalents to $200 million when loans under the 2018 credit facility are outstanding, subject to certain exceptions, and to increase the applicable rate by 25 basis points on loans outstanding under the 2018 credit facility. The 2018 credit facility is secured by substantially all of our assets, including most of our subsidiaries. The permitted lien provisions in certain senior note indentures currently limit liens securing indebtedness to the greater of $2.0 billion or 25% of adjusted consolidated net tangible assets. We may utilize the 2018 credit facility in the form of loans and letters of credit. As of December 31, 2020, we had $700 million borrowings on our revolving credit facility and $233 million in outstanding letters of credit. We refer you to Note 9 to the consolidated financial statements included in this Annual Report for additional discussion of our revolving credit facility.

As of December 31, 2020, we were in compliance with all of the covenants contained in the credit agreement governing our revolving credit facility. Our ability to comply with financial covenants in future periods depends, among other things, on the success of our development program and upon other factors beyond our control, such as the market demand and prices for natural gas and liquids. We refer you to Note 9 of the consolidated financial statements included in this Annual Report for additional discussion of the covenant requirements of our 2018 revolving credit facility.

The credit status of the financial institutions participating in our revolving credit facility could adversely impact our ability to borrow funds under the revolving credit facility. Although we believe all of the lenders under the facility have the ability to provide funds, we cannot predict whether each will be able to meet their obligation to us. We refer you to Note 9 to the consolidated financial statements included in this Annual Report for additional discussion of our revolving credit facility.

Our exposure to the anticipated transition from LIBOR in late 2021 is limited to the 2018 credit facility. Upon announcement by the administrator of LIBOR identifying a specific date for LIBOR cessation, the credit agreement governing the 2018 credit facility will be amended to reference an alternative rate as established by JP Morgan, as Administrative Agent, and Southwestern. The alternative rate will be based on the prevailing market convention and is expected to be the Secured Overnight Financing Rate (or "SOFR").

In contemplation of the Merger with Montage, in August 2020, we completed a public offering of $350 million aggregate principal amount of our 2028 Notes, with net proceeds from the offering totaling approximately $345 million after underwriting discounts and offering expenses.

In August 2020, we completed a public offering of 63,250,000 shares of our common stock with an offering price to the public of $2.50 per share. Net proceeds, after deducting underwriting discounts and offering expenses, were approximately $152 million. The proceeds from the common stock offering, in conjunction with the issuance of the 2028 Notes and additional borrowings on our revolving credit facility were used to fund a redemption of $510 million aggregate principal amount of Montage Notes in connection with the closing of the Merger.

In 2020, we repurchased $6 million of our 4.10% Senior Notes due 2022, $36 million of our 4.95% Senior Notes due 2025, $21 million of our 7.50% Senior Notes due 2026 and $44 million of our 7.75% Senior Notes due 2027 for $72 million, and recognized a $35 million gain on the extinguishment of debt.

In the second half of 2019, we repurchased $35 million of our 4.95% Senior Notes due 2025, $11 million of our 7.50% Senior Notes due 2026 and $16 million of our 7.75% Senior Notes due 2027, and recognized an $8 million gain on extinguishment of debt. Additionally, in December 2019, we retired the remaining $52 million principal of our 4.05% Senior Notes due 2020. We refer you to Note 9 to the consolidated financial statements included in this Annual Report for additional discussion of our senior notes.

Because of the focused work on refinancing and repayment of our debt during the last three years, only $207 million, or 7%, of our outstanding debt balance as of December 31, 2020 is scheduled to become due prior to 2024.

At February 25, 2021, we had a long-term issuer credit rating of Ba2 by Moody's (rating and stable outlook affirmed on April 2, 2020), a long-term debt rating of BB- by S&P (rating affirmed and outlook upgraded to stable on October 15, 2020) and a long-term issuer default rating of BB by Fitch Ratings (rating affirmed and outlook upgraded to stable on January 29, 2021). In April 2020, S&P downgraded our bond rating to BB-, which had the effect of increasing the interest rate on the 2025 Notes to 6.45% in July 2020. The first coupon payment to the bondholders at the higher interest rate was January 2021. Any further upgrades or downgrades in our public debt ratings by Moody's or S&P could decrease or increase our cost of funds, respectively.

Cash Flows

	For the years ended December 31,	
(in millions)	2020	2019
Net cash provided by operating activities	$ 528	$ 964
Net cash used in investing activities	(881)	(1,045)
Net cash provided by (used in) financing activities	361	(115)

Cash Flow from Operations

(in millions)	For the years ended December 31, 2020	2019
Net cash provided by operating activities	$ 528	$ 964
Add back (subtract): changes in working capital	77	(69)
Net cash provided by operating activities, net of changes in working capital	$ 605	$ 895

- Net cash provided by operating activities decreased 45% or $436 million for the year ended December 31, 2020, compared to the same period in 2019, primarily due to a $574 million decrease resulting from lower commodity prices, a $146 million decreased impact of working capital, an $85 million increase in operating costs and a $29 million increase in interest expense. The decreases were partially offset by a $216 million increase associated with increased production and a $182 million increase in our settled derivatives.
- Net cash generated from operating activities, net of changes in working capital, provided 67% of our cash requirements for capital investments for the year ended December 31, 2020, compared to providing 79% of our cash requirements for capital investments for the same period in 2019.

Cash Flow from Investing Activities

- Total E&P capital investing decreased $239 million for the year ended December 31, 2020, compared to the same period in 2019, due to a $197 million decrease in direct E&P capital investing, a $21 million decrease in capitalized internal costs and a $21 million decrease in capitalized interest.
- The decrease in capitalized interest for the year ended December 31, 2020, as compared to the same period in 2019, was primarily due to the evaluation of natural gas and oil properties over the past twelve months.

(in millions)	For the years ended December 31, 2020	2019
Additions to properties and equipment	$ 896	$ 1,099
Adjustments for capital investments:		
Changes in capital accruals	(3)	35
Other [(1)]	6	6
Total capital investing	$ 899	$ 1,140

(1) Includes capitalized non-cash stock-based compensation and costs to retire assets, which are classified as cash used in operating activities.

Capital Investing

(in millions except percentages)	For the years ended December 31, 2020	2019	Increase/ (Decrease)
E&P capital investing	$ 899	$ 1,138	
Other capital investing [(1)]	—	2	
Total capital investing	$ 899	$ 1,140	(21)%

(1) Other capital investing was immaterial for the year ended December 31, 2020.

(in millions)	For the years ended December 31, 2020	2019
E&P Capital Investments by Type:		
Exploratory and development, including workovers	$ 692	$ 838
Acquisition of properties	37	55
Seismic expenditures	—	3
Water infrastructure project	9	35
Other	17	21
Capitalized interest and expenses	144	186
Total E&P capital investments	$ 899	$ 1,138
E&P Capital Investments by Area		
Northeast Appalachia	$ 362	$ 365
Southwest Appalachia	510	710
Other E&P [(1)]	27	63
Total E&P capital investments	$ 899	$ 1,138

(1) Includes $9 million and $35 million for the years ended December 31, 2020 and 2019, respectively, related to our water infrastructure project.

	For the years ended December 31, 2020	2019
Gross Operated Well Count Summary:		
Drilled	98	105
Completed	96	116
Wells to sales	100	113

Actual capital expenditure levels may vary significantly from period to period due to many factors, including drilling results, natural gas, oil and NGL prices, industry conditions, the prices and availability of goods and services, and the extent to which properties are acquired or non-strategic assets are sold.

Cash Flow from Financing Activities

- Net cash provided by financing activities for the year ended December 31, 2020 was $361 million, compared to net cash used in financing activities of $115 million for the same period in 2019.
- In August 2020, we completed debt and equity offerings resulting in $345 million and $152 million in net proceeds, respectively.
- In November 2020, we paid $522 million to retire the Montage senior notes, and repaid the outstanding balance of $200 million related to Montage's revolving credit facility.
- In 2020, we repurchased $107 million in aggregate principal amount of our outstanding senior notes at a discount for $72 million and recognized a $35 million gain on the extinguishment of debt.
- In 2019, we paid $54 million on the open market to repurchase $62 million of our outstanding senior notes at a discount. We recognized a gain on early extinguishment of debt of $8 million.
- In December 2019, we retired the remaining $52 million principal of our 4.05% Senior Notes due January 2020.
- In January 2019, we repurchased approximately 5 million shares of common stock for approximately $21 million.

We refer you to Note 9 to the consolidated financial statements included in this Annual Report for additional discussion of our outstanding debt and credit facility and to Note 1 for additional discussion of our equity offering.

Working Capital

- We had negative working capital of $341 million at December 31, 2020, a $172 million decrease from December 31, 2019, as an $8 million increase in cash and cash equivalents was more than offset by a $70 million increase in various payables and a $157 million net reduction in the current mark-to-market value of our derivative position related to improved forward strip pricing across all commodities as compared to December 2019. Additionally, other current liabilities at December 31, 2020 decreased $34 million, compared to December 31, 2019, as a $43 million decrease in our accrued firm transportation liability related to the Fayetteville Shale sale was only partially offset by a prepayment that we received for an unrelated firm transportation assumption. We believe that our existing cash and cash equivalents, our anticipated cash flow from operations and our available credit facility will be sufficient to meet our working capital and operational spending requirements.

Off-Balance Sheet Arrangements

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of December 31, 2020, our material off-balance sheet arrangements and transactions include operating service arrangements, $233 million in letters of credit outstanding against our 2018 revolving credit facility and $221 million in outstanding surety bonds. There are no other transactions, arrangements or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect our liquidity or availability of our capital resources. For more information regarding off-balance sheet arrangements, we refer you to "Contractual Obligations and Contingent Liabilities and Commitments" below for more information on our operating leases.

Contractual Obligations and Contingent Liabilities and Commitments

We have various contractual obligations in the normal course of our operations and financing activities. Significant contractual obligations as of December 31, 2020, were as follows:

Contractual Obligations:

	Payments Due by Period					
(in millions)	Total	Less than 1 Year	1 to 3 Years	3 to 5 Years	5 to 8 Years	More than 8 Years
Transportation charges [1]	**$ 8,544**	$ 862	$ 1,562	$ 1,323	$ 1,901	$ 2,896
Debt	**3,171**	—	207	1,556	1,408	—
Interest on debt [2]	**1,070**	199	382	310	179	—
Operating leases [3]	**131**	30	39	26	30	6
Compression services [4]	**37**	20	14	3	—	—
Operating agreements	**4**	4	—	—	—	—
Purchase obligations	**45**	45	—	—	—	—
Other obligations [5]	**12**	9	3	—	—	—
	$ 13,014	$ 1,169	$ 2,207	$ 3,218	$ 3,518	$ 2,902

(1) As of December 31, 2020, we had commitments for demand and similar charges under firm transportation and gathering agreements to guarantee access capacity on natural gas and liquids pipelines and gathering systems. Of the total $8.5 billion, $531 million related to access capacity on future pipeline and gathering infrastructure projects that still require the granting of regulatory approvals and/or additional construction efforts. For further information, we refer you to "Operational Commitments and Contingencies" in Note 10 to the consolidated financial statements included in this Annual Report. This amount also included guarantee obligations of up to $923 million.

With the close of the Montage Merger we acquired firm transportation commitments of approximately $1,100 million. These commitments approximate $99 million within the next year, $197 million from 1 to 3 years, $196 million from 3 to 5 years, $284 million from 5 to 8 years and $324 million beyond 8 years.

In the first quarter of 2019, we agreed to purchase firm transportation with pipelines in the Appalachian basin starting in 2021 and running through 2032 totaling $357 million in total contractual commitments of which the seller has agreed to reimburse $133 million of these commitments.

(2) Interest payments on our senior notes were calculated utilizing the fixed rates associated with our fixed rate notes outstanding at December 31, 2020. Senior note interest rates were based on our credit ratings as of December 31, 2020.

(3) Operating leases include costs for compressors, drilling rigs, pressure pumping equipment, office space and other equipment under non-cancelable operating leases expiring through 2036.

(4) As of December 31, 2020, our E&P segment had commitments of approximately $37 million for compression services associated primarily with our Southwest Appalachia division.

(5) Our other significant contractual obligations include approximately $12 million for various information technology support and data subscription agreements.

Future contributions to the pension and postretirement benefit plans are excluded from the table above. For further information regarding our pension and other postretirement benefit plans, we refer you to Note 13 to the consolidated financial statements included in this Annual Report and "Critical Accounting Policies and Estimates" below for additional information.

We refer you to Note 9 to the consolidated financial statements included in this Annual Report for a discussion of the terms of our debt.

We are subject to various litigation, claims and proceedings that arise in the ordinary course of business, such as for alleged breaches of contract, miscalculation of royalties, employment matters, traffic incidents, pollution, contamination, encroachment on others' property or nuisance. We accrue for such items when a liability is both probable and the amount can be reasonably estimated. Management believes that current litigation, claims and proceedings, individually or in aggregate and after taking into account insurance, are not likely to have a material adverse impact on our financial position, results of operations or cash flows, although it is possible that adverse outcomes could have a material adverse effect on our results of operations or cash flows for the period in which the effect of that outcome becomes reasonably estimable. Many of these matters are in early stages, so the allegations and the damage theories have not been fully developed, and are all subject to inherent uncertainties; therefore, management's view may change in the future.

We are also subject to laws and regulations relating to the protection of the environment. Environmental and cleanup related costs of a non-capital nature are accrued when it is both probable that a liability has been incurred and when the amount can be reasonably estimated. Management believes any future remediation or other compliance related costs will not have a material effect on our financial position, results of operations or cash flows.

For further information, we refer you to "Litigation" and "Environmental Risk" in Note 10 to the consolidated financial statements included in this Annual Report.

Supplemental Guarantor Financial Information

As discussed in Note 9, in April 2018 the Company entered into the 2018 credit facility. Pursuant to requirements under the indentures governing our senior notes, each 100% owned subsidiary that became a guarantor of the 2018 credit facility also became a guarantor of each of our senior notes (the "Guarantor Subsidiaries"). The Guarantor Subsidiaries also granted liens and security interests to support their guarantees under the 2018 credit facility but not of the senior notes. These guarantees are full and unconditional and joint and several among the Guarantor Subsidiaries. Certain of our operating units which are accounted for on a consolidated basis do not guarantee the 2018 credit facility and senior notes.

Upon the November 2020 closing of the Merger with Montage, certain Montage entities owning oil and gas properties became guarantors to the 2018 credit facility.

The Company and the Guarantor Subsidiaries jointly and severally, and fully and unconditionally, guarantee the payment of the principal and premium, if any, and interest on the senior notes when due, whether at stated maturity of the senior notes, by acceleration, by call for redemption or otherwise, together with interest on the overdue principal, if any, and interest on any overdue interest, to the extent lawful, and all other obligations of the Company to the holders of the senior notes.

SEC Regulation S-X Rule 13-01 requires the presentation of "Summarized Financial Information" to replace the "Condensed Consolidating Financial Information" required under Rule 3-10. Rule 13-01 allows the omission of Summarized Financial Information if assets, liabilities and results of operations of the Guarantors are not materially different than the corresponding amounts presented in the consolidated financial statements of the Company. The Parent and Guarantor Subsidiaries comprise the material operations of the Company. Therefore, the Company concluded that the presentation of the Summarized Financial Information is not required as the Summarized Financial Information of the Company's Guarantors is not materially different from our consolidated financial statements.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The discussion and analysis of financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires management to make estimates and judgments that affect the amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. We evaluate our estimates on an on-going basis, based on historical experience and on various other assumptions that are believed to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. We believe the following describes significant judgments and estimates used in the preparation of our consolidated financial statements.

Natural Gas and Oil Properties

We utilize the full cost method of accounting for costs related to the exploration, development and acquisition of natural gas and oil properties. Under this method, all such costs (productive and nonproductive), including salaries, benefits and other internal costs directly attributable to these activities, are capitalized on a country-by-country basis and amortized over the estimated lives of the properties using the units-of-production method. These capitalized costs are subject to a quarterly ceiling test that limits such pooled costs, net of applicable deferred taxes, to the aggregate of the present value of future net revenues attributable to proved natural gas, oil and NGL reserves discounted at 10% (standardized measure) plus the lower of cost or market value of unproved properties. Any costs in excess of the ceiling are written off as a non-cash expense. The expense may not be reversed in future periods, even though higher natural gas, oil and NGL prices may subsequently increase the ceiling. Companies using the full cost method are required to use the average quoted price from the first day of each month from the previous 12 months, including the impact of derivatives designated for hedge accounting, to calculate the ceiling value of their reserves.

Costs associated with unevaluated properties are excluded from our amortization base until we have evaluated the properties or impairment is indicated. The costs associated with unevaluated leasehold acreage and related seismic data, wells currently drilling and related capitalized interest are initially excluded from our amortization base. Leasehold costs are either transferred to our amortization base with the costs of drilling a well on the lease or are assessed at least annually for possible impairment or reduction in value. Our decision to withhold costs from amortization and the timing of the transfer of those costs into the amortization base involves judgment and may be subject to changes over time based on several factors, including our drilling plans, availability of capital, project economics and drilling results from adjacent acreage. At December 31, 2020, we had approximately $1,472 million of costs excluded from our amortization base, all of which related to our properties in the United States. Inclusion of some or all of these costs in our properties in the United States in the future, without adding any associated reserves, could result in non-cash ceiling test impairments.

At December 31, 2020, the ceiling value of our reserves was calculated based upon the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $1.98 per MMBtu, for West Texas Intermediate oil of $39.57 per barrel and NGLs of $10.27 per barrel, adjusted for market differentials. The net book value of our natural gas and oil properties exceeded the ceiling amount in each quarter of 2020 resulting in total non-cash full cost ceiling test write-downs of $2,825 million. We had no derivative positions that were designated for hedge accounting as of December 31, 2020. Future decreases in market prices, as well as changes in production rates, levels of reserves, evaluation costs excluded from amortization, future development costs and production costs may result in further non-cash impairments to our natural gas and oil properties.

No impairment expense was recorded for the year ended December 31, 2020 in relation to our recently acquired Montage natural gas and oil properties. These properties were recorded at fair value as of November 13, 2020, in accordance with ASC 820 *Fair Value Measurement*. Pursuant to SEC guidance, we determined that the fair value of the properties acquired at the closing of the Merger clearly exceeded the related full-cost ceiling limitation beyond a reasonable doubt and received a waiver from the SEC to exclude the properties acquired in the Merger from the ceiling test calculation. This waiver was granted for all reporting periods through and including the quarter ending September 30, 2021 as long as we can continue to demonstrate that the fair value of properties acquired clearly exceeds the full cost ceiling limitation beyond a reasonable doubt in each reporting period. As part of the waiver received from the SEC, we are required to disclose what the full cost ceiling test impairment amounts for all periods presented in each applicable quarterly and annual filing would have been if the waiver had not been granted. The fair value of the properties acquired in the Merger was based on forward strip natural gas and oil pricing existing at the date of the Merger, and we affirmed that there has not been a material decline to the fair value of these acquired assets since the Merger. The properties acquired in the Merger have an unamortized cost at December 31, 2020 of $1,087 million. Had we not received the waiver from the SEC, the impairment charge recorded would have been an additional $539 million for the year ended December 31, 2020.

Using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $2.58 per MMBtu, West Texas Intermediate oil of $55.69 per barrel and NGLs of $11.58 per barrel, adjusted for market differentials, the net book value of our United States natural gas and oil properties did not exceed the ceiling amount and did not result in a ceiling test impairment at December 31, 2019. We had no derivative positions that were designated for hedge accounting as of December 31, 2019.

Changes in natural gas, oil and NGL prices used to calculate the discounted future net revenues of our reserves affects both the present value of cash flows and the quantity of reserves. Our reserve base as of December 31, 2020 was approximately 76% natural gas, 3% NGLs and 21% oil, and our standardized measure and reserve quantities as of December 31, 2020, were $1.85 billion and 12.0 Tcfe, respectively.

Proved natural gas, oil and NGL reserves are a major component of the full cost ceiling test. Natural gas, oil and NGL reserves cannot be measured exactly. Our estimate of natural gas, oil and NGL reserves requires extensive judgments of reservoir engineering data and projections of costs that will be incurred in developing and producing reserves and is generally less precise than other estimates made in connection with financial disclosures. Our reservoir engineers prepare our reserve estimates under the supervision of our management. Reserve estimates are prepared for each of our properties annually by the reservoir engineers assigned to the asset management team for that property. The reservoir engineering and financial data included in these estimates are reviewed by senior engineers, who are not part of the asset management teams, and by our Director of Reserves, who is the technical person primarily responsible for overseeing the preparation of our reserves estimates. Our Director of Reserves has more than 26 years of experience in petroleum engineering, including the estimation of natural gas and oil reserves, and holds a Bachelor of Science in Petroleum Engineering. Prior to joining us in 2018, our Director of Reserves served in various reservoir engineering roles for EP Energy Company, El Paso Corporation, Cabot Oil & Gas Corporation, Schlumberger and H.J. Gruy & Associates, and is a member of the Society of Petroleum Engineers. He reports to our Executive Vice President and Chief Operating Officer, who has more than 32 years of experience in petroleum engineering including the estimation of natural gas, oil and NGL reserves in multiple basins in the United States, and holds a Bachelor of Science in Petroleum Engineering. Prior to joining Southwestern in 2017, our Chief Operating Officer served in various engineering and leadership roles for EP Energy Corporation, El Paso Corporation, ARCO Oil and Gas Company, Burlington Resources and Peoples Energy Production, and is a member of the Society of Petroleum Engineers.

We engage NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies, to independently audit our proved reserves estimates as discussed in more detail below. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-002699. Within NSAI, the two technical persons primarily responsible for auditing our proved reserves estimates (1) have over 23 years and over 19 years of practical experience in petroleum geosciences and petroleum engineering, respectively; (2) have over 12 years and over 19 years of experience in the estimation and evaluation of reserves, respectively; (3) each has a college degree; (4) each is a Licensed Professional Geoscientist in the State of Texas or a Licensed Professional Engineer in the State of Texas; (5) each meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; and (6) each is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines. The financial data included in the reserve estimates is also separately reviewed by our accounting staff. Our proved reserves estimates, as internally reviewed and audited by NSAI, are submitted for review and approval to our President and Chief Executive Officer. Finally, upon his approval, NSAI reports the results of its reserve audit to the Board of Directors, with whom final authority over the estimates of our proved reserves rests. A copy of NSAI's report has been filed as Exhibit 99.1 to this Annual Report.

Proved developed reserves generally have a higher degree of accuracy in this estimation process, when compared to proved undeveloped and proved non-producing reserves, as production history and pressure data over time is available for the majority of our proved developed properties. Proved developed reserves accounted for 68% of our total reserve base as of December 31, 2020. Assigning monetary values to such estimates does not reduce the subjectivity and changing nature of such reserve estimates. The uncertainties inherent in the reserve estimates are compounded by applying additional estimates of the rates and timing of future production volumes and the costs that will be incurred in developing and producing the reserves. We cannot assure you that our internal controls sufficiently address the numerous uncertainties and risks that are inherent in estimating quantities of natural gas, oil and NGL reserves and projecting future rates of production and timing of development expenditures as many factors are beyond our control. We refer you to "Our proved natural gas, oil and NGL reserves are estimates that include uncertainties. Any material changes to these uncertainties or underlying assumptions could cause the quantities and net present value of our reserves to be overstated or understated" in Item 1A, "Risk Factors," of Part I of this Annual Report for a more detailed discussion of these uncertainties, risks and other factors.

In conducting its audit, the engineers and geologists of NSAI study our major properties in detail and independently develop reserve estimates. NSAI's audit consists primarily of substantive testing, which includes a detailed review of major properties that account for approximately 97% of the present worth of the company's total proved reserves. NSAI's audit process consists of sorting all fields by descending present value order and selecting the fields from highest value to descending value until the selected fields account for more than 80% of the present worth of our reserves. The fields included in approximately the top 99% present value as of December 31, 2020, accounted for approximately 99% of our total proved reserves and approximately 100% of our proved undeveloped reserves. In the conduct of its audit, NSAI did not independently verify the data we provided to them with respect to ownership interests, natural gas, oil and NGL production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the properties and sales of production. NSAI has advised us that if, in the course of its audit, something came to its attention that brought into question the validity or sufficiency of any such information or data, NSAI did not rely on such information or data until it had satisfactorily resolved any questions relating thereto or had independently verified such information or data. On February 9, 2021, NSAI issued its audit opinion as to the reasonableness of our reserve estimates for the year-ended December 31, 2020 stating that our estimated proved natural gas, oil and NGL reserves are, in the aggregate, reasonable and have been prepared in accordance with Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

Business Combinations

We account for business combinations under the acquisition method of accounting. Accordingly, we recognize amounts for identifiable assets acquired and liabilities assumed equal to their estimated acquisition date fair values. We make various assumptions in estimating the fair values of assets acquired and liabilities assumed. As fair value is a market-based measurement, it is determined based on the assumptions that market participants would use. The most significant assumptions relate to the estimated fair values of proved and unproved oil and natural gas properties. Fair value of proved natural gas and oil properties as of the acquisition date was based on estimated proved natural gas, oil and NGL reserves and related discounted net cash flows. Significant inputs to the valuation include estimates of future production volumes, future operating and development costs, future commodity prices and a weighted average cost of capital rate. The market-based weighted average cost of capital rate is subjected to additional project-specific risking factors. In addition, when appropriate, we review comparable purchases and sales of natural gas and oil properties within the same regions, and use that data as a proxy for fair market value; for example, the amount a willing buyer and seller would enter into in exchange for such properties. Any excess of the acquisition price over the estimated fair value of net assets acquired is recorded as goodwill. Any excess of the estimated fair value of net assets acquired over the acquisition price is recorded in current earnings as a gain on bargain purchase. Deferred taxes are recorded for any differences between the assigned values and the tax basis of assets and liabilities.

The Merger with Montage qualified as a business combination, and as such, we estimated the fair value of the assets acquired and liabilities assumed as of the November 13, 2020 acquisition date. The fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). Fair value measurements also utilize assumptions of market participants. We used a discounted cash flow model and made market assumptions as to future commodity prices, projections of estimated quantities of natural gas and oil reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates. These assumptions represent Level 3 inputs, as defined in Note 8 – Fair Value Measurements. We recorded the net assets acquired and liabilities assumed in the Montage Merger at their estimated fair value of approximately $213 million, which we consider to be representative of the price paid by a typical market participant. This measurement resulted in no goodwill or bargain purchase being recognized.

Derivatives and Risk Management

We use fixed price swap agreements and options to reduce the volatility of earnings and cash flow due to fluctuations in the prices of certain commodities and interest rates. Our policies prohibit speculation with derivatives and limit agreements to counterparties with appropriate credit standings to minimize the risk of uncollectability. We actively monitor the credit status of our counterparties based on their credit ratings and credit default swap rates where applicable, and to date have not had any credit defaults associated with our transactions. In 2020 and 2019, we financially protected 83% and 69%, respectively, of our total production with derivatives. The primary risks related to our derivative contracts are the volatility in market prices and basis differentials for our production. However, the market price risk is generally offset by the gain or loss recognized upon the related transaction that is financially protected.

All derivatives are recognized in the balance sheet as either an asset or a liability as measured at fair value other than transactions for which the normal purchase/normal sale exception is applied. Certain criteria must be satisfied for derivative financial instruments to be designated for hedge accounting. Accounting guidance for qualifying hedges allows an unsettled derivative's unrealized gains and losses to be recorded in either earnings or as a component of other comprehensive income until settled. In the period of settlement, we recognize the gains and losses from these qualifying hedges in gas sales revenues. The ineffective portion of those fixed price swaps are recognized in earnings. Gains and losses on derivatives that are not designated for hedge accounting treatment, or that do not meet hedge accounting requirements, are recorded as a component of gain (loss) on derivatives on the consolidated statements of operations. Accordingly, the gain (loss) on derivatives component of the statement of operations reflects the gains and losses on both settled and unsettled derivatives. We calculate gains and losses on settled derivatives as the summation of gains and losses on positions which have settled within the reporting period.

As of December 31, 2020, none of our derivative contracts were designated for hedge accounting treatment. Changes in the fair value of unsettled derivatives that were not designated for hedge accounting treatment are recorded in gain (loss) on derivatives. See Note 6 to the consolidated financial statements included in this Annual Report for more information on our derivative position at December 31, 2020.

Future market price volatility could create significant changes to the derivative positions recorded in our consolidated financial statements. We refer you to "Quantitative and Qualitative Disclosures about Market Risk" in Item 7A of Part II of this Annual Report for additional information regarding our hedging activities.

Pension and Other Postretirement Benefits

We record our prepaid or accrued benefit cost, as well as our periodic benefit cost, for our pension and other postretirement benefit plans using measurement assumptions that we consider reasonable at the time of calculation (see Note 13 to the consolidated financial statements included in this Annual Report for further discussion and disclosures regarding these benefit plans). Two of the assumptions that affect the amounts recorded are the discount rate, which estimates the rate at which benefits could be effectively settled, and the expected return on plan assets, which reflects the average rate of earnings expected on the funds invested. For the December 31, 2020 benefit obligation the initial discount rate assumed is 3.10%. This compares to an initial discount rate of 3.70% for the benefit obligation and periodic benefit cost recorded in 2020. As part of ongoing effort to reduce costs, we have elected to freeze our pension plan effective January 1, 2021. Employees that were participants in the pension plan prior to January 1, 2021 will continue to receive the interest component of the plan but will no longer receive the service component. For the 2021 periodic benefit cost, the expected return assumed was reduced from 6.50% to 5.10%.

Using the assumed rates discussed above, we recorded total benefit cost of $9 million in 2020 related to our pension and other postretirement benefit plans. Due to the significance of the discount rate and expected long-term rate of return, the following sensitivity analysis demonstrates the effect that a 0.5% change in those assumptions would have had on our 2020 pension expense:

	Increase (Decrease) of Annual Pension Expense	
(in millions)	0.5% Increase	0.5% Decrease
Discount rate	$ (1)	$ 1
Expected long-term rate of return	$ —	$ —

As of December 31, 2020, we recognized a liability of $46 million, compared to $43 million at December 31, 2019, related to our pension and other postretirement benefit plans. During 2020, we made cash contributions totaling $13 million to fund our pension and other postretirement benefit plans.

Long-term Incentive Compensation

Our long-term incentive compensation plans consist of a combination of stock-based awards that derive their value directly or indirectly from our common stock price, and cash-based awards that are fixed in amount, but subject to meeting annual performance thresholds. In March 2020, we issued our first long-term fixed cash-based awards.

We account for long-term incentive compensation transactions using a fair value method and recognize an amount equal to the fair value of the stock-based awards and cash-based awards cost in either the consolidated statement of operations or capitalize the cost into natural gas and oil properties included in property and equipment. Costs are capitalized when they are directly related to the acquisition, exploration and development activities of our natural gas and oil properties. We use models to determine fair value of stock-based compensation, which requires significant judgment with respect to forfeitures, volatility and other factors. The performance cash awards granted in 2020 include a performance condition determined annually by the Company. If we, in our sole discretion, determine that the threshold was not met, the amount for that vesting period will not vest and will be cancelled.

Our stock-based compensation is classified as either an equity award or a liability award in accordance with generally accepted accounting principles. The fair value of an equity-classified award is determined at the grant date and is amortized on a straight-line basis over the vesting life of the award. The fair-value of a liability-classified award is determined on a quarterly basis through the final vesting date and is amortized based on the current fair value of the award and the percentage of vesting period incurred to date. See Note 14 to the consolidated financial statements included in this Annual Report for further discussion and disclosures regarding our long-term incentive compensation.

New Accounting Standards

Refer to Note 1 to the consolidated financial statements included in this Annual Report for further discussion of our significant accounting policies and for discussion of accounting standards that have been implemented in this report, along with a discussion of relevant accounting standards that are pending adoption.

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

All statements, other than historical fact or present financial information, may be deemed to be forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements that address activities, outcomes and other matters that should or may occur in the future, including, without limitation, statements regarding the financial position, business strategy, production and reserve growth and other plans and objectives for our future operations, are forward-looking statements. Although we believe the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance. We have no obligation and make no undertaking to publicly update or revise any forward-looking statements, except as may be required by law.

Forward-looking statements include the items identified in the preceding paragraph, information concerning possible or assumed future results of operations and other statements in this Annual Report identified by words such as “anticipate,” “intend,” “plan,” “project,” “estimate,” “continue,” “potential,” “should,” “could,” “may,” “will,” “objective,” “guidance,” “outlook,” “effort,” “expect,” “believe,” “predict,” “budget,” “projection,” “goal,” “forecast,” “model,” “target” or similar words. Statements may be forward-looking even in the absence of these particular words.

You should not place undue reliance on forward-looking statements. They are subject to known and unknown risks, uncertainties and other factors that may affect our operations, markets, products, services and prices and cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with forward-looking statements, risks, uncertainties and factors that could cause our actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- the timing and extent of changes in market conditions and prices for natural gas, oil and NGLs (including regional basis differentials) and the impact of reduced demand for our production and products in which our production is a component due to governmental and societal actions taken in response to the COVID-19 or other pandemic;
- our ability to fund our planned capital investments;
- a change in our credit rating, an increase in interest rates and any adverse impacts from the discontinuation of the London Interbank Offered Rate ("LIBOR");
- the extent to which lower commodity prices impact our ability to service or refinance our existing debt;
- the impact of volatility in the financial markets or other global economic factors, including the impact of COVID-19 or other diseases;
- difficulties in appropriately allocating capital and resources among our strategic opportunities;
- the timing and extent of our success in discovering, developing, producing and estimating reserves;
- our ability to maintain leases that may expire if production is not established or profitably maintained;
- our ability to realize the expected benefits from acquisitions, including the Merger;
- costs in connection with the Merger;
- integration of operations and results subsequent to the Merger;
- our ability to transport our production to the most favorable markets or at all;
- availability and costs of personnel and of products and services provided by third parties;
- the impact of government regulation, including changes in law, the ability to obtain and maintain permits, any increase in severance or similar taxes, and legislation or regulation relating to hydraulic fracturing or other drilling and completing techniques, climate and over-the-counter derivatives;
- the impact of the adverse outcome of any material litigation against us or judicial decisions that affect us or our industry generally;
- the effects of weather or power outages;
- increased competition;
- the financial impact of accounting regulations and critical accounting policies;
- the comparative cost of alternative fuels;
- credit risk relating to the risk of loss as a result of non-performance by our counterparties; and
- any other factors listed in the reports we have filed and may file with the SEC.

Should one or more of the risks or uncertainties described above or elsewhere in this Annual Report occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. We specifically disclaim all responsibility to update publicly any information contained in a forward-looking statement or any forward-looking statement in its entirety and therefore disclaim any resulting liability for potentially related damages.

All forward-looking statements attributable to us are expressly qualified in their entirety by this cautionary statement.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market risks relating to our operations result primarily from the volatility in commodity prices, basis differentials and interest rates, as well as service costs and credit risk concentrations. We use fixed price swap agreements, options, swaptions, basis swaps and interest rate swaps to reduce the volatility of earnings and cash flow due to fluctuations in the prices of natural gas, oil and certain NGLs along with interest rates. Our Board of Directors has approved risk management policies and procedures to utilize financial products for the reduction of defined commodity price risk. Utilization of financial products for the reduction of interest rate risks is also overseen by our Board of Directors. These policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings.

Credit Risk

Our exposure to concentrations of credit risk consists primarily of trade receivables and derivative contracts associated with commodities trading. Concentrations of credit risk with respect to receivables are limited due to the large number of our purchasers and their dispersion across geographic areas. For the year ended December 31, 2020, one purchaser accounted for 10% of our revenues. A default on this account could have a material impact on the Company, but we do not believe that there is a material risk of a default. No single purchaser accounted for greater than 10% of revenues during the year ended December 31, 2019. We believe that the loss of any one customer would not have an adverse effect on our ability to sell our natural gas, oil and NGL production. See "Commodities Risk" below for discussion of credit risk associated with commodities trading.

Interest Rate Risk

As of December 31, 2020, we had approximately $2.5 billion of outstanding senior notes with a weighted average interest rate of 7.02%, and $700 million of borrowings under our revolving credit facility. We currently have an interest rate swap in effect to mitigate a portion of our exposure to volatility in interest rates. At December 31, 2020, we had a long-term issuer credit rating of Ba2 by Moody's, a long-term debt rating of BB- by S&P and a long-term debt issuer default rating of BB by Fitch Ratings. In April 2020, S&P downgraded our bond rating to BB-, which had the effect of increasing the interest rate on our 2025 Notes to 6.45% following the July 23, 2020 interest payment date. The first coupon payment to the bondholders at the higher interest rate will be paid in January 2021. Any further upgrades or downgrades in our public debt ratings by Moody's or S&P could decrease or increase our cost of funds, respectively.

	Expected Maturity Date						
(in millions except percentages)	2021	2022	2023	2024	2025	Thereafter	**Total**
Fixed rate payments (1)	$ —	$ 207	$ —	$ —	$ 856	$ 1,408	**$ 2,471**
Weighted average interest rate	— %	4.10 %	— %	— %	6.45 %	7.80 %	**7.02 %**
Variable rate payments (1)	$ —	$ —	$ —	$ 700	$ —	$ —	**$ 700**
Weighted average interest rate	— %	— %	— %	2.11 %	— %	— %	**2.11 %**

(1) Excludes unamortized debt issuance costs and debt discounts.

Commodities Risk

We use over-the-counter fixed price swap agreements and options to protect sales of our production against the inherent risks of adverse price fluctuations or locational pricing differences between a published index and the NYMEX futures market. These swaps and options include transactions in which one party will pay a fixed price (or variable price) for a notional quantity in exchange for receiving a variable price (or fixed price) based on a published index (referred to as price swaps) and transactions in which parties agree to pay a price based on two different indices (referred to as basis swaps).

The primary market risks relating to our derivative contracts are the volatility in market prices and basis differentials for our production. However, the market price risk is offset by the gain or loss recognized upon the related sale or purchase of the production that is financially protected. Credit risk relates to the risk of loss as a result of non-performance by our counterparties. The counterparties are primarily major banks and integrated energy companies that management believes present minimal credit risks. The credit quality of each counterparty and the level of financial exposure we have to each counterparty are closely monitored to limit our credit risk exposure. Additionally, we perform both quantitative and qualitative assessments of these counterparties based on their credit ratings and credit default swap rates where applicable. We have not incurred any counterparty losses related to non-performance and do not anticipate any losses given the information we have currently. However, we cannot be certain that we will not experience such losses in the future. The fair value of our derivative assets and liabilities includes a non-performance risk factor. We refer you to Note 6 and Note 8 of the consolidated financial statements included in this Annual Report for additional details about our derivative instruments and their fair value.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Management’s Report on Internal Control Over Financial Reporting

It is the responsibility of the management of Southwestern Energy Company to establish and maintain adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934). Management has assessed the effectiveness of the Company’s internal control over financial reporting as of December 31, 2020, utilizing the Committee of Sponsoring Organizations of the Treadway Commission’s Internal Control – Integrated Framework (2013).

Based on this evaluation, management has concluded the Company’s internal control over financial reporting was effective as of December 31, 2020.

Management’s assessment and conclusion on the effectiveness of the Company’s internal control over financial reporting as of December 31, 2020 excludes an assessment of the internal control over financial reporting of Montage Resources, which was acquired in a business combination on November 13, 2020. Montage represents approximately 22% of our consolidated total assets at December 31, 2020 and 3% of our consolidated revenues for the fiscal year ended December 31, 2020.

The effectiveness of our internal control over financial reporting as of December 31, 2020 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report which appears herein.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Southwestern Energy Company

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Southwestern Energy Company and its subsidiaries (the “Company”) as of December 31, 2020 and 2019, and the related consolidated statements of operations, of comprehensive income (loss), of changes in equity and of cash flows for each of the three years in the period ended December 31, 2020, including the related notes (collectively referred to as the “consolidated financial statements”). We also have audited the Company's internal control over financial reporting as of December 31, 2020, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2020, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

Basis for Opinions

The Company’s management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management’s Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on the Company’s consolidated financial statements and on the Company’s internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As described in Management's Report on Internal Control Over Financial Reporting, management has excluded Montage Resources, Inc. ("Montage") from its assessment of internal control over financial reporting as of December 31, 2020 because it was acquired by the Company in a purchase business combination during 2020. We have also excluded Montage from our audit of internal control over financial reporting. Montage is a wholly-owned subsidiary whose total assets and total revenues excluded from management's assessment and our audit of internal control over financial reporting represent 22% and 3%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2020.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that (i) relate to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

The Impact of Proved Natural Gas, Oil and NGL Reserves on Natural Gas and Oil Properties, Net

As described in Note 1 to the consolidated financial statements, the Company's consolidated natural gas and oil properties balance was $27,261 million as of December 31, 2020, and depreciation, depletion, and amortization (DD&A) expense for the year ended December 31, 2020 was $357 million. The Company utilizes the full cost method of accounting for its natural gas and oil properties. Under this method, all capitalized costs are amortized over the estimated lives of the properties using the unit-of-production method based on proved natural gas, oil and NGL reserves. These capitalized costs are subject to a quarterly ceiling test that limits such pooled costs, net of applicable deferred taxes, to the aggregate of the present value of future net revenues attributable to proved natural gas, oil and NGL reserves discounted at 10%. For the year ended December 31, 2020, pre-tax impairment charges of $2,825 million were recognized. As disclosed by management, proved natural gas, oil and NGL reserves are a major component of the full cost ceiling test. Estimates of reserves require extensive judgments of reservoir engineering data and projections of costs that will be incurred in developing and producing reserves. The uncertainties inherent in the reserve estimates are compounded by applying additional estimates of the rates and timing of future production volumes and the costs that will be incurred in developing and producing the reserves. The estimates of natural gas, oil and NGL reserves have been developed by specialists, specifically reservoir engineers, and audited by independent petroleum engineers (together referred to as "management's specialists").

The principal considerations for our determination that performing procedures relating to the impact of proved natural gas, oil and NGL reserves on natural gas and oil properties, net is a critical audit matter are (i) the significant judgment by management, including the use of management's specialists, when developing the estimates of proved natural gas, oil and NGL reserves, which in turn led to (ii) a high degree of auditor judgment, subjectivity and effort in performing procedures and evaluating audit evidence related to the data, methods, and assumptions used by management's specialists in developing the estimates of proved natural gas, oil and NGL reserves and the assumption applied to the full cost ceiling test calculations related to future production volumes.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's estimates of proved natural gas, oil and NGL reserves and the calculations of the full cost ceiling impairment test.

These procedures also included, among others, testing the full cost ceiling impairment test calculation. The work of management's specialists was used in performing the procedures to evaluate the reasonableness of the estimates of proved natural gas, oil and NGL reserves and the reasonableness of future production volumes applied in the full cost ceiling test. As a basis for using this work, management's specialists' qualifications were understood and the Company's relationship with the specialists was assessed. The procedures performed also included evaluation of the methods and assumptions used by management's specialists, tests of the data used by management's specialists, and an evaluation of management's specialists' findings.

Acquisition of Montage Resources – Valuation of Proved Natural Gas and Oil Properties

As described in Note 3 to the consolidated financial statements, $1,102 million of the purchase price from the November 2020 business combination of Montage Resources, Inc. was allocated to natural gas and oil properties, net, including $1,012 million related to proved properties. As disclosed by management, the Company accounts for business combinations under the acquisition method of accounting. Accordingly, the Company recognizes amounts for identifiable assets acquired and liabilities assumed equal to their estimated acquisition date fair values. Fair value of proved natural gas and oil properties as of the acquisition date was based on estimated proved natural gas, oil, and NGL reserves and related discounted net cash flows. Significant inputs to the valuation include estimates of future production volumes, future operating and development costs, future commodity prices and a weighted average cost of capital rate. Estimates of reserves require extensive judgments of reservoir engineering data and projections of costs will be incurred in developing and producing reserves. The uncertainties inherent in the reserve estimates are compounded by applying additional estimates of the rates and timing of future production volumes and the costs that will be incurred in developing and producing the reserves. The estimates of natural gas, oil and NGL reserves have been developed by specialists, specifically reservoir engineers, and audited by independent petroleum engineers (together referred to as "management's specialists").

The principal considerations for our determination that performing procedures relating to the acquisition of Montage Resources – valuation of proved natural gas and oil properties is a critical audit matter are the (i) significant judgment by management, including the use of management's specialists, when developing the fair value measurement of proved natural gas and oil properties; (ii) a high degree of auditor judgment, subjectivity and effort in performing procedures and evaluating management's significant assumptions related to future production volumes and commodity prices, as well as the weighted average cost of capital; and (iii) the audit effort involved the use of professionals with specialized skill and knowledge.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to the valuation of the acquired proved natural gas and oil properties. These procedures also included, among others (i) testing management's process for developing the fair value measurement of proved natural gas and oil properties; (ii) evaluating the appropriateness of the discounted cash flow model; (iii) testing the completeness and accuracy of underlying data used in the model; and (iv) evaluating the reasonableness of significant assumptions used by management related to future production volumes and commodity prices, as well as the weighted average cost of capital. Evaluating the reasonableness of management's assumption related to future commodity prices involved comparing the prices against observable market data and evaluating differentials through inspection of the underlying contracts. Professionals with specialized skill and knowledge were used to assist in the evaluation of reasonableness of the weighted average cost of capital assumption and the appropriateness of the discounted cash flow model. The work of management's specialists was used in performing the procedures to evaluate the reasonableness of the proved natural gas, oil and NGL reserve volumes as stated in the Critical Audit Matter titled "The Impact of Proved Natural Gas, Oil and NGL Reserves on Natural Gas and Oil Properties, Net" and the reasonableness of the future production volumes. As a basis for using this work, the specialists' qualifications were understood and the Company's relationship with the specialists was assessed. The procedures performed also included evaluation of the methods and assumptions used by the specialists, tests of the data used by the specialists and an evaluation of the specialists' findings.

/s/ PricewaterhouseCoopers LLP
Houston, Texas
March 1, 2021

We have served as the Company's auditor since 2002.

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions, except share/per share amounts)	For the years ended December 31, 2020	2019	2018
Operating Revenues:			
Gas sales	$ 967	$ 1,241	$ 1,998
Oil sales	154	223	196
NGL sales	265	274	352
Marketing	917	1,297	1,222
Gas gathering	—	—	89
Other	5	3	5
	2,308	3,038	3,862
Operating Costs and Expenses:			
Marketing purchases	946	1,320	1,229
Operating expenses	813	720	785
General and administrative expenses	121	166	209
Montage merger-related expenses	41	—	—
Restructuring charges	16	11	39
(Gain) loss on sale of operating assets	—	2	(17)
Depreciation, depletion and amortization	357	471	560
Impairments	2,830	16	171
Taxes, other than income taxes	55	62	89
	5,179	2,768	3,065
Operating Income (Loss)	(2,871)	270	797
Interest Expense:			
Interest on debt	171	166	231
Other interest charges	11	8	8
Interest capitalized	(88)	(109)	(115)
	94	65	124
Gain (Loss) on Derivatives	224	274	(118)
Gain (Loss) on Early Extinguishment of Debt	35	8	(17)
Other Income (Loss), Net	1	(7)	—
Income (Loss) Before Income Taxes	(2,705)	480	538
Provision (Benefit) for Income Taxes			
Current	(2)	(2)	1
Deferred	409	(409)	—
	407	(411)	1
Net Income (Loss)	$ (3,112)	$ 891	$ 537
Participating securities – mandatory convertible preferred stock	—	—	2
Net Income (Loss) Attributable to Common Stock	$ (3,112)	$ 891	$ 535
Earnings (Loss) Per Common Share			
Basic	$ (5.42)	$ 1.65	$ 0.93
Diluted	$ (5.42)	$ 1.65	$ 0.93
Weighted Average Common Shares Outstanding:			
Basic	573,889,502	539,345,343	574,631,756
Diluted	573,889,502	540,382,914	576,642,808

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	For the years ended December 31,		
(in millions)	2020	2019	2018 [(1)]
Net income (loss)	$ (3,112)	$ 891	$ 537
Change in value of pension and other postretirement liabilities:			
Amortization of prior service cost and net loss, including loss on settlements and curtailments included in net periodic pension cost [(2)]	3	8	10
Net actuarial loss incurred in period [(3)]	(8)	(5)	(2)
Total change in value of pension and postretirement liabilities	(5)	3	8
Comprehensive income (loss)	$ (3,117)	$ 894	$ 545

(1) In 2018, deferred tax activity incurred in other comprehensive income was offset by a valuation allowance.

(2) Net of $1 million and $2 million in taxes for the years ended December 31, 2020 and 2019, respectively.

(3) Net of ($2) million and ($1) million in taxes for the year ended December 31, 2020 and 2019, respectively.

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2020	December 31, 2019
ASSETS	*(in millions, except share amounts)*	
Current assets:		
Cash and cash equivalents	$ 13	$ 5
Accounts receivable, net	368	345
Derivative assets	241	278
Other current assets	49	51
Total current assets	671	679
Natural gas and oil properties, using the full cost method, including $1,472 million as of December 31, 2020 and $1,506 million as of December 31, 2019 excluded from amortization	27,261	25,250
Other	523	520
Less: Accumulated depreciation, depletion and amortization	(23,673)	(20,503)
Total property and equipment, net	4,111	5,267
Operating lease assets	163	159
Deferred tax assets	—	407
Other long-term assets	215	205
Total long-term assets	378	771
TOTAL ASSETS	$ 5,160	$ 6,717
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 573	$ 525
Taxes payable	74	59
Interest payable	58	51
Derivative liabilities	245	125
Current operating lease liabilities	42	34
Other current liabilities	20	54
Total current liabilities	1,012	848
Long-term debt	3,150	2,242
Long-term operating lease liabilities	117	119
Long-term derivative liabilities	183	111
Pension and other postretirement liabilities	45	43
Other long-term liabilities	156	108
Total long-term liabilities	3,651	2,623
Commitments and contingencies (Note 10)		
Equity:		
Common stock, $0.01 par value; 1,250,000,000 shares authorized; issued 718,795,700 shares as of December 31, 2020 and 585,555,923 as of December 31, 2019	7	6
Additional paid-in capital	5,093	4,726
Accumulated deficit	(4,363)	(1,251)
Accumulated other comprehensive loss	(38)	(33)
Common stock in treasury, 44,353,224 shares as of December 31, 2020 and 2019	(202)	(202)
Total equity	497	3,246
TOTAL LIABILITIES AND EQUITY	$ 5,160	$ 6,717

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the years ended December 31,		
(in millions)	2020	2019	2018
Cash Flows From Operating Activities:			
Net income (loss)	$ (3,112)	$ 891	$ 537
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	357	471	560
Amortization of debt issuance costs	9	8	8
Impairments	2,830	16	171
Deferred income taxes	409	(409)	—
(Gain) loss on derivatives, unsettled	138	(94)	24
Stock-based compensation	3	8	14
(Gain) loss on early extinguishment of debt	(35)	(8)	17
(Gain) loss on sale of assets	—	2	(17)
Other	6	10	(1)
Change in assets and liabilities:			
Accounts receivable	50	234	(153)
Accounts payable	(131)	(141)	65
Taxes payable	(7)	—	2
Interest payable	(11)	—	(10)
Inventories	2	(7)	(13)
Other assets and liabilities	20	(17)	19
Net cash provided by operating activities	528	964	1,223
Cash Flows From Investing Activities:			
Capital investments	(896)	(1,099)	(1,290)
Proceeds from sale of property and equipment	12	54	1,643
Cash acquired in Montage merger	3	—	—
Other	—	—	6
Net cash provided by (used in) investing activities	(881)	(1,045)	359
Cash Flows From Financing Activities:			
Payments on current portion of long-term debt	—	(52)	—
Payments on long-term debt	(72)	(54)	(2,095)
Payments on revolving credit facility	(1,671)	(532)	(1,983)
Borrowings under revolving credit facility	2,337	566	1,983
Change in bank drafts outstanding	1	(19)	17
Repayment of Montage revolving credit facility	(200)	—	—
Repayment of Montage senior notes	(522)	—	—
Proceeds from issuance of long-term debt	350	—	—
Debt issuance and other financing costs	(10)	(3)	(9)
Proceeds from issuance of common stock	152	—	—
Purchase of treasury stock	—	(21)	(180)
Preferred stock dividend	—	—	(27)
Cash paid for tax withholding	(4)	(1)	(3)
Other	—	1	—
Net cash provided by (used in) financing activities	361	(115)	(2,297)
Increase (decrease) in cash and cash equivalents	8	(196)	(715)
Cash and cash equivalents at beginning of year	5	201	916
Cash and cash equivalents at end of year	$ 13	$ 5	$ 201

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

	Common Stock		Preferred Stock				Common Stock in Treasury		
(in millions, except share amounts)	Shares Issued	Amount	Shares Issued	Additional Paid-In Capital	Accumulated Deficit	Accumulated Other Comprehensive Income (Loss)	Shares	Amount	**Total**
Balance at December 31, 2017	**512,134,311**	**$ 5**	**1,725,000**	**$ 4,698**	**$ (2,679)**	**$ (44)**	**31,269**	**$ (1)**	**$ 1,979**
Comprehensive income									
Net income	—	—	—	—	537	—	—	—	537
Other comprehensive income	—	—	—	—	—	8	—	—	8
Total comprehensive income	—	—	—	—	—	—	—	—	545
Stock-based compensation	—	—	—	21	—	—	—	—	21
Preferred stock dividend	74,998,614	1	(1,725,000)	(1)	—	—	—	—	—
Issuance of restricted stock	349,562	—	—	—	—	—	—	—	—
Cancellation of restricted stock	(1,804,122)	—	—	—	—	—	—	—	—
Performance units vested	214,866	—	—	—	—	—	—	—	—
Treasury stock	—	—	—	—	—	—	39,061,268	(180)	(180)
Tax withholding – stock compensation	(486,124)	—	—	(3)	—	—	—	—	(3)
Balance at December 31, 2018	**585,407,107**	**$ 6**	**—**	**$ 4,715**	**$ (2,142)**	**$ (36)**	**39,092,537**	**$ (181)**	**$ 2,362**
Comprehensive income									
Net income	—	—	—	—	891	—	—	—	891
Other comprehensive income	—	—	—	—	—	3	—	—	3
Total comprehensive income	—	—	—	—	—	—	—	—	894
Stock-based compensation	—	—	—	12	—	—	—	—	12
Issuance of restricted stock	236,978	—	—	—	—	—	—	—	—
Cancellation of restricted stock	(239,571)	—	—	—	—	—	—	—	—
Performance units vested	535,802	—	—	—	—	—	—	—	—
Treasury stock	—	—	—	—	—	—	5,260,687	(21)	(21)
Tax withholding – stock compensation	(384,393)	—	—	(1)	—	—	—	—	(1)
Balance at December 31, 2019	**585,555,923**	**$ 6**	**—**	**$ 4,726**	**$ (1,251)**	**$ (33)**	**44,353,224**	**$ (202)**	**$ 3,246**
Comprehensive loss									
Net loss	—	—	—	—	(3,112)	—	—	—	(3,112)
Other comprehensive loss	—	—	—	—	—	(5)	—	—	(5)
Total comprehensive loss	—	—	—	—	—	—	—	—	(3,117)
Stock-based compensation	—	—	—	4	—	—	—	—	4
Issuance of common stock	63,250,000	—	—	152	—	—	—	—	152
Issuance of restricted stock	311,446	—	—	—	—	—	—	—	—
Cancellation of restricted stock	(1,274,802)	—	—	—	—	—	—	—	—
Restricted units granted	2,697,170	—	—	3	—	—	—	—	3
Montage merger exchange	69,740,848	1	—	212	—	—	—	—	213
Tax withholding – stock compensation	(1,484,885)	—	—	(4)	—	—	—	—	(4)
Balance at December 31, 2020	**718,795,700**	**$ 7**	**—**	**$ 5,093**	**$ (4,363)**	**$ (38)**	**44,353,224**	**$ (202)**	**$ 497**

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations

Southwestern Energy Company (including its subsidiaries, collectively "Southwestern" or the "Company") is an independent energy company engaged in natural gas, oil and NGLs exploration, development and production ("E&P"). The Company is also focused on creating and capturing additional value through its marketing business ("Marketing"), which was previously referred to as "Midstream" when it included the operations of gathering systems. Southwestern conducts most of its business through subsidiaries and operates principally in two segments: E&P and Marketing.

E&P. Southwestern's primary business is the exploration for and production of natural gas, oil and NGLs, with ongoing operations focused on the development of unconventional natural gas and oil reservoirs located in Pennsylvania, Ohio and West Virginia. The Company's operations in northeast Pennsylvania, herein referred to as "Northeast Appalachia," are primarily focused on the unconventional natural gas reservoir known as the Marcellus Shale. Operations in West Virginia, Ohio and southwest Pennsylvania, herein referred to as "Southwest Appalachia," are focused on the Marcellus Shale, the Utica and the Upper Devonian unconventional natural gas and oil reservoirs. Collectively, Southwestern refers to its properties located in Pennsylvania, Ohio and West Virginia as "Appalachia." The Company also operates drilling rigs located in Appalachia, and provides oilfield products and services, principally serving the Company's E&P operations through vertical integration.

In August 2020, the Company entered into an Agreement and Plan of Merger (the "Merger Agreement") with Montage Resources Corporation ("Montage") pursuant to which Montage will merge with and into Southwestern, with Southwestern continuing as the surviving company (the "Merger"). The Company acquired at the effective time of the merger all of the outstanding shares of common stock in Montage in exchange for 1.8656 shares of Southwestern common stock per share of Montage common stock. The transaction closed on November 13, 2020. The Merger expanded the Company's footprint in Appalachia by supplementing the Northeast Appalachia and Southwest Appalachia operations and by expanding the Company's operations into Ohio. See Note 3 for more information about the Merger.

Marketing. Southwestern's marketing activities capture opportunities that arise through the marketing and transportation of natural gas, oil and NGLs primarily produced in its E&P operations.

Basis of Presentation

The consolidated financial statements included in this Annual Report present the Company's financial position, results of operations and cash flows for the periods presented in accordance with accounting principles generally accepted in the United States ("GAAP"). The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the financial statements, and the amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. The Company evaluates subsequent events through the date the financial statements are issued.

Principles of Consolidation

The consolidated financial statements include the accounts of Southwestern and its wholly-owned subsidiaries. All significant intercompany accounts and transactions have been eliminated.

In 2015, the Company purchased an 86% ownership in a limited partnership that owns and operates a gathering system in Northeast Appalachia. Because the Company owns a controlling interest in the partnership, the operating and financial results are consolidated with the Company's E&P segment results. The minority partner's share of the partnership activity is reported in retained earnings in the consolidated financial statements. Net income attributable to noncontrolling interest for the years ended December 31, 2020, 2019 and 2018 was insignificant.

Major Customers

The Company sells the vast majority of its E&P natural gas, oil and NGL production to third-party customers through its marketing subsidiary. Customers include major energy companies, utilities and industrial purchasers of Natural gas. For the year ended December 31, 2020, one purchaser accounted for 10% of total revenues. A default on this account could have a material impact on the Company, but the Company does not believe that there is a material risk of default. No other purchasers accounted for greater than 10% of consolidated revenues. For the year ended December 31, 2019, no single customer accounted for 10% or greater of total sales. The Company believes that the loss of any one customer would not have an adverse effect on its ability to sell its natural gas, oil and NGL production.

Cash and Cash Equivalents

Cash and cash equivalents are defined by the Company as short-term, highly liquid investments that have an original maturity of three months or less and deposits in money market mutual funds that are readily convertible into cash. Management considers cash and cash equivalents to have minimal credit and market risk as the Company monitors the credit status of the financial institutions holding its cash and marketable securities. The following table presents a summary of cash and cash equivalents as of December 31, 2020, and December 31, 2019:

(in millions)	December 31, 2020	December 31, 2019
Cash	$ 13	$ 5
Marketable securities (1)	—	—
Total	$ 13	$ 5

(1) Consists of government stable value money market funds. Immaterial as of December 31, 2020 and 2019.

Certain of the Company's cash accounts are zero-balance controlled disbursement accounts. The Company presents the outstanding checks written against these zero-balance accounts as a component of accounts payable in the accompanying consolidated balance sheets. Outstanding checks included as a component of accounts payable totaled $16 million and $15 million as of December 31, 2020 and 2019, respectively.

Property, Depreciation, Depletion and Amortization

Natural Gas and Oil Properties. The Company utilizes the full cost method of accounting for costs related to the exploration, development and acquisition of natural gas and oil properties. Under this method, all such costs (productive and nonproductive), including salaries, benefits and other internal costs directly attributable to these activities, are capitalized on a country-by-country basis and amortized over the estimated lives of the properties using the units-of-production method. These capitalized costs are subject to a ceiling test that limits such pooled costs, net of applicable deferred taxes, to the aggregate of the present value of future net revenues attributable to proved natural gas, oil and NGL reserves discounted at 10% (standardized measure). Any costs in excess of the ceiling are written off as a non-cash expense. The expense may not be reversed in future periods, even though higher natural gas, oil and NGL prices may subsequently increase the ceiling. Companies using the full cost method are required to use the average quoted price from the first day of each month from the previous 12 months, including the impact of derivatives designated for hedge accounting, to calculate the ceiling value of their reserves. Decreases in market prices as well as changes in production rates, levels of reserves, evaluation of costs excluded from amortization, future development costs and production costs could result in future ceiling test impairments.

Costs associated with unevaluated properties are excluded from the amortization base until the properties are evaluated or impairment is indicated. The costs associated with unevaluated leasehold acreage and related seismic data, wells currently drilling and related capitalized interest are initially excluded from the amortization base. Leasehold costs are either transferred to the amortization base with the costs of drilling a well on the lease or are assessed at least annually for possible impairment or reduction in value. The Company's decision to withhold costs from amortization and the timing of the transfer of those costs into the amortization base involves judgment and may be subject to changes over time based on several factors, including drilling plans, availability of capital, project economics and drilling results from adjacent acreage. At December 31, 2020, the Company had a total of $1,472 million of costs excluded from the amortization base, all of which related to its properties in the United States. Inclusion of some or all of these costs in the Company's United States properties in the future, without adding any associated reserves, could result in additional non-cash ceiling test impairments.

In the first, second and third quarters of 2020, the net book value of the Company's United States natural gas and oil properties exceeded the ceiling by approximately $1,479 million, $650 million and $361 million, respectively, and resulted in non-cash ceiling test impairments. At December 31, 2020, using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $1.98 per MMBtu, West Texas Intermediate oil of $39.57 per barrel and NGLs of $10.27 per barrel, adjusted for market differentials, the Company's net book value of its United States natural gas and oil properties exceeded the ceiling by approximately $335 million and resulted in an additional non-cash ceiling test impairment. The Company had no derivative positions that were designated for hedge accounting as of December 31, 2020.

No impairment expense was recorded for the year ended December 31, 2020 in relation to the Company's recently acquired Montage natural gas and oil properties. These properties were recorded at fair value as of November 13, 2020, in accordance with ASC 820 *Fair Value Measurement*. Pursuant to SEC guidance, the Company determined that the fair value of the properties acquired at the closing of the Merger clearly exceeded the related full-cost ceiling limitation beyond a reasonable doubt and received a waiver from the SEC to exclude the properties acquired in the Merger from the ceiling test calculation. This waiver was granted for all reporting periods through and including the quarter ending September 30, 2021 as long as the Company can continue to demonstrate that the fair value of properties acquired clearly exceeds the full cost ceiling limitation beyond a reasonable doubt in each reporting period. As part of the waiver received from the SEC, the Company is required to disclose what the full cost ceiling test impairment amounts for all periods presented in each applicable quarterly and annual filing would have been if the waiver had not been granted. The fair value of the properties acquired in the Merger was based on forward strip natural gas and oil pricing existing at the date of the Merger, and management affirmed that there has not been a material decline to the fair value of these acquired assets since the Merger. The properties acquired in the Merger have an unamortized cost at December 31, 2020 of $1,087 million. Had management not received the waiver from the SEC, the impairment charge recorded would have been an additional $539 million for the year ended December 31, 2020.

Using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $2.58 per MMBtu, West Texas Intermediate oil of $55.69 per barrel and NGLs of $11.58 per barrel, adjusted for market differentials, the Company's net book value of its United States natural gas and oil properties did not exceed the ceiling amount and did not result in a ceiling test impairment at December 31, 2019. The Company had no derivative positions that were designated for hedge accounting as of December 31, 2019.

Using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $3.10 per MMBtu, West Texas Intermediate oil of $65.56 per barrel and NGLs of $17.64 per barrel, adjusted for market differentials, the Company's net book value of its United States natural gas and oil properties did not exceed the ceiling amount and did not results in a ceiling test impairment at December 31, 2018. The Company had no derivative positions that were designated for hedge accounting as of December 31, 2018.

Capitalized Interest. Interest is capitalized on the cost of unevaluated natural gas and oil properties that are excluded from amortization.

Asset Retirement Obligations. Natural gas and oil properties require expenditures to plug and abandon the wells and reclaim the associated pads and other supporting infrastructure when the wells are no longer producing. An asset retirement obligation associated with the retirement of a tangible long-lived asset such as oil and gas properties is recognized as a liability in the period incurred or when it becomes determinable, with an associated increase in the carrying amount of the related long-lived asset. The cost of the tangible asset, including the asset retirement cost, is depreciated over the useful life of the asset. The asset retirement obligation is recorded at its estimated fair value, and accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value.

Other Property and Equipment. The Company's non-full cost pool assets include water facilities, gathering systems, technology infrastructure, land, buildings and other equipment with useful lives that range from 3 to 30 years.

The estimated useful lives of those assets depreciated under the straight-line method are as follows:

Water facilities	5 – 10 years
Gathering systems	15 – 25 years
Technology infrastructure	3 – 7 years
Drilling rigs and equipment	3 years
Buildings and leasehold improvements	10 – 30 years

Other property, plant and equipment is comprised of the following:

(in millions)	December 31, 2020	December 31, 2019
Water facilities	$ 228	$ 217
Gathering systems	54	32
Technology infrastructure	133	154
Drilling rigs and equipment	26	32
Land, buildings and leasehold improvements	41	41
Other	41	44
Less: Accumulated depreciation and impairment	(311)	(300)
Total	$ 212	$ 220

Impairment of Long-Lived Assets. The carrying value of non-full cost pool long-lived assets is evaluated for recoverability whenever events or changes in circumstances indicate that it may not be recoverable. Should an impairment exist, the impairment loss would be measured as the amount that the asset's carrying value exceeds its fair value. For the years ended December 31, 2020 and 2019 the Company recognized non-cash impairments of $5 million and $16 million, respectively, for non-core assets. During 2018, the Company recognized a non-cash impairment charge of $160 million related to gathering and other E&P assets sold in the Fayetteville Shale sale and $11 million related to other non-core assets.

Intangible Assets. The carrying value of intangible assets are evaluated for recoverability whenever events or changes in circumstances indicate that it may not be recoverable. Intangible assets are amortized over their useful life. At December 31, 2020 and 2019, the Company had $48 million and $56 million, respectively, in marketing-related intangible assets that were included in Other long-term assets on the consolidated balance sheets. The Company amortized $9 million of its marketing-related intangible asset in each of the years ended December 31, 2020, 2019 and 2018, and expects to amortize $8 million in 2021 and $5 million per year for the four years thereafter.

Leases

The Company determines if a contract contains a lease at inception or as a result of an acquisition. A lease is defined as a contract, or part of a contract, that conveys the right to control the use of identified property, plant or equipment (an identified asset) for a period of time in exchange for consideration. A right-of-use asset and corresponding lease liability are recognized on the balance sheet at commencement at an amount based on the present value of the remaining lease payments over the lease term. As the implicit rate of the lease is not always readily determinable, the Company uses the incremental borrowing rate to calculate the present value of the lease payments based on information available at commencement date, such as the initial lease term. Operating right-of-use assets and operating lease liabilities are presented separately on the consolidated balance sheet. The Company does not have any finance leases as of December 31, 2020. By policy election, leases with an initial term of twelve months or less are not recorded on the balance sheet. The Company recognizes lease expense for these leases on a straight-line basis, and variable lease payments are recognized in the period as incurred.

Certain leases contain both lease and non-lease components. The Company has chosen to account for most of these leases as a single lease component instead of bifurcating lease and non-lease components. However, for compression service leases and fleet vehicle leases, the lease and non-lease components are accounted for separately.

The Company leases drilling rigs, pressure pumping equipment, vehicles, office space, certain water transportation lines and other equipment under non-cancelable operating leases expiring through 2036. Certain lease agreements include options to renew the lease, early terminate the lease or purchase the underlying asset(s). The Company determines the lease term at the lease commencement date as the non-cancelable period of the lease, including options to extend or terminate the lease when such an option is reasonably certain to be exercised. The Company's water transportation lines are the only leases with renewal options that are reasonably certain to be exercised. These renewal options are reflected in the right-of-use asset and lease liability balances.

Income Taxes

The Company follows the asset and liability method of accounting for income taxes. Under this method, deferred tax assets and liabilities are recorded for the estimated future tax consequences attributable to the differences between the financial carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using the tax rate expected to be in effect for the year in which those temporary differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in the year of the enacted rate change. Deferred income taxes are provided to recognize the income tax effect of reporting certain transactions in different years for income tax and financial reporting purposes. A valuation allowance for deferred tax assets, including net operating losses, is recognized when it is more likely than not that some or all of the benefit from the deferred tax assets will not be realized.

The Company accounts for uncertainty in income taxes using a recognition and measurement threshold for tax positions taken or expected to be taken in a tax return. The tax benefit from an uncertain tax position is recognized when it is more likely than not that the position will be sustained upon examination by taxing authorities based on technical merits of the position. The amount of the tax benefit recognized is the largest amount of the benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. The effective tax rate and the tax basis of assets and liabilities reflect management's estimates of the ultimate outcome of various tax uncertainties. The Company recognizes penalties and interest related to uncertain tax positions within the provision (benefit) for income taxes line in the accompanying consolidated statements of operations. Additional information regarding uncertain tax positions along with the impact of the Tax Reform Act can be found in Note 11.

Derivative Financial Instruments

The Company uses derivative financial instruments to manage defined commodity price risks and does not use them for speculative trading purposes. The Company uses derivative instruments to financially protect sales of natural gas, oil and NGLs. In addition, the Company uses interest rate swaps to manage exposure to unfavorable interest rate changes. Since the Company does not designate its derivatives for hedge accounting treatment, gains and losses resulting from the settlement of derivative contracts have been recognized in gain (loss) on derivatives in the consolidated statements of operations when the contracts expire and the related physical transactions of the underlying commodity are settled. Additionally, changes in the fair value of the unsettled portion of derivative contracts are also recognized in gain (loss) on derivatives in the consolidated statement of operations. See Note 6 and Note 8 for a discussion of the Company's hedging activities.

Earnings Per Share

Basic earnings per common share is computed by dividing net income (loss) attributable to common stock by the weighted average number of common shares outstanding during the reportable period. The diluted earnings per share calculation adds to the weighted average number of common shares outstanding: the incremental shares that would have been outstanding assuming the exercise of dilutive stock options, the vesting of unvested restricted shares of common stock, restricted stock units and performance units. An antidilutive impact is an increase in earnings per share or a reduction in net loss per share resulting from the conversion, exercise, or contingent issuance of certain securities.

In August 2020, the Company completed an underwritten public offering of 63,250,000 shares of its common stock with an offering price to the public of $2.50 per share. Net proceeds after deducting underwriting discounts and offering expenses were approximately $152 million. See Note 3 for additional details regarding the Company's use of proceeds from the equity offering.

Under the Agreement and Plan of Merger, Montage shareholders received 1.8656 shares of Southwestern common stock for each share of Montage common stock issued and outstanding immediately prior to the date of Merger. On November 13, 2020, the Company issued 69,740,848 shares of its common stock, or approximately $213 million in value (based on Southwestern common stock closing price as of November 13, 2020 of $3.05), as Merger consideration.

In January 2015, the Company issued 34,500,000 depositary shares that entitled the holder to a proportional fractional interest in the rights and preferences of the mandatory convertible preferred stock, including conversion, dividend, liquidation and voting rights. The mandatory convertible preferred stock had the non-forfeitable right to participate on an as-converted basis at the conversion rate then in effect in any common stock dividends declared and, therefore, was considered a participating security. Accordingly, it has been included in the computation of basic and diluted earnings per share, pursuant to the two-class method. In the calculation of basic earnings per share attributable to common shareholders, earnings are allocated to participating securities based on actual dividend distributions received plus a proportionate share of undistributed net income attributable to common shareholders, if any, after recognizing distributed earnings. The Company's participating securities do not participate in undistributed net losses because they are not contractually obligated to do so. In January 2018, all outstanding shares of mandatory convertible preferred stock were converted to 74,998,614 shares of the Company's common stock. The Company paid its last dividend payment of approximately $27 million associated with the depositary shares in January 2018.

As part of the Company's share repurchase program, the Company paid approximately $180 million to repurchase 39,061,268 shares of its outstanding common stock in 2018 and paid approximately $21 million to repurchase 5,260,687 shares in 2019, which are included in the Company's treasury stock.

The following table presents the computation of earnings per share for the years ended December 31, 2020, 2019 and 2018:

	For the years ended December 31,		
(in millions, except share/per share amounts)	2020	2019	2018
Net income (loss)	$ (3,112)	$ 891	$ 537
Participating securities – mandatory convertible preferred stock	—	—	2
Net income (loss) attributable to common stock	$ (3,112)	$ 891	$ 535
Number of common shares:			
Weighted average outstanding	573,889,502	539,345,343	574,631,756
Issued upon assumed exercise of outstanding stock options	—	—	—
Effect of issuance of non-vested restricted common stock	—	361,380	698,103
Effect of issuance of non-vested restricted units	—	—	—
Effect of issuance of non-vested performance units	—	676,191	1,312,949
Weighted average and potential dilutive outstanding	573,889,502	540,382,914	576,642,808
Earnings (loss) per common share:			
Basic	$ (5.42)	$ 1.65	$ 0.93
Diluted	$ (5.42)	$ 1.65	$ 0.93

The following table presents the common stock shares equivalent excluded from the calculation of diluted earnings per share for the years ended December 31, 2020, 2019 and 2018, as they would have had an antidilutive effect:

	For the years ended December 31,		
	2020	2019	2018
Unexercised stock options	4,427,040	5,078,253	5,909,082
Unvested share-based payment	962,662	1,728,264	3,692,794
Restricted units	4,452,876	—	—
Performance units	2,818,653	271,268	642,568
Mandatory convertible preferred stock	—	—	2,465,708
Total	12,661,231	7,077,785	12,710,152

Supplemental Disclosures of Cash Flow Information

The following table provides additional information concerning interest and income taxes paid as well as changes in noncash investing activities for the years ended December 31, 2020, 2019 and 2018:

	For the years ended December 31,		
(in millions)	2020	2019	2018
Cash paid during the year for interest, net of amounts capitalized	$ 75	$ 58	$ 135
Cash paid (received) during the year for income taxes	(32)	(52)	6
Increase (decrease) in noncash property additions	1,084 (1)	41	(42)

(1) Includes $1,097 million in noncash additions related to the Montage Merger.

Stock-Based Compensation

The Company accounts for stock-based compensation transactions using a fair value method and recognizes an amount equal to the fair value of the stock options and stock-based payment cost in either the consolidated statement of operations and capitalizes the cost into natural gas and oil properties included in property and equipment. Costs are capitalized when they are directly related to the acquisition, exploration and development activities of the Company's natural gas and oil properties. See Note 14 for a discussion of the Company's stock-based compensation.

Liability-Classified Awards

The Company classifies certain awards that can or will be settled in cash as liability awards. The fair value of a liability-classified award is determined on a quarterly basis beginning at the grant date until final vesting. Changes in the fair value of liability-classified awards are recorded to general and administrative expense, operating expense and capitalized expense over the vesting period of the award. The Company's liability-classified performance unit awards that were granted in 2018 include a performance condition based on cash flow per debt-adjusted share and two market conditions, one based on absolute total shareholder return ("TSR") and the other on relative TSR as compared to a group of the Company's peers. The Company's liability-classified performance unit awards that were granted in 2019 include a performance condition based on the return of average capital employed and the same two market conditions as in the 2018 awards. The liability-based performance unit awards granted in 2020 include a performance condition based on return on average capital employed and a market condition based on relative TSR. The fair values of the market conditions discussed above are calculated by Monte Carlo models on a quarterly basis. See Note 14 for a discussion of the Company's stock-based compensation.

Cash-Based Compensation

The Company classifies certain awards that will be settled in cash as cash-based compensation. The Company recognizes the cost of these awards as general and administrative expense, operating expense and capitalized expense over the vesting period of the awards. The performance cash awards include a performance condition determined annually by the Company. If the Company, in its sole discretion, determines that the threshold was not met, the amount for that vesting period will not vest and will be canceled.

Treasury Stock

In 2018, the Company repurchased 39,061,268 shares of its outstanding common stock per a previously announced share repurchase program at an average price of $4.63 per share for approximately $180 million. In 2019, the Company completed its share repurchase program by purchasing another 5,260,687 shares of its outstanding common stock for approximately $21 million at an average price of $3.84 per share.

The Company maintains a frozen legacy non-qualified deferred compensation supplemental retirement savings plan for certain key employees whereby participants could elect to defer and contribute a portion of their compensation to a Rabbi Trust, as permitted by the plan. The Company includes the assets and liabilities of its supplemental retirement savings plan in its consolidated balance sheet. Shares of the Company's common stock purchased under the non-qualified deferred compensation arrangement are held in the Rabbi Trust, are presented as treasury stock and are carried at cost. As of December 31, 2020 and 2019, 3,632 shares and 5,115 shares, respectively, were held in the Rabbi Trust and were accounted for as treasury stock.

Foreign Currency Translation

The Company has designated the Canadian dollar as the functional currency for its activities in Canada. The cumulative translation effects of translating the accounts from the functional currency into the U.S. dollar at current exchange rates are included as a separate component of other comprehensive income within stockholders' equity.

New Accounting Standards Implemented in this Report

In August 2018, the FASB issued Accounting Standards Update No. 2018-13, Fair Value Management (ASC 820): Disclosure Framework – Changes to the Disclosure Requirements for Fair Value Measurements ("ASU 2018-13"), which modifies the disclosure requirements on fair value measurements. ASU 2018-13 became effective for public business entities for annual and interim periods in the fiscal years beginning after December 15, 2019. As a result of this adoption, this standard did not have a material impact on the Company's consolidated financial statements.

In June 2016, the FASB issued Accounting Standards Update No. 2016-13, Financial Instruments – Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments ("Update 2016-13"). Update 2016-13 replaced the incurred loss model with an expected loss model, which is referred to as the current expected credit loss ("CECL") model. The CECL model is applicable to the measurement of credit losses on financial assets measured at amortized cost, including but not limited to trade receivables. For public business entities, the new standard became effective for annual reporting periods beginning after December 15, 2019, including interim periods within that reporting period.

From an evaluation of the Company's existing and recently acquired credit portfolios, which include trade receivables from commodity sales, joint interest billings due from partners and other receivables and cash equivalents, historical credit losses have been de minimis and are expected to remain so in the future assuming no substantial changes to the business or creditworthiness of our business counterparties. Update 2016-13 did not have a significant impact on the Company's consolidated financial statements or related control environment upon adoption on January 1, 2020.

New Accounting Standards Not Yet Adopted in this Report

In August 2018, the FASB issued ASU 2018-14, Disclosure Framework – Changes to the Disclosure Requirements for Defined Benefit Plans ("ASU 2018-14"). This ASU amends, adds and removes certain disclosure requirements under FASB ASC Topic 715 – Compensation – Retirement Benefits. The guidance in ASU 2018-14 is effective for fiscal years beginning after December 15, 2020, with early adoption permitted. This ASU will result in expanded disclosures within the Company's interim and annual footnote disclosures, however, the adoption of ASU 2018 is not expected to have a material impact on the Company's consolidated financial statements.

In March 2020, the FASB issued ASU 2020-04, Reference Rate Reform, as a new Accounting Standards Codification ("ASC") Topic, ASC 848. The purpose of ASC 848 is to provide optional guidance to ease the potential effects on financial reporting of the market-wide migration away from Interbank Offered Rates, such as LIBOR, which is expected to be phased out at the end of calendar year 2021, to alternative reference rates. ASC 848 applies only to contracts, hedging relationships, debt arrangements and other transactions that reference a benchmark reference rate expected to be discontinued because of reference rate reform. ASC 848 contains optional expedients and exceptions for applying U.S. GAAP to transactions affected by this reform. The amendments in the ASU are effective for all entities as of March 12, 2020 through December 31, 2022. The Company is currently assessing the impact of adopting this new guidance.

(2) RESTRUCTURING CHARGES

As part of an ongoing strategic effort to reposition its portfolio, optimize operational performance and improve margins, the Company has incurred charges related to restructuring that include reductions in workforce, office consolidation and other costs, including those associated with the sale of a large asset such as the Fayetteville Shale. These charges are further discussed below. The following table presents a summary of the restructuring charges included in Operating Income for the years ended December 31, 2020, 2019 and 2018:

	For the years ended December 31,		
(in millions)	2020	2019	2018 (1)
Reduction in workforce (not Fayetteville Shale sale-related)	$ 16	$ —	$ 23
Fayetteville Shale sale-related	—	11	16
Total restructuring charges	$ 16	$ 11	$ 39

(1) Does not include a $4 million gain for the year ended December 31, 2018 related to curtailment of the other postretirement benefit plan presented in other income (loss), net on the consolidated statements of operations.

The following table presents a summary of liabilities associated with the Company's restructuring activities at December 31, 2020, which are reflected in accounts payable on the consolidated balance sheet:

(in millions)	
Liability at December 31, 2019	$ 2
Additions	16
Distributions	(15)
Liability at December 31, 2020	**$ 3**

Reduction in Workforce (Not Fayetteville Shale Sale-Related)

In February 2020, the Company notified employees of a workforce reduction plan as a result of a strategic realignment of the Company's organizational structure. This reduction was substantially complete by the end of the first quarter of 2020. Affected employees were offered a severance package, which included a one-time payment depending on length of service and, if applicable, the current value of unvested long-term incentive awards that were forfeited. These costs were recognized as restructuring charges for the year ended December 31, 2020. The Company also recognized additional severance costs in the fourth quarter of 2020 related to continued organizational restructuring for which a liability of $3 million has been accrued as of December 31, 2020.

In June 2018, the Company notified affected employees of a workforce reduction plan, which resulted primarily from a previously announced study of structural, process and organizational changes to enhance shareholder value and continues with respect to other aspects of the Company's business activities. Affected employees were offered a severance package, which included a one-time cash payment depending on length of service and, if applicable, the current value of a portion of equity awards that were forfeited.

The following table presents a summary of the restructuring charges related to workforce reduction plans included in Operating Income (Loss) for the year ended December 31, 2020, 2019 and 2018:

	For the years ended December 31,		
(in millions)	2020	2019	2018
Severance (including payroll taxes)	$ 16	$ —	$ 21
Outplacement services, other	—	—	2
Total reduction in workforce-related restructuring charges (1)	$ 16	$ —	$ 23

(1) Total restructuring charges were $16 million for the Company's E&P segment for the year ended December 31, 2020. Total restructuring charges for the Company's E&P and Marketing segments were $21 million and $2 million, respectively, for the year ended December 31, 2018.

Fayetteville Shale Sale-Related

In December 2018, the Company closed on the sale of the equity in certain of its subsidiaries that owned and operated its Fayetteville Shale E&P and related midstream gathering assets in Arkansas. As part of this transaction, most employees associated with those assets became employees of the buyer although the employment of some was terminated. All affected employees were offered a severance package, which included a one-time cash payment depending on length of service and, if applicable, the current value of a portion of equity awards that were forfeited. The Company had substantially completed the Fayetteville Shale sale-related employment terminations by December 31, 2019.

As a result of the Fayetteville Shale sale, the Company relocated certain employees and infrastructure to other locations and began the process of consolidating and reorganizing its office space. Approximately $2 million in charges related to office consolidation and reorganization were recognized as restructuring charges.

In July 2019, the Company terminated its existing lease agreement in its headquarters office building and entered into a new 10-year lease agreement for a smaller portion of the building. Approximately $3 million of the fees associated with the Company’s headquarters office consolidation and $1 million in other office consolidation expenses are reflected as restructuring charges for the year ended December 31, 2019. The Company also recognized additional severance costs in the third and fourth quarters of 2019, related to continued organizational restructuring. The following table presents a summary of the restructuring charges related to the consolidation and reorganization associated with the Fayetteville Shale sale included in Operating Income on the condensed statements of operations for the years ended December 31, 2019 and 2018:

	For the years ended December 31,	
(in millions)	2019	2018
Severance (including payroll taxes)	$ 5	$ 12
Office consolidation	6	4
Total Fayetteville Shale sale-related charges (1) (2)	$ 11	$ 16

(1) Total restructuring charges were $11 million and $16 million for the Company’s E&P segment for the years ended December 31, 2019 and 2018, respectively.

(2) Does not include a $4 million gain for the year ended December 31, 2018 related to the curtailment of the other postretirement benefit plan presented in Other Income (Loss), net on the consolidated statements of operations.

See Note 3 for a discussion of the Company’s Fayetteville Shale sale.

(3) ACQUISITIONS AND DIVESTITURES

Montage Resources Merger

On August 12, 2020, Southwestern entered into an Agreement and Plan of Merger with Montage Resources Corporation (“Montage”) whereby Montage would merge with and into Southwestern, with Southwestern continuing as the surviving company (the "Merger"). On November 12, 2020, Montage’s stockholders voted to approve the Merger and it was made effective on November 13, 2020. The Merger added to Southwestern’s oil and gas portfolio in Appalachia.

In exchange for each share of Montage common stock, Montage stockholders received 1.8656 shares of Southwestern common stock, plus cash in lieu of any fractional share of Southwestern common stock that otherwise would have been issued, based on the average price of $3.05 per share of Southwestern common stock on the NYSE on November 13, 2020. Following the closing of the Merger, Southwestern's existing shareholders and Montage's existing shareholders owned approximately 90% and 10%, respectively, of the outstanding shares of the combined company.

In anticipation of the Merger, in August 2020 Southwestern issued $350 million of new senior unsecured notes and 63,250,000 shares of common stock for $152 million after deducting underwriting discounts and offering expenses. The

Company used the net proceeds from the debt and common stock offerings and borrowings under its revolving credit facility to fund a redemption of $510 million aggregate principal amount of Montage's outstanding 8.875% senior notes due 2023 (the "Montage Notes") and related accrued interest in connection with the closing of the Merger. See Note 1 and Note 9 for additional information.

The Merger constitutes a business combination and was accounted for using the acquisition method of accounting. The following table presents the fair value of consideration transferred to Montage stockholders as a result of the Merger:

(in millions, except share, per share amounts)	As of November 13, 2020	
Shares of Southwestern common stock issued in respect of outstanding Montage common stock		67,311,166
Shares of Southwestern common stock issued in respect of Montage stock-based awards		2,429,682
		69,740,848
NYSE closing price per share of Southwestern common shares on November 13, 2020	$	3.05
Total consideration (fair value of Southwestern common shares issued)	$	213
Increase in Southwestern common stock ($0.01 par value per share)		1
Increase in Southwestern additional paid-in capital	$	212

The following table sets forth the fair value of the assets acquired and liabilities assumed as of the acquisition date. Although the purchase price allocation is substantially complete as of the date of this filing, there may be further adjustments to the Company's natural gas and oil properties. These amounts will be finalized no later than one year from the acquisition date.

(in millions)	As of November 13, 2020	
Consideration:		
Fair value of Southwestern's stock issued on November 13, 2020	$	213
Fair value of assets acquired:		
Cash and cash equivalents		3
Accounts receivable		73
Other current assets		1
Derivative assets		11
Evaluated natural gas and oil properties		1,012
Unevaluated natural gas and oil properties		90
Other property, plant and equipment		28
Other long-term assets		26
Total assets acquired		1,244
Fair value of liabilities assumed:		
Accounts payable		145
Other current liabilities		49
Derivative liabilities		70
Revolving credit facility		200
Senior unsecured notes		522
Asset retirement obligations		28
Other long-term liabilities		17
Total liabilities assumed		1,031
Net assets acquired and liabilities assumed	$	213

The assets acquired and liabilities assumed were recorded at their preliminary estimated fair values at the date of the Merger. The valuation of certain assets, including property, are based on preliminary appraisals. The fair value of acquired equipment is based on both available market data and a cost approach.

Unevaluated oil and gas properties were valued primarily using a market approach based on comparable transactions for similar properties while the income approach was utilized for proved oil and gas properties based on underlying reserve projections at the Merger date. Income approaches are considered Level 3 fair value estimates and include significant assumptions of future production, commodity prices, and operating and capital cost estimates, discounted using weighted average cost of capital for industry peers, and risk adjustment factors based on reserve category. Price assumptions were based on observable market pricing adjusted for historical differentials. Cost estimates were based on current observable costs inflated based on historical and expected future inflation. Taxes were based on current statutory rates.

Deferred income taxes represent the tax effects of differences in the tax basis and merger-date fair values of assets acquired and liabilities assumed. A full valuation was placed on all deferred tax assets assumed from Montage consistent with the Company's treatment of its deferred tax asset balance as of December 31, 2020. The measurement of senior unsecured notes was based on unadjusted quoted prices in an active market and are primarily Level 1. The Company considered the borrowings under the revolving credit facility to approximate fair value. The value of derivative instruments was based on observable inputs, primarily forward commodity-price and interest-rate curves and is considered Level 2.

With the completion of the Merger, Southwestern acquired proved and unproved properties of approximately $1.0 billion and $90 million, respectively, primarily associated with the Appalachian Basin. The remaining $28 million in Other property, plant and equipment consists of a gathering system, buildings and various equipment.

From the date of the Merger through December 31, 2020, revenues and the net income attributable to common stockholders associated with the operations acquired through the Merger totaled $63 million and $28 million, respectively.

The following table summarizes the unaudited pro forma condensed financial information of Southwestern as if the Merger had occurred on January 1, 2019:

	For the years ended December 31,	
(in millions, except per share amounts)	2020	2019
Revenues	$ 2,701	$ 3,673
Net income (loss) attributable to common stock	$ (3,177)	$ 995
Net income (loss) attributable to common stock per share – basic	$ (4.71)	$ 1.48
Net income (loss) attributable to common stock per share – diluted	$ (4.71)	$ 1.48

The unaudited pro forma information is not necessarily indicative of the operating results that would have occurred had the Merger been completed at January 1, 2019, nor is it necessarily indicative of future operating results of the combined entity. The unaudited pro forma information gives effect to the Merger and related equity and debt issuances along with the use of proceeds therefrom as if they had occurred on January 1, 2019. The unaudited pro forma information for 2020 and 2019 is a result of combining the statements of operations of Southwestern with the pre-Merger results from January 1, 2020, and 2019 of Montage and included adjustments for revenues and direct expenses. The pro forma results exclude any cost savings anticipated as a result of the Merger and the impact of any Merger-related costs. The pro forma results include adjustments to DD&A (depreciation, depletion and amortization) based on the purchase price allocated to property, plant, and equipment and the estimated useful lives as well as adjustments to interest expense. Interest expense was adjusted to reflect the retirement of the Montage senior notes, the Montage credit facility, all related accrued interest and the associated decrease in amortization of issuance costs related to the Montage notes and revolving line of credit. This decrease was partially offset by increases in interest on debt associated with the issuance of $350 million in new 8.375% Senior Notes due 2028 related to the Southwestern debt offering and borrowings under Southwestern's credit facility used to pay off the Montage notes, Montage credit facility and related accrued interest. Management believes the estimates and assumptions are reasonable, and the relative effects of the Merger are properly reflected.

Montage Merger-Related Expenses

The following table summarizes the Merger-related expenses incurred for the year ended December 31, 2020:

(in millions)	For the year ended December 31, 2020
Bank, legal and consulting fees	$ 18
Employee severance and related costs	17
Contract buyouts	5
Other	1
Total Montage merger-related expenses	$ 41

Employee severance and related employee cost primarily relates to one-time severance costs and the accelerated vesting of certain Montage share-based awards for former Montage employees based on the terms of the Agreement and Plan of Merger and existing change of control provisions within the former Montage employment agreements. Contract buyouts primarily consist of the costs associated with the settlement of contracts inherited from Montage that had no future value to the Company's ongoing business.

2019 Divestitures

During 2019, the Company sold non-core acreage for $38 million. There was no production or proved reserves associated with this acreage. In addition, during July 2019, the Company sold the land associated with its headquarters office building for $16 million and recognized a $2 million gain on the sale. The Company also from time to time sells leases and other properties whose value, individually, is not material but is reflected in the Company's financial statements.

Fayetteville Shale Sale

In December 2018, the Company closed the Fayetteville Shale sale and received approximately $1,650 million, which included purchase price adjustments of approximately $215 million primarily related to the net cash flows from the economic effective date to the closing date. The Company allocated the sale proceeds to gain on sale for the non-full cost pool assets and to capitalized costs for the full cost pool assets based on the proportion of the estimated fair values of the underlying assets. The fair values of these assets was estimated primarily using an income approach. Consequently, the Company recognized a gain on the sale of non-full cost pool assets of $17 million and a reduction of $887 million to its full cost pool assets. As the sale did not involve a significant change in proved reserves or significantly alter the relationship between capitalized costs and proved reserves, the Company recognized no gain or loss related to the full cost pool assets sold.

In accordance with accounting guidance for Property, Plant and Equipment, assets held for sale are measured at the lower of the carrying value or fair value less costs to sell. Because the assets outside the full cost pool included in the Fayetteville Shale sale met the criteria for held for sale accounting as of September 30, 2018, the Company determined the carrying value of certain non-full cost pool assets exceeded the fair value less costs to sell. As a result, a non-cash impairment charge of $161 million was recorded in the third quarter of 2018, of which $145 million related to midstream gathering assets held for sale and $15 million related to E&P assets held for sale. Additionally, the Company recorded a $1 million non-cash impairment related to other non-core assets that were not included in the sale.

(4) LEASES

As part of the Montage Merger, the Company acquired $25 million of operating right of use assets and corresponding lease liabilities which were recognized as part of the Company's acquisition accounting in the fourth quarter of 2020.

In July 2019, the Company terminated its existing lease agreement and entered into a new ten-year lease agreement for a smaller portion of the headquarters office building, which resulted in the Company making a $6 million residual value guarantee short-fall payment to the building's previous lessor. The Company's variable lease costs are primarily comprised of variable operating charges incurred in connection with the new building lease which are expected to continue throughout the lease term. There are currently no material residual value guarantees in the Company's existing leases.

The components of lease costs are shown below:

	For the years ended December 31,	
(in millions)	2020	2019
Operating lease cost	$ 48	$ 45
Short-term lease cost	35	45
Variable lease cost	3	1
Total lease cost	$ 86	$ 91

As of December 31, 2020, the Company had operating leases of $6 million, related primarily to compressor leases, that have been executed but not yet commenced. These operating leases are planned to commence during 2021 with lease terms expiring through 2024. The Company's existing operating leases do not contain any material restrictive covenants.

Supplemental cash flow information related to leases is set forth below:

	For the years ended December 31,	
(in millions)	2020	2019
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$ 47	$ 47
Right-of-use assets obtained in exchange for operating liabilities:		
Operating leases	$ 48	$ 95

Supplemental balance sheet information related to leases is as follows:

(in millions)	December 31, 2020	December 31, 2019
Right-of-use asset balance:		
Operating leases	$ 163	$ 159
Lease liability balance:		
Current operating leases	$ 42	$ 34
Long-term operating leases	117	119
Total operating leases	$ 159	$ 153
Weighted average remaining lease term: *(years)*		
Operating leases	5.6	6.6
Weighted average discount rate:		
Operating leases	5.97 %	5.33 %

Maturity analysis of operating lease liabilities:

(in millions)	December 31, 2020
2021	$ 50
2022	37
2023	26
2024	18
2025	14
Thereafter	42
Total undiscounted lease liability	187
Imputed interest	(28)
Total discounted lease liability	$ 159

(5) REVENUE RECOGNITION

Effective January 1, 2018, the Company adopted ASC 606, "Revenue from Contracts with Customers," using the modified retrospective method applied to those contracts which were not completed as of January 1, 2018. Under the modified retrospective method, the Company recognizes the cumulative effect of initially applying the new revenue standard as an adjustment to the opening balance of retained earnings; however, no material adjustment was required as a result of adopting ASC 606. Results for reporting periods beginning on January 1, 2018 are presented under the new revenue standard. The comparative information has not been restated and continues to be reported under the accounting standards in effect for those periods. The Company performed an analysis of the impact of adopting ASC 606 across all revenue streams and did not identify any changes to its revenue recognition policies that resulted in a material impact to its consolidated financial statements.

Revenues from Contracts with Customers

Natural gas and liquids. Natural gas, oil and NGL sales are recognized when control of the product is transferred to the customer at a designated delivery point. The pricing provisions of the Company's contracts are primarily tied to a market index with certain adjustments based on factors such as delivery, quality of the product and prevailing supply and demand conditions in the geographic areas in which the Company operates. Under the Company's sales contracts, the delivery of each unit of natural gas, oil and NGLs represents a separate performance obligation, and revenue is recognized at the point in time when the performance obligations are fulfilled. There is no significant financing component to the Company's revenues as payment terms are typically within 30 to 60 days of control transfer. Furthermore, consideration from a customer corresponds directly with the value to the customer of the Company's performance completed to date. As a result, the Company recognizes revenue in the amount to which the Company has a right to invoice and has not disclosed information regarding its remaining performance obligations.

The Company records revenue from its natural gas and liquids production in the amount of its net revenue interest in sales from its properties. Accordingly, natural gas and liquid sales are not recognized for deliveries in excess of the Company's net revenue interest, while natural gas and liquid sales are recognized for any under-delivered volumes.

Marketing. The Company, through its marketing affiliate, generally markets natural gas, oil and NGLs for its affiliated E&P companies as well as other joint owners who choose to market with the Company. In addition, the Company markets some products purchased from third parties. Marketing revenues for natural gas, oil and NGL sales are recognized when control of the product is transferred to the customer at a designated delivery point. The pricing provisions of the Company's contracts are primarily tied to market indices with certain adjustments based on factors such as delivery, quality of the product and prevailing supply and demand conditions. Under the Company's marketing contracts, the delivery of each unit of natural gas, oil and NGLs represents a separate performance obligation, and revenue is recognized at the point in time when the performance obligations are fulfilled. Customers are invoiced and revenues are recorded each month as natural gas, oil and NGLs are delivered, and payment terms are typically within 30 to 60 days of control transfer. Furthermore, consideration from a customer corresponds directly with the value to the customer of the Company's performance completed to date. As a result, the Company recognizes revenue in the amount to which the Company has a right to invoice and has not disclosed information regarding its remaining performance obligations.

Gas gathering. Prior to the Fayetteville Shale sale in December 2018, the Company, through its midstream gathering affiliate, gathered natural gas pursuant to a variety of contracts with customers, including an affiliated E&P company. The performance obligations for gas gathering services included delivery of each unit of natural gas to the designated delivery point, which may include treating of certain natural gas units to meet interstate pipeline specifications. Revenue was recognized at the point in time when performance obligations were fulfilled. Under the Company's gathering contracts, customers were invoiced and revenue was recognized each month based on the volume of natural gas transported and treated at a contractually agreed upon price per unit. Payment terms were typically within 30 to 60 days of completion of the performance obligations. Furthermore, consideration from a customer corresponded directly with the value to the customer of the Company's performance completed to date. As a result, the Company recognized revenue in the amount to which the Company had a right to invoice and had not disclosed information regarding its remaining performance obligations. Any imbalances were settled on a monthly basis by cashing-out with the respective shipper. Accordingly, there were no contract assets or contract liabilities related to the Company's gas gathering revenues.

Disaggregation of Revenues

The Company presents a disaggregation of E&P revenues by product in the consolidated statements of operations net of intersegment revenues. The following table reconciles operating revenues as presented on the consolidated statements of operations to the operating revenues by segment:

(in millions)	E&P	Marketing	Intersegment Revenues	**Total**
Year ended December 31, 2020				
Gas sales	$ 928	$ —	$ 39	**$ 967**
Oil sales	150	—	4	**154**
NGL sales	265	—	—	**265**
Marketing	—	2,145	(1,228)	**917**
Other [(1)]	5	—	—	**5**
Total	**$ 1,348**	**$ 2,145**	**$ (1,185)**	**$ 2,308**
Year ended December 31, 2019				
Gas sales	$ 1,207	$ —	$ 34	**$ 1,241**
Oil sales	220	—	3	**223**
NGL sales	274	—	—	**274**
Marketing	—	2,849	(1,552)	**1,297**
Other [(1)]	2	1	—	**3**
Total	**$ 1,703**	**$ 2,850**	**$ (1,515)**	**$ 3,038**
Year ended December 31, 2018				
Gas sales	$ 1,974	$ —	$ 24	**$ 1,998**
Oil sales	193	—	3	**196**
NGL sales	353	—	(1)	**352**
Marketing	—	3,497	(2,275)	**1,222**
Gas gathering [(2)]	—	248	(159)	**89**
Other [(1)]	5	—	—	**5**
Total	**$ 2,525**	**$ 3,745**	**$ (2,408)**	**$ 3,862**

(1) Other E&P revenues consists primarily of water sales to third-party operators and other marketing revenues consists primarily of sales of gas from storage.

(2) The Company's gas gathering assets were divested in December 2018 as part of the Fayetteville Shale sale.

Associated E&P revenues are also disaggregated for analysis on a geographic basis by the core areas in which the Company operates, which are primarily in Pennsylvania and West Virginia. In December 2018, the Company sold 100% of its Fayetteville Shale assets.

	For the years ended December 31,		
(in millions)	2020	2019	2018
Northeast Appalachia	$ 648	$ 964	$ 1,165
Southwest Appalachia	700	736	817
Fayetteville Shale	—	—	537
Other	—	3	6
Total	$ 1,348	$ 1,703	$ 2,525

Receivables from Contracts with Customers

The following table reconciles the Company's receivables from contracts with customers to consolidated accounts receivable as presented on the consolidated balance sheet:

(in millions)	December 31, 2020	December 31, 2019
Receivables from contracts with customers	$ 350	$ 284
Other accounts receivable	18	61
Total accounts receivable	$ 368	$ 345

Amounts recognized against the Company's allowance for doubtful accounts related to receivables arising from contracts with customers were immaterial for the years ended December 31, 2020 and 2019. The Company has no contract assets or contract liabilities associated with its revenues from contracts with customers.

(6) DERIVATIVES AND RISK MANAGEMENT

The Company is exposed to volatility in market prices and basis differentials for natural gas, oil and NGLs, which impacts the predictability of its cash flows related to the sale of those commodities. These risks are managed by the Company's use of certain derivative financial instruments. As of December 31, 2020, the Company's derivative financial instruments consisted of fixed price swaps, two-way costless collars, three-way costless collars, basis swaps, call options and interest rate swaps. A description of the Company's derivative financial instruments is provided below:

Fixed price swaps	If the Company sells a fixed price swap, the Company receives a fixed price for the contract and pays a floating market to the counterparty. If the Company purchases a fixed price swap, the Company receives a floating market price for the contract and pays a fixed price to the counterparty.
Two-way costless collars	Arrangements that contain a fixed floor price (purchased put option) and a fixed ceiling price (sold call option) based on an index price which, in aggregate, have no net cost. At the contract settlement date, (1) if the index price is higher than the ceiling price, the Company pays the counterparty the difference between the index price and ceiling price, (2) if the index price is between the floor and ceiling prices, no payments are due from either party, and (3) if the index price is below the floor price, the Company will receive the difference between the floor price and the index price.
Three-way costless collars	Arrangements that contain a purchased put option, a sold call option and a sold put option based on an index price which, in aggregate, have no net cost. At the contract settlement date, (1) if the index price is higher than the sold call strike price, the Company pays the counterparty the difference between the index price and sold call strike price, (2) if the index price is between the purchased put strike price and the sold call strike price, no payments are due from either party, (3) if the index price is between the sold put strike price and the purchased put strike price, the Company will receive the difference between the purchased put strike price and the index price, and (4) if the index price is below the sold put strike price, the Company will receive the difference between the purchased put strike price and the sold put strike price.

Basis swaps	Arrangements that guarantee a price differential for natural gas from a specified delivery point. If the Company sells a basis swap, the Company receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract. If the Company purchases a basis swap, the Company pays the counterparty if the price differential is greater than the state terms of the contract and receives a payment from the counterparty if the price differential is less than the stated terms of the contract.
Call options	The Company purchases and sells call options in exchange for a premium. If the Company purchases a call option, the Company receives from the counterparty the excess (if any) of the market price over the strike price of the call option at the time of settlement, but if the market price is below the call's strike price, no payment is due from either party. If the Company sells a call option, the Company pays the counterparty the excess (if any) of the market price over the strike price at the time of settlement, but if the market price is below the call's strike price, no payment is due from either party.
Swaptions	Instruments that refer to an option to enter into a fixed price swap. In exchange for an option premium, the purchaser gains the right but not the obligation to enter a specified swap agreement with the issuer for specified future dates. If the Company sells a swaption, the counterparty has the right to enter into a fixed price swap wherein the Company receives a fixed price for the contract and pays a floating market price to the counterparty. If the Company purchases a swaption, the Company has the right to enter into a fixed price swap wherein the Company receives a floating market price for the contract and pays a fixed price to the counterparty.
Interest rate swaps	Interest rate swaps are used to fix or float interest rates on existing or anticipated indebtedness. The purpose of these instruments is to manage the Company's existing or anticipated exposure to unfavorable interest rate changes.

The Company chooses counterparties for its derivative instruments that it believes are creditworthy at the time the transactions are entered into, and the Company actively monitors the credit ratings and credit default swap rates of these counterparties where applicable. However, there can be no assurance that a counterparty will be able to meet its obligations to the Company. The Company presents its derivative positions on a gross basis and does not net the asset and liability positions.

The following tables provide information about the Company's financial instruments that are sensitive to changes in commodity prices and that are used to protect the Company's exposure. None of the financial instruments below are designated for hedge accounting treatment. The tables present the notional amount, the weighted average contract prices and the fair value by expected maturity dates as of December 31, 2020:

Financial Protection on Production

		Weighted Average Price per MMBtu					Fair value at December 31, 2020
	Volume *(Bcf)*	Swaps	Sold Puts	Purchased Puts	Sold Calls	Basis Differential	*($ in millions)*
Natural Gas							
2021							
Fixed price swaps	201	$ 2.80	$ —	$ —	$ —	$ —	$ 29
Two-way costless collars	237	—	—	2.57	2.95	—	11
Three-way costless collars	313	—	2.16	2.49	2.85	—	(24)
Total	751						$ 16
2022							
Fixed price swaps	112	$ 2.68	$ —	$ —	$ —	$ —	$ 4
Two-way costless collars	63	—	—	2.52	3.03	—	(1)
Three-way costless collars	203	—	2.06	2.46	2.89	—	(15)
Total	378						$ (12)
2023							
Three-way costless collars	87	$ —	$ 2.06	$ 2.47	$ 2.98	$ —	$ —
Basis swaps							
2021	219	$ —	$ —	$ —	$ —	$ (0.21)	$ 57
2022	139	—	—	—	—	(0.33)	8
2023	47	—	—	—	—	(0.45)	—
2024	11	—	—	—	—	(0.60)	—
2025	4	—	—	—	—	(0.59)	—
Total	420						$ 65

		Weighted Average Price per Bbl				
	Volume *(MBbls)*	Swaps	Sold Puts	Purchased Puts	Sold Calls	Fair value at December 31, 2020 *($ in millions)*
Oil						
2021						
Fixed price swaps	4,887	$ 48.59	$ —	$ —	$ —	$ 1
Two-way costless collars	201	—	—	37.73	45.68	(1)
Three-way costless collars	1,543	—	37.42	47.22	52.86	—
Total	6,631					$ —
2022						
Fixed price swaps	1,282	$ 46.37	$ —	$ —	$ —	$ —
Three-way costless collars	873	—	40.25	50.78	56.54	1
Total	2,155					$ 1
2023						
Three-way costless collars	878	$ —	$ 33.52	$ 43.52	$ 53.41	$ (1)
Ethane						
2021						
Fixed price swaps	5,889	$ 7.12	$ —	$ —	$ —	$ (10)
Two-way costless collars	584	—	—	7.14	10.40	—
Total	6,473					$ (10)
2022						
Fixed price swaps	1,575	$ 8.69	$ —	$ —	$ —	$ —
Two-way costless collars	135	—	—	7.56	9.66	—
Total	1,710					$ —
Propane						
2021						
Fixed price swaps	6,974	$ 20.43	$ —	$ —	$ —	$ (36)
2022						
Fixed price swaps	2,120	$ 20.23	$ —	$ —	—	$ (2)
Normal Butane						
2021						
Fixed price swaps	2,004	$ 24.97	$ —	$ —	$ —	$ (8)
2022						
Fixed price swaps	667	$ 22.77	$ —	$ —	$ —	$ (1)
Natural Gasoline						
2021						
Fixed price swaps	1,936	$ 37.35	$ —	$ —	$ —	$ (13)
2022						
Fixed price swaps	643	$ 37.77	$ —	$ —	$ —	$ (2)

Other Derivative Contracts

	Volume *(Bcf)*	Weighted Average Strike Price per MMBtu	Fair value at December 31, 2020 *($ in millions)*
Call Options – Natural Gas (Net)			
2021	75	$ 3.19	$ (8)
2022	77	3.00	(17)
2023	46	2.94	(8)
2024	9	3.00	(3)
Total	207		$ (36)
Put Options – Natural Gas			
2021	18	$ 2.00	$ (1)
2022	5	2.00	—
Total	23		$ (1)

	Volume *(MBbls)*	Weighted Average Strike Price per Bbl	Fair value at December 31, 2020 *($ in millions)*
Sold Call Options – Oil			
2021	226	$ 60.00	$ —

	Volume *(Bcf)*	Weighted Average Strike Price per MMBtu	Fair value at December 31, 2020 *($ in millions)*
Swaptions – Natural Gas			
2021	0.1	$ 3.00	$ (2)

		Weighted Average Strike Price per MMBtu		Fair value at December 31, 2020 *($ in millions)*
Storage (1)	Volume *(Bcf)*	Swaps	Basis Differential	
2021				
Purchased fixed price swap	1	$ 2.04	$ —	$ —
Fixed price swaps	2	2.49	—	—
Basis swaps	1	—	(0.38)	—
Total	4			$ —

(1) The Company has entered into certain derivatives to protect the value of volumes of natural gas injected into a storage facility that will be withdrawn at a later date.

	Volume *(Bcf)*	Weighted Average Strike Price per MMBtu	Fair value at December 31, 2020 *($ in millions)*
Purchased Fixed Price Swaps – Marketing (Natural Gas) (1)			
2021	6	$ 2.44	$ 1

(1) The Company has entered into a limited number of derivatives to protect the value of certain long-term sales contracts.

At December 31, 2020, the net fair value of the Company's financial instruments related to commodities was a $41 million liability and included a net reduction of the liability of $1 million due to non-performance risk. See Note 8 for additional details regarding the Company's fair value measurements of its derivative positions.

As of December 31, 2020, the Company had no positions designated for hedge accounting treatment. Gains and losses on derivatives that are not designated for hedge accounting treatment, or do not meet hedge accounting requirements, are recorded as a component of gain (loss) on derivatives on the consolidated statements of operations. Accordingly, the gain (loss) on derivatives component of the statement of operations reflects the gains and losses on both settled and unsettled derivatives. Only the settled gains and losses are included in the Company's realized commodity price calculations.

The balance sheet classification of the assets and liabilities related to derivative financial instruments are summarized below as of December 31, 2020 and 2019:

Derivative Assets

(in millions)	Balance Sheet Classification	Fair Value December 31, 2020	Fair Value December 31, 2019
Derivatives not designated as hedging instruments:			
Purchased fixed price swaps – natural gas	Derivative assets	$ 1	$ —
Fixed price swaps – natural gas	Derivative assets	37	77 (1)
Fixed price swaps – oil	Derivative assets	13	4
Fixed price swaps – ethane	Derivative assets	—	11
Fixed price swaps – propane	Derivative assets	—	21
Two-way costless collars – natural gas	Derivative assets	54	10
Two-way costless collars – oil	Derivative assets	—	5
Two-way costless collars – propane	Derivative assets	—	2
Three-way costless collars – natural gas	Derivative assets	57	126
Three-way costless collars – oil	Derivative assets	15	3
Basis swaps – natural gas	Derivative assets	60	17
Call options – natural gas	Derivative assets	4	1
Fixed price swaps – natural gas storage	Derivative assets	—	1
Fixed price swaps – natural gas	Other long-term assets	7	7
Fixed price swaps – oil	Other long-term assets	2	1
Fixed price swaps – propane	Other long-term assets	—	3
Two-way costless collars – natural gas	Other long-term assets	20	4
Three-way costless collars – natural gas	Other long-term assets	87	74
Three-way costless collars – oil	Other long-term assets	15	7
Basis swaps – natural gas	Other long-term assets	15	15
Call options – natural gas	Other long-term assets	—	2
Total derivative assets		$ 387	$ 391

(1) Includes $9 million in premiums paid related to certain natural gas fixed price swaps recognized as a component of derivative assets within current assets on the consolidated balance sheet at December 31, 2019. As certain natural gas fixed price swaps settle, the premium will be amortized and recognized as a component of gain (loss) on derivatives on the consolidated statements of operations.

Derivative Liabilities

(in millions)	Balance Sheet Classification	Fair Value December 31, 2020	Fair Value December 31, 2019
Derivatives not designated as hedging instruments:			
Purchased fixed price swaps – natural gas	Derivative liabilities	$ —	$ 1
Fixed price swaps – natural gas	Derivative liabilities	7	1
Fixed price swaps – oil	Derivative liabilities	12	6
Fixed price swaps – ethane	Derivative liabilities	10	—
Fixed price swaps – propane	Derivative liabilities	36	—
Fixed price swaps – normal butane	Derivative liabilities	8	—
Fixed price swaps – natural gasoline	Derivative liabilities	13	—
Two-way costless collars – natural gas	Derivative liabilities	43	4
Two-way costless collars – oil	Derivative liabilities	1	5
Three-way costless collars – natural gas	Derivative liabilities	82	84
Three-way costless collars – oil	Derivative liabilities	15	4
Basis swaps – natural gas	Derivative liabilities	3	17
Call options – natural gas	Derivative liabilities	12	3
Put options – natural gas	Derivative liabilities	1	—
Swaptions – natural gas	Derivative liabilities	2	—
Fixed price swaps – natural gas	Other long-term liabilities	3	—
Fixed price swaps – oil	Other long-term liabilities	2	2
Fixed price swaps – propane	Other long-term liabilities	2	—
Fixed price swaps – normal butane	Other long-term liabilities	1	—
Fixed price swaps – natural gasoline	Other long-term liabilities	2	—
Two-way costless collars – natural gas	Other long-term liabilities	21	4
Three-way costless collars – natural gas	Other long-term liabilities	102	72
Three-way costless collars – oil	Other long-term liabilities	15	8
Basis swaps – natural gas	Other long-term liabilities	7	9
Call options – natural gas	Other long-term liabilities	28	15
Call options – oil	Other long-term liabilities	—	1
Total derivative liabilities		$ 428	$ 236

The following tables summarize the before-tax effect of the Company's derivative instruments on the consolidated statements of operations for the years ended December 31, 2020 and 2019:

Unsettled Gain (Loss) on Derivatives Recognized in Earnings

Derivative Instrument	Consolidated Statement of Operations Classification of Gain (Loss) on Derivatives, Unsettled	For the years ended December 31, 2020	2019
		(in millions)	
Purchased fixed price swaps – natural gas	Gain (Loss) on Derivatives	$ 2	$ (1)
Purchased fixed price swaps – oil	Gain (Loss) on Derivatives	—	6
Fixed price swaps – natural gas	Gain (Loss) on Derivatives	(25)	46
Fixed price swaps – oil	Gain (Loss) on Derivatives	—	(22)
Fixed price swaps – ethane	Gain (Loss) on Derivatives	(21)	6
Fixed price swaps – propane	Gain (Loss) on Derivatives	(60)	13
Fixed price swaps – normal butane	Gain (Loss) on Derivatives	(9)	—
Fixed price swaps – natural gasoline	Gain (Loss) on Derivatives	(15)	—
Two-way costless collars – natural gas	Gain (Loss) on Derivatives	10	2
Two-way costless collars – oil	Gain (Loss) on Derivatives	(1)	(10)
Two-way costless collars – propane	Gain (Loss) on Derivatives	(1)	2
Three-way costless collars – natural gas	Gain (Loss) on Derivatives	(77)	37
Three-way costless collars – oil	Gain (Loss) on Derivatives	3	(2)
Basis swaps – natural gas	Gain (Loss) on Derivatives	59	17
Call options – natural gas	Gain (Loss) on Derivatives	(10)	1
Call options – oil	Gain (Loss) on Derivatives	1	(1)
Swaptions – natural gas	Gain (Loss) on Derivatives	7	—
Fixed price swaps – natural gas storage	Gain (Loss) on Derivatives	(1)	1
Interest rate swaps	Gain (Loss) on Derivatives	—	(1)
Total gain (loss) on unsettled derivatives		$ (138)	$ 94

Settled Gain (Loss) on Derivatives Recognized in Earnings [(1)]

Derivative Instrument	Consolidated Statement of Operations Classification of Gain (Loss) on Derivatives, Settled	For the years ended December 31, 2020	2019
		(in millions)	
Purchased fixed price swaps – natural gas	Gain (Loss) on Derivatives	$ (3)	$ —
Purchased fixed price swaps – oil	Gain (Loss) on Derivatives	—	(3)
Fixed price swaps – natural gas	Gain (Loss) on Derivatives	142 (2)	78
Fixed price swaps – oil	Gain (Loss) on Derivatives	65	10
Fixed price swaps – ethane	Gain (Loss) on Derivatives	6	17
Fixed price swaps – propane	Gain (Loss) on Derivatives	18	29
Fixed price swaps – normal butane	Gain (Loss) on Derivatives	(2)	—
Fixed price swaps – natural gasoline	Gain (Loss) on Derivatives	(1)	—
Two-way costless collars – natural gas	Gain (Loss) on Derivatives	(5)	16
Two-way costless collars – oil	Gain (Loss) on Derivatives	17	6
Two-way costless collars – propane	Gain (Loss) on Derivatives	2	2
Three-way costless collars – natural gas	Gain (Loss) on Derivatives	38 (3)	31
Three-way costless collars – oil	Gain (Loss) on Derivatives	9	—
Basis swaps – natural gas	Gain (Loss) on Derivatives	76	(3)
Call options – natural gas	Gain (Loss) on Derivatives	—	(2) (4)
Purchased fixed price swaps – natural gas storage	Gain (Loss) on Derivatives	(1)	—
Fixed price swaps – natural gas storage	Gain (Loss) on Derivatives	2	(1)
Interest rate swaps	Gain (Loss) on Derivatives	(1)	—
Total gain on settled derivatives		$ 362	$ 180
Total gain on derivatives		$ 224	$ 274

(1) The Company calculates gain (loss) on derivatives, settled, as the summation of gains and losses on positions that have settled within the period.

(2) Includes $9 million amortization of premiums paid related to certain natural gas fixed price options for the year ended December 31, 2020, which is included in gain (loss) on derivatives on the consolidated statements of operations.

(3) Includes $2 million amortization of premiums paid related to certain natural gas three-way costless collars for the year ended December 31, 2020, which is included in gain (loss) on derivatives on the consolidated statements of operations.

(4) Includes $1 million amortization of premiums paid related to certain natural gas call options for the year ended December 31, 2019, which is included in gain (loss) on derivatives on the consolidated statement of operations.

(7) RECLASSIFICATIONS FROM ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

In 2020, changes in AOCI primarily related to settlements in the Company's pension and other postretirement benefits. The following tables detail the components of accumulated other comprehensive income (loss) and the related tax effects, for the year ended December 31, 2020:

	For the year ended December 31, 2020		
(in millions)	Pension and Other Postretirement	Foreign Currency	**Total**
Beginning balance, December 31, 2019	$ (19)	$ (14)	**$ (33)**
Other comprehensive loss before reclassifications	—	—	—
Amounts reclassified from other comprehensive income [1]	(5)	—	**(5)**
Net current-period other comprehensive loss	(5)	—	**(5)**
Ending balance, December 31, 2020	**$ (24)**	**$ (14)**	**$ (38)**

(1) See separate table below for details about these reclassifications.

Details about Accumulated Other Comprehensive Income	Affected Line Item in the Consolidated Statement of Operations	Amount Reclassified from/to Accumulated Other Comprehensive Income
		For the year ended December 31, 2020
Pension and other postretirement:		*(in millions)*
Amortization of prior service cost and net loss [1]	Other Loss, Net	$ (6)
	Provision for income taxes	(1)
	Net loss	$ (5)
Total reclassifications for the period	Net loss	$ (5)

(1) See Note 13 for additional details regarding the Company's pension and other postretirement benefit plans.

(8) FAIR VALUE MEASUREMENTS

Assets and liabilities measured at fair value on a recurring basis

The carrying amounts and estimated fair values of the Company's financial instruments as of December 31, 2020 and 2019 were as follows:

	December 31, 2020		December 31, 2019	
(in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	$ 13	$ 13	$ 5	$ 5
2018 revolving credit facility due April 2024 [1]	700	700	34	34
Senior notes [2]	2,471	2,609	2,228	2,085
Derivative instruments, net	(41)	(41)	155 [3]	155 [3]

(1) In October 2019, the Company amended its 2018 revolving credit facility agreement which, among other things, extended the maturity from 2023 to 2024.

(2) Excludes unamortized debt issuance costs and debt discounts.

(3) Includes $9 million in premiums paid as of December 31, 2019 related to certain natural gas fixed price swaps recognized as a component of derivative assets within current assets on the consolidated balance sheet.

The fair value hierarchy prioritizes the inputs to valuation techniques used to measure fair value. As presented in the tables below, this hierarchy consists of three broad levels:

Level 1 valuations – Consist of unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority.

Level 2 valuations – Consist of quoted market information for the calculation of fair market value.

Level 3 valuations – Consist of internal estimates and have the lowest priority.

The carrying values of cash and cash equivalents, including marketable securities, accounts receivable, other current assets, accounts payable and other current liabilities on the consolidated balance sheets approximate fair value because of their short-term nature. For debt and derivative instruments, the following methods and assumptions were used to estimate fair value:

Debt: The fair values of the Company's senior notes were based on the market value of the Company's publicly traded debt as determined based on the market prices of the Company's senior notes. The fair value of the Company's 4.10% Senior Notes due March 2022 is considered to be a Level 2 measurement on the fair value hierarchy. The fair values of the Company's remaining senior notes are considered to be a Level 1 measurement. The carrying values of the borrowings under the Company's revolving credit facility (to the extent utilized) approximates fair value because the interest rate is variable and reflective of market rates. The Company considers the fair value of its revolving credit facility to be a Level 1 measurement on the fair value hierarchy.

Derivative Instruments: The Company measures the fair value of its derivative instruments based upon a pricing model that utilizes market-based inputs, including, but not limited to, the contractual price of the underlying position, current market prices, natural gas and liquids forward curves, discount rates such as the LIBOR curve for a similar duration of each outstanding position, volatility factors and non-performance risk. Non-performance risk considers the effect of the Company's credit standing on the fair value of derivative liabilities and the effect of counterparty credit standing on the fair value of derivative assets. Both inputs to the model are based on published credit default swap rates and the duration of each outstanding derivative position. As of December 31, 2020, the impact of non-performance risk on the fair value of the Company's net derivative liability position was a reduction of the liability of $1 million.

The Company has classified its derivative instruments into levels depending upon the data utilized to determine their fair values. The Company's fixed price swaps (Level 2) are estimated using third-party discounted cash flow calculations using the New York Mercantile Exchange ("NYMEX") futures index for natural gas and oil derivatives and Oil Price Information Service ("OPIS") for ethane and propane derivatives. The Company utilizes discounted cash flow models for valuing its interest rate derivatives (Level 2). The net derivative values attributable to the Company's interest rate derivative contracts as of December 31, 2020 are based on (i) the contracted notional amounts, (ii) active market-quoted London Interbank Offered Rate ("LIBOR") yield curves and (iii) the applicable credit-adjusted risk-free rate yield curve.

The Company's call options, two-way costless collars, three-way costless collars and swaptions (Level 2) are valued using the Black-Scholes model, an industry standard option valuation model that takes into account inputs such as contract terms, including maturity, and market parameters, including assumptions of the NYMEX and OPIS futures index, interest rates, volatility and credit worthiness. Inputs to the Black-Scholes model, including the volatility input are obtained from a third-party pricing source, with independent verification of the most significant inputs on a monthly basis. An increase (decrease) in volatility would result in an increase (decrease) in fair value measurement, respectively.

The Company's basis swaps (Level 2) are estimated using third-party calculations based upon forward commodity price curves.

Assets and liabilities measured at fair value on a recurring basis are summarized below:

	December 31, 2020			
	Fair Value Measurements Using:			
(in millions)	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Assets (Liabilities) at Fair Value
Assets:				
Purchased fixed price swaps	$ —	$ 1	$ —	$ 1
Fixed price swaps	—	59	—	59
Two-way costless collars	—	74	—	74
Three-way costless collars	—	174	—	174
Basis swaps	—	75	—	75
Call options	—	4	—	4
Liabilities:				
Fixed price swaps	—	(96)	—	(96)
Two-way costless collars	—	(65)	—	(65)
Three-way costless collars	—	(214)	—	(214)
Basis swaps	—	(10)	—	(10)
Call options	—	(40)	—	(40)
Put options	—	(1)	—	(1)
Swaptions	—	(2)	—	(2)
Total	$ —	$ (41)	$ —	$ (41)

	December 31, 2019			
	Fair Value Measurements Using:			
(in millions)	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Assets (Liabilities) at Fair Value
Assets:				
Fixed price swaps [(1)]	$ —	$ 125	$ —	$ 125
Two-way costless collars	—	21	—	21
Three-way costless collars	—	210	—	210
Basis swaps – natural gas	—	32	—	32
Call options	—	3	—	3
Liabilities:				
Purchased fixed price swaps	—	(1)	—	(1)
Fixed price swaps	—	(9)	—	(9)
Two-way costless collars	—	(13)	—	(13)
Three-way costless collars	—	(168)	—	(168)
Basis swaps	—	(26)	—	(26)
Call options	—	(19)	—	(19)
Total	$ —	$ 155	$ —	$ 155

(1) Includes $9 million in premiums paid related to certain natural gas fixed price swaps recognized as a component of derivative assets within current assets on the consolidated balance sheet at December 31, 2019. As certain natural gas fixed price swaps settle, the premium will be amortized and recognized as a component of gain (loss) on derivatives on the consolidated statement of operations.

See Note 13 for a discussion of the fair value measurement of the Company's pension plan assets.

Assets and liabilities measured at fair value on a nonrecurring basis

On November 13, 2020, the Company completed the Merger with Montage. See Note 3 for a discussion of the fair value measurement of assets acquired and liabilities assumed.

In 2020, the Company determined that the $6 million carrying value of certain non-core assets exceeded their respective fair value less costs to sell and recognized a $5 million non-cash impairment. The Company used Level 2 measurements to determine the fair value of these assets.

In 2019, the Company determined that the $26 million carrying value of certain non-core assets exceeded their respective fair value less costs to sell and recognized a $16 million non-cash impairment. The Company used Level 3 measurements to determine the fair value of these assets.

In the third quarter of 2018, the Company determined the carrying value of certain non-full cost pool assets associated with the Fayetteville Shale sale exceeded the fair value less costs to sell. In accordance with accounting guidance for Property, Plant and Equipment, assets held for sale are measured at the lower of carrying value or fair value less costs to sell. Because the assets outside of the full cost pool included in the Fayetteville Shale sale met the criteria for held for sale accounting, the Company recorded a non-cash impairment charge of $161 million for the year ended December 31, 2018, of which $145 million related to midstream gathering assets and $15 million related to E&P which were both reflected as assets held for sale in the third quarter of 2018. Additionally, the Company recorded a $1 million non-cash impairment related to other non-core assets that were not included in the sale. The estimated fair value of the gathering assets was based on an estimated discounted cash flow model and market assumptions. The significant Level 3 assumptions used in the calculation of estimated discounted cash flows included future commodity prices, projections of estimated quantities of natural gas reserves, operating costs, projections of future rates of production, inflation factors and risk adjusted discount rates.

(9) DEBT

The components of debt as of December 31, 2020 and 2019 consisted of the following:

	December 31, 2020			
(in millions)	Debt Instrument	Unamortized Issuance Expense	Unamortized Debt Discount	Total
Long-term debt:				
Variable rate (2.110% at December 31, 2020) 2018 revolving credit facility, due April 2024	$ 700	$ — [1]	$ —	$ 700
4.10% Senior Notes due March 2022	207	—	—	207
4.95% Senior Notes due January 2025 [2]	856	(4)	(1)	851
7.50% Senior Notes due April 2026	618	(6)	—	612
7.75% Senior Notes due October 2027	440	(5)	—	435
8.375% Senior Notes due September 2028	350	(5)	—	345
Total long-term debt	$ 3,171	$ (20)	$ (1)	$ 3,150

	December 31, 2019			
(in millions)	Debt Instrument	Unamortized Issuance Expense	Unamortized Debt Discount	Total
Long-term debt:				
Variable rate (4.310% at December 31, 2019) 2018 revolving credit facility, due April 2024	$ 34	$ — [1]	$ —	$ 34
4.10% Senior Notes due March 2022	213	(1)	—	212
4.95% Senior Notes due January 2025 [2]	892	(5)	(1)	886
7.50% Senior Notes due April 2026	639	(7)	—	632
7.75% Senior Notes due October 2027	484	(6)	—	478
Total long-term debt	$ 2,262	$ (19)	$ (1)	$ 2,242

(1) At December 31, 2020 and 2019, unamortized issuance expense of $12 million and $11 million, respectively, associated with the 2018 revolving credit facility (as defined below) was classified as other long-term assets on the consolidated balance sheet.

(2) Effective in July 2018, the interest rate was 6.20% for the 2025 Notes, reflecting a net downgrade in the Company's bond ratings since the initial offering. On April 7, 2020, S&P downgraded the Company's bond rating to BB-, which had the effect of increasing the interest rate on the 2025 Notes to 6.45% following the July 23, 2020 interest payment due date. The first coupon payment to the bondholders at the higher interest rate will be paid in January 2021.

The following is a summary of scheduled debt maturities by year as of December 31, 2020:

(in millions)	
2021	$ —
2022	207
2023	—
2024 [(1)]	700
2025	856
Thereafter	1,408
	$ 3,171

(1) The Company's current revolving credit facility matures in 2024.

Credit Facilities

2018 Credit Facility

In April 2018, the Company replaced its credit facility entered into in 2016 with a new revolving credit facility (the "2018 credit facility") with a group of banks that, as amended, has a maturity date of April 2024. The 2018 credit facility has an aggregate maximum revolving credit amount of $3.5 billion with a current aggregate commitment of $2.0 billion and borrowing base (limit on availability) that is redetermined at least each April and October. The 2018 credit facility is secured by substantially all of the assets owned by the Company and its subsidiaries. The permitted lien provisions in the senior notes indentures currently limit liens securing indebtedness to the greater of $2.0 billion and 25% of adjusted consolidated net tangible assets.

The Company may utilize the 2018 credit facility in the form of loans and letters of credit. Loans under the 2018 credit facility are subject to varying rates of interest based on whether the loan is a Eurodollar loan or an alternate base rate loan. Eurodollar loans bear interest at the Eurodollar rate, which is adjusted LIBOR for such interest period plus the applicable margin (as those terms are defined in the 2018 credit facility documentation). The applicable margin for Eurodollar loans under the 2018 credit facility, as amended, ranges from 1.75% to 2.75% based on the Company's utilization of the 2018 credit facility. Alternate base rate loans bear interest at the alternate base rate plus the applicable margin. The applicable margin for alternate base rate loans under the 2018 credit facility, as amended, ranges from 0.75% to 1.75% based on the Company's utilization of the 2018 credit facility.

In conjunction with the October 2020 redetermination process, the Company entered into an amendment to the credit agreement governing the 2018 credit facility to, among other matters:

- limit the Company's unrestricted cash and cash equivalents to $200 million when loans under the 2018 credit facility are outstanding, subject to certain exceptions; and
- increase the applicable rate by 25 basis points on loans outstanding under the 2018 credit facility.

In addition, the following amendments and redeterminations were made upon the closing of the Merger:

- increase the elected borrowing base and total aggregate commitments to $2.0 billion, the maximum permitted lien amount based on provisions in certain of the Company's senior note indentures;
- include certain Montage entities owning gas and oil properties as guarantors to the 2018 credit facility; and
- deem any Montage letters of credit issued prior to the Merger close to have been issued under the 2018 credit facility.

The 2018 credit facility contains customary representations and warranties and covenants including, among others, the following:

- a prohibition against incurring debt, subject to permitted exceptions;
- a restriction on creating liens on assets, subject to permitted exceptions;
- restrictions on mergers and asset dispositions;
- restrictions on use of proceeds, investments, transactions with affiliates, or change of principal business; and
- maintenance of the following financial covenants, commencing with the fiscal quarter ended June 30, 2018:
    (1) Minimum current ratio of no less than 1.00 to 1.00, whereby current ratio is defined as the Company's consolidated current assets (including unused commitments under the credit agreement, but excluding non-cash derivative assets) to consolidated current liabilities (excluding non-cash derivative obligations and current maturities of long-term debt).

(2) Maximum total net leverage ratio of no greater than, with respect to each fiscal quarter ending on or after June 30, 2020, 4.00 to 1.00. Total net leverage ratio is defined as total debt less cash on hand (up to the lesser of 10% of credit limit or $150 million) divided by consolidated EBITDAX for the last four consecutive quarters. For purposes of calculating consolidated EBITDAX, the Company can include the Montage consolidated EBITDAX prior to the merger for the same twelve-month rolling period. EBITDAX, as defined in the Company's 2018 credit agreement, excludes the effects of interest expense, depreciation, depletion and amortization, income tax, any non-cash impacts from impairments, certain non-cash hedging activities, stock-based compensation expense, non-cash gains or losses on asset sales, unamortized issuance cost, unamortized debt discount and certain restructuring costs.

The 2018 credit facility contains customary events of default that include, among other things, the failure to comply with the financial covenants described above, non-payment of principal, interest or fees, violation of covenants, inaccuracy of representations and warranties, bankruptcy and insolvency events, material judgments and cross-defaults to material indebtedness. If an event of default occurs and is continuing, all amounts outstanding under the 2018 credit facility may become immediately due and payable. As of December 31, 2020, the Company was in compliance with all of the covenants of the credit agreement in all material respects.

Each United States domestic subsidiary of the Company for which the Company owns 100% of its equity guarantees the 2018 credit facility. Pursuant to requirements under the indentures governing its senior notes, each subsidiary that became a guarantor of the 2018 credit facility also became a guarantor of each of the Company's senior notes.

As of December 31, 2020, the Company had $233 million in letters of credit and $700 million in borrowings outstanding under the 2018 credit facility.

The Company's exposure to the anticipated transition from LIBOR in late 2021 is limited to the 2018 credit facility. Upon announcement by the administrator of LIBOR identifying a specific date for LIBOR cessation, the credit agreement governing the 2018 credit facility will be amended to reference an alternative rate as established by JP Morgan, as Administrative Agent, and the Company. The alternative rate will be based on the prevailing market convention and is expected to be the Secured Overnight Financing Rate ("SOFR").

Senior Notes

In January 2015, the Company completed a public offering of $1.0 billion aggregate principal amount of its 4.95% Senior Notes due 2025 (the "2025 Notes"). The interest rate on the 2025 Notes is determined based upon the public bond ratings from Moody's and S&P. Downgrades on the 2025 Notes from either rating agency increase interest costs by 25 basis points per downgrade level and upgrades decrease interest costs by 25 basis points per upgrade level, up to the stated coupon rate, on the following semi-annual bond interest payment. Effective in July 2018, the interest rate for the 2015 Notes was 6.20%, reflecting a net downgrade in the Company's bond ratings since the initial offering. On April 7, 2020, S&P downgraded the Company's bond rating to BB-, which had the effect of increasing the interest rate on the 2025 Notes to 6.45% following the July 23, 2020 interest payment due date. The first coupon payment to the bondholders at the higher interest rate will be paid in January 2021. In the event of future downgrades, the coupons for this series of notes have been capped at 6.95%.

In the second half of 2019, the Company repurchased $35 million of its 4.95% senior notes due 2025, $11 million of its 7.50% Senior Notes due 2026 and $16 million of its 7.75% Senior Notes due 2027 at a discount for $54 million, and recognized an $8 million gain on extinguishment of debt. Additionally, in December 2019, the Company retired the remaining $52 million principal of its 4.05% Senior Notes due January 2020.

In the first half of 2020, the Company repurchased $6 million of its 4.10% senior notes due 2022, $36 million of its 4.95% senior notes due 2025, $21 million of its 7.50% senior notes due 2026 and $44 million of its 7.75% senior notes due 2027 for $72 million, and recognized a $35 million gain on the extinguishment of debt.

In August 2020, the Company completed a public offering of $350 million aggregate principal amount of its 2028 Notes, with net proceeds from the offering totaling approximately $345 million after underwriting discounts and offering expenses. The 2028 Notes were sold to the public at 100% of their face value. The net proceeds from the notes, in conjunction with the net proceeds from the August 2020 common stock offering and borrowings under the revolving credit facility, were utilized to fund a redemption of $510 million of Montage's Notes in connection with the closing of the Merger.

(10) COMMITMENTS AND CONTINGENCIES

Operating Commitments and Contingencies

As of December 31, 2020, the Company's contractual obligations for demand and similar charges under firm transportation and gathering agreements to guarantee access capacity on natural gas and liquids pipelines and gathering systems totaled approximately $8.5 billion, $531 million of which related to access capacity on future pipeline and gathering infrastructure projects that still require the granting of regulatory approvals and additional construction efforts. The Company also had guarantee obligations of up to $923 million of that amount. As of December 31, 2020, future payments under non-cancelable firm transportation and gathering agreements are as follows:

	Payments Due by Period					
(in millions)	**Total**	Less than 1 Year	1 to 3 Years	3 to 5 Years	5 to 8 Years	More than 8 Years
Infrastructure currently in service [(1)]	**$ 8,013**	$ 860	$ 1,532	$ 1,286	$ 1,813	$ 2,522
Pending regulatory approval and/or construction [(2)]	**531**	2	30	37	88	374
Total transportation charges	**$ 8,544**	$ 862	$ 1,562	$ 1,323	$ 1,901	$ 2,896

(1) With the close of the Montage Merger the Company acquired firm transportation commitments of approximately $1,100 million. These commitments approximate $99 million within the next year, $197 million from 1 to 3 years, $196 million from 3 to 5 years, $284 million from 5 to 8 years and $324 million beyond 8 years.

(2) Based on the estimated in-service dates as of December 31, 2020.

The Company leases pressure pumping equipment for its E&P operations under a single lease that expires in 2021. The current aggregate annual payment under this lease is approximately $6 million. The Company has seven leases for drilling rigs for its E&P operations that expire through 2025 with a current aggregate annual payment of approximately $11 million. The lease payments for the pressure pumping equipment, as well as other operating expenses for the Company's drilling operations, are capitalized to natural gas and oil properties and are partially offset by billings to third-party working interest owners.

The Company leases office space, vehicles and equipment under non-cancelable operating leases expiring through 2036. As of December 31, 2020, future minimum payments under these non-cancelable leases accounted for as operating leases (including short-term) are approximately $30 million in 2021, $21 million in 2022, $18 million in 2023, $14 million in 2024, $12 million in 2025 and $36 million thereafter.

The Company also has commitments for compression services and compression rentals related to its E&P segment. As of December 31, 2020, future minimum payments under these non-cancelable agreements (including short-term obligations) are approximately $20 million in 2021, $14 million in 2022, $3 million in 2022 and less than $1 million in 2024.

In the first quarter of 2019, the Company agreed to purchase firm transportation with pipelines in the Appalachian basin starting in 2021 and running through 2032 totaling $357 million in total contractual commitments, which is presented in the table above; the seller has agreed to reimburse $133 million of these commitments.

Environmental Risk

The Company is subject to laws and regulations relating to the protection of the environment. Environmental and cleanup related costs of a non-capital nature are accrued when it is both probable that a liability has been incurred and when the amount can be reasonably estimated. Management believes any future remediation or other compliance related costs will not have a material effect on the financial position, results of operations or cash flows of the Company.

Litigation

The Company is subject to various litigation, claims and proceedings, most of which have arisen in the ordinary course of business such as for alleged breaches of contract, miscalculation of royalties, employment matters, traffic accidents, pollution, contamination, encroachment on others' property or nuisance. The Company accrues for litigation, claims and proceedings when a liability is both probable and the amount can be reasonably estimated. As of December 31, 2020, the Company does not currently have any material amounts accrued related to litigation matters. For any matters not accrued for, it is not possible at this time to estimate the amount of any additional loss, or range of loss that is reasonably possible, but, based on the nature of the claims, management believes that current litigation, claims and proceedings, individually or in aggregate and after taking into account insurance, are not likely to have a material adverse impact on the Company's financial position, results of operations or cash flows, for the period in which the effect of that outcome becomes reasonably estimable. Many of these matters are in early stages, so the allegations and the damage theories have not been fully developed, and are all subject to inherent uncertainties; therefore, management's view may change in the future.

St. Lucie County Fire District Firefighters' Pension Trust

On October 17, 2016, the St. Lucie County Fire District Firefighters' Pension Trust filed a putative class action in the 61st District Court in Harris County, Texas, against the Company, certain of its former officers and current and former directors and the underwriters on behalf of itself and others that purchased certain depositary shares from the Company's January 2015 equity offering, alleging material misstatements and omissions in the registration statement for that offering. The Company removed the case to federal court, but after a decision by the United States Supreme Court in an unrelated case that these types of cases are not subject to removal, the federal court remanded the case to the Texas state court. The Texas trial court denied the Company's motion to dismiss, and in February 2020, the court of appeals declined to exercise discretion to reverse the trial court's decision. The Company filed a petition to review the trial court's decision with the Texas Supreme Court, and the Court requested a response from the plaintiff. The Court subsequently ordered full briefing on the merits of the case. The Company carries insurance for the claims asserted against it and the officer and director defendants, and the carrier has accepted coverage. The Company denies all allegations and intends to continue to defend this case vigorously. The Company does not expect this case to have a material adverse effect on the results of operations, financial position or cash flows of the Company. Additionally, it is not possible at this time to estimate the amount of any additional loss, or range of loss, that is reasonably possible.

Indemnifications

The Company has provided certain indemnifications to various third parties, including in relation to asset and entity dispositions, securities offerings and other financings, such as the St. Lucie County Fire District Firefighters' Pension Trust case described above. In the case of asset dispositions, these indemnifications typically relate to disputes, litigation or tax matters existing at the date of disposition. The Company likewise obtains indemnification for future matters when it sells assets, although there is no assurance the buyer will be capable of performing those obligations. In the case of equity offerings, these indemnifications typically relate to claims asserted against underwriters in connection with an offering. No material liabilities have been recognized in connection with these indemnifications.

(11) INCOME TAXES

The provision (benefit) for income taxes included the following components:

(in millions)	2020	2019	2018
Current:			
Federal	$ (2)	$ (1)	$ (5)
State	—	(1)	6
	(2)	(2)	1
Deferred:			
Federal	371	(431)	—
State	38	22	—
	409	(409)	—
Provision (benefit) for income taxes	$ 407	$ (411)	$ 1

The provision for income taxes was an effective rate of (15)% in 2020, (86)% in 2019 and 0% in 2018. The Company's effective tax rate increased in 2020, as compared with 2019, primarily due to the increase in the valuation allowance in 2020. The following reconciles the provision for income taxes included in the consolidated statements of operations with the provision which would result from application of the statutory federal tax rate to pre-tax financial income:

(in millions)	2020	2019	2018
Expected provision (benefit) at federal statutory rate	$ (568)	$ 101	$ 113
Increase (decrease) resulting from:			
State income taxes, net of federal income tax effect	(55)	11	13
Change in valuation allowance	1,034	(522)	(121)
Removal of sequestration fee on AMT receivables	—	—	(5)
Other	(4)	(1)	1
Provision (benefit) for income taxes	$ 407	$ (411)	$ 1

The 2020 tax accrual calculated under the estimated annual effective tax rate method reflects the Tax Reform Act changes that took effect January 1, 2018. The components of the Company's deferred tax balances as of December 31, 2020 and 2019 were as follows:

(in millions)	2020	2019
Deferred tax liabilities:		
Differences between book and tax basis of property	$ —	$ 312
Derivative activity	—	34
Right of use lease asset	38	37
Other	2	2
	40	385
Deferred tax assets:		
Differences between book and tax basis of property	295	—
Accrued compensation	38	33
Accrued pension costs	11	9
Asset retirement obligations	20	13
Net operating loss carryforward	1,117	769
Future lease payments	38	37
Derivative activity	9	—
Capital loss carryover	27	—
Other	24	18
	1,579	879
Valuation allowance	(1,539)	(87)
Net deferred tax asset	$ —	$ 407

The Tax Reform Act made significant changes to the U.S. federal income tax law affecting the Company. Major changes in this legislation applicable to the Company relate to the reduction in the corporate tax rate to 21%, repeal of the alternative minimum tax, interest deductibility and net operating loss carryforward limitations, changes to certain executive compensation and full expensing provisions related to business assets. The adjustments required to deferred taxes as a result of the Tax Reform Act have been reflected in the Company's tax provision.

As the Tax Reform Act repealed the corporate alternative minimum tax for tax years beginning on or after January 1, 2018 and provided for existing alternative minimum tax credit carryovers to be refunded beginning in 2018, the Company has approximately $30 million in refundable credits. Accordingly, in 2017 the valuation allowance in place prior to the Tax Reform Act related to these credits was released, and any credits remaining were reclassed to a receivable. Additionally, in January 2020 the IRS announced that any previously sequestered amounts relating to these alternative minimum tax refunds would also be refunded. The Company had approximately $2 million in sequestered amounts relating to alternative minimum tax refunds. All of those refunds have been received as of December 2020 after the CARES Act (enacted in March 2020) accelerated alternative minimum tax refunds.

In 2020, the Company received refunds related to federal income tax of $32 million. The Company received a refund of $1 million in state income tax in 2019 and paid $6.3 million in state income tax in 2018. The Company's net operating loss carryforward as of December 31, 2020 was $4.5 billion and $2 billion for federal and state reporting purposes, respectively, the majority of which will expire between 2035 and 2039. Included in the Company's net operating loss carryforward are the net operating loss carryforwards acquired in the Montage acquisition of $1 billion. A portion of the Montage-related net operating loss carryovers are subject to an annual section 382 limitation of $1.7 million, and the Company has appropriately accounted for this limitation in purchase accounting. In addition, certain net operating loss carryovers are subject to a section 382 limitation of $90 million, but the Company does not expect this limit to have a material impact on its net operating loss carryforward balance. Additionally, the Company has an income tax net operating loss carryforward related to its Canadian operations of $29 million, with expiration dates of 2030 through 2039. The Company also had a statutory depletion carryforward of $13 million and $55 million related to interest deduction carryforward as of December 31, 2020.

A valuation allowance for deferred tax assets, including net operating losses, is recognized when it is more likely than not that some or all of the benefit from the deferred tax assets will not be realized. To assess that likelihood, the Company uses estimates and judgment regarding future taxable income, and considers the tax consequences in the jurisdiction where such taxable income is generated, to determine whether a valuation allowance is required. Such evidence can include current financial position, results of operations, both actual and forecasted, the reversal of deferred tax liabilities, and tax planning strategies as well as current and forecasted business economics of the oil and gas industry.

Due to unexpected significant pricing declines resulting from the effects of COVID-19 and developments related to Russia/ OPEC, as well as the general oversupply of the market along with the material write-down of the carrying value of the Company's natural gas and oil properties, in addition to other negative evidence, the Company concluded that it was more likely than not that these deferred tax assets will not be realized and recorded a discrete tax expense of $408 million for the increase in its valuation allowance in the first quarter of 2020. The net change in valuation allowance is reflected as a component of income tax expense. The Company also has retained a valuation allowance of $87 million related to net operating losses in jurisdictions in which it no longer operates. Management will continue to assess available positive and negative evidence to estimate whether sufficient future taxable income will be generated to permit the use of deferred tax assets. The amount of the deferred tax asset considered realizable, however, could be adjusted based on changes in subjective estimates of future taxable income or if objective negative evidence is no longer present.

For the years ended December 31, 2018 and 2017, the Company maintained a full valuation allowance against its deferred tax assets based on its conclusion, considering all available evidence (both positive and negative), that it was more likely than not that the deferred tax assets would not be realized. A significant item of objective negative evidence considered was the cumulative pre-tax loss incurred over the three-year period ended December 31, 2018, primarily due to non-cash impairments of proved natural gas and oil properties recognized in 2015 and 2016. As of the first quarter of 2019, the Company had sustained a three-year cumulative level of profitability. Based on this factor and other positive evidence including forecasted taxable income, the Company concluded that it was more likely than not that the deferred tax assets would be realized and determined that $522 million of the valuation allowance would be released during 2019. Accordingly, a tax benefit of $522 million was recorded.

A reconciliation of the changes to the valuation allowance is as follows:

(in millions)	2020	2019
Valuation allowance at beginning of year	$ 87	$ 609
Release of valuation allowance	—	(522)
Establishment of valuation allowance on opening deferred balance	408	—
Opening balance adjustments	6	—
Changes based on 2020 activity	626	—
Purchase accounting	412	—
Valuation allowance at end of year	$ 1,539	$ 87

A tax position must meet certain thresholds for any of the benefit of the uncertain tax position to be recognized in the financial statements. As of December 31, 2020, there were no unrecognized tax positions identified that would have a material effect on the effective tax rate. All positions booked as of December 31, 2018 were released in 2019 due to audit completion and statute expirations.

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

(in millions)	2020	2019	2018
Unrecognized tax benefits at beginning of year	$ —	$ 7	$ 12
Additions based on tax positions related to the current year	$ —	$ —	$ —
Additions to tax positions of prior years	$ —	$ —	$ —
Reductions to tax positions of prior years	$ —	$ (7)	$ (5)
Unrecognized tax benefits at end of year	$ —	$ —	$ 7

The Internal Revenue Service closed the 2014 audit of the Company's federal return in 2019 with no change and is currently auditing the Company's 2016 and 2017 tax periods. The income tax years 2018 to 2020 remain open to examination by the major taxing jurisdictions to which the Company is subject.

(12) ASSET RETIREMENT OBLIGATIONS

The following table summarizes the Company's 2020 and 2019 activity related to asset retirement obligations:

(in millions)	2020	2019
Asset retirement obligation at January 1	$ 57	$ 61
Accretion of discount	4	3
Obligations incurred	1	2
Obligations assumed from Montage	28	—
Obligations settled/removed	(6)	(9)
Revisions of estimates	1	—
Asset retirement obligation at December 31	$ 85	$ 57
Current liability	$ 4	$ 6
Long-term liability	81	51
Asset retirement obligation at December 31	$ 85	$ 57

(13) RETIREMENT AND EMPLOYEE BENEFIT PLANS

401(k) Defined Contribution Plan

The Company has a 401(k) defined contribution plan covering eligible employees. The Company expensed $2 million, $2 million and $3 million of contribution expense in 2020, 2019 and 2018, respectively. Additionally, the Company capitalized $1 million of contributions in 2020 and $1 million and $2 million in 2019 and 2018, respectively, directly related to the acquisition, exploration and development activities of the Company's natural gas and oil properties or directly related to the construction of the Company's gathering systems.

Defined Benefit Pension and Other Postretirement Plans

Prior to January 1, 1998, the Company maintained a traditional defined benefit plan with benefits payable based upon average final compensation and years of service. Effective January 1, 1998, the Company amended its pension plan to become a "cash balance" plan on a prospective basis for its non-bargaining employees. A cash balance plan provides benefits based upon a fixed percentage of an employee's annual compensation. As part of ongoing effort to reduce costs, the Company has elected to freeze its pension plan effective January 1, 2021. Employees that were participants in the pension plan prior to January 1, 2021 will continue to receive the interest component of the plan but will no longer receive the service component. The Company's funding policy is to contribute amounts which are actuarially determined to provide the plans with sufficient assets to meet future benefit payment requirements and which are tax deductible.

The postretirement benefit plan provides contributory health care and life insurance benefits. Employees become eligible for these benefits if they meet age and service requirements. Generally, the benefits paid are a stated percentage of medical expenses reduced by deductibles and other coverages.

Prior to January 1, 2021, substantially all of the Company's employees were covered by the defined benefit pension. Substantially all of the Company's employees continue to be covered by the postretirement benefit plans. The Company accounts for its defined benefit pension and other postretirement plans by recognizing the funded status of each defined pension benefit plan and other postretirement benefit plan on the Company's balance sheet. In the event a plan is overfunded, the Company recognizes an asset. Conversely, if a plan is underfunded, the Company recognizes a liability.

In June 2018, the Company notified affected employees of a workforce reduction plan, which resulted primarily from a previously announced study of structural, process and organizational changes to enhance shareholder value. In December 2018, the Company closed the sale of the equity in certain of its subsidiaries that owned and operated its Fayetteville Shale E&P and related midstream gathering assets in Arkansas. As part of this transaction, many employees associated with those assets were either transferred to the buyer or their employment was terminated. As a result of the restructurings, the Company recognized a curtailment on its pension and other postretirement benefit plans and recognized a non-cash gain of $4 million on its consolidated statements of operations for the year ended December 31, 2018. In 2019, the Company recognized a $6 million non-cash settlement loss related to $21 million of lump sum payments as a result of these restructuring events. In 2020, the settlement loss was immaterial.

The following provides a reconciliation of the changes in the plans' benefit obligations, fair value of assets and funded status as of December 31, 2020 and 2019:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	2020	2019	2020	2019
Change in benefit obligations:				
Benefit obligation at January 1	$ 126	$ 125	$ 13	$ 13
Service cost	7	7	2	1
Interest cost	5	5	—	—
Participant contributions	—	—	—	—
Actuarial loss	16	15	1	1
Benefits paid	(13)	(2)	(1)	(2)
Plan amendments	—	—	(2)	—
Curtailments	(2)	—	—	—
Settlements	—	(24)	—	—
Benefit obligation at December 31	$ 139	$ 126	$ 13	$ 13

	Pension Benefits		Other Postretirement Benefits	
(in millions)	2020	2019	2020	2019
Change in plan assets:				
Fair value of plan assets at January 1	$ 96	$ 91	$ —	$ —
Actual return on plan assets	11	16	—	—
Employer contributions	12	12	1	2
Participant contributions	—	—	—	—
Benefits paid	(13)	(2)	(1)	(2)
Settlements	—	(21)	—	—
Fair value of plan assets at December 31	$ 106	$ 96	$ —	$ —
Funded status of plans at December 31	$ (33)	$ (30)	$ (13)	$ (13)

The Company uses a December 31 measurement date for all of its plans and had liabilities recorded for the underfunded status for each period as presented above.

The pension plans' projected benefit obligation, accumulated benefit obligation and fair value of plan assets as of December 31, 2020 and 2019 are as follows:

(in millions)	2020	2019
Projected benefit obligation	$ 139	$ 126
Accumulated benefit obligation	139	124
Fair value of plan assets	106	96

Pension and other postretirement benefit costs include the following components for 2020, 2019 and 2018:

	Pension Benefits			Other Postretirement Benefits		
(in millions)	2020	2019	2018	2020	2019	2018
Service cost	$ 7	$ 7	$ 10	$ 2	$ 1	$ 2
Interest cost	5	5	5	—	—	1
Expected return on plan assets	(6)	(6)	(7)	—	—	—
Amortization of transition obligation	—	—	—	—	—	—
Amortization of prior service cost	—	—	—	—	—	—
Amortization of net loss	1	2	2	—	—	—
Net periodic benefit cost	7	8	10	2	1	3
Curtailment gain	—	—	—	—	—	(4)
Settlement loss	—	6	—	—	—	—
Total benefit cost (benefit)	$ 7	$ 14	$ 10	$ 2	$ 1	$ (1)

Service cost is classified as general and administrative expenses on the consolidated statements of operations. All other components of total benefit cost (benefit) are classified as other income (loss), net on the consolidated statements of operations.

Amounts recognized in other comprehensive income for the years ended December 31, 2020 and 2019 were as follows:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	2020	2019	2020	2019
Net actuarial (loss) gain arising during the year	$ (12)	$ (5)	$ 2	$ (1)
Amortization of prior service cost	—	—	—	—
Amortization of net loss	1	2	—	—
Settlements	—	8	—	—
Curtailments	3	—	—	—
Tax effect	3	(1)	(1)	—
	$ (5)	$ 4	$ 1	$ (1)

Included in accumulated other comprehensive income as of December 31, 2020 and 2019 was a $36 million loss ($28 million net of tax) and a $30 million loss ($22 million net of tax), respectively, related to the Company's pension and other postretirement benefit plans. For the year ended December 31, 2020, $5 million was classified from accumulated other comprehensive income, primarily driven by actuarial losses. Amortization of prior period service cost reclassified from accumulated other comprehensive income to general and administrative expenses for the year was immaterial.

The amount in accumulated other comprehensive income that is expected to be recognized as a component of net periodic benefit cost during 2021 is a $1 million expense.

The assumptions used in the measurement of the Company's benefit obligations as of December 31, 2020 and 2019 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2020	2019	2020	2019
Discount rate	3.10 %	3.70 %	2.80 %	3.50 %
Rate of compensation increase	3.50 %	3.50 %	n/a	n/a

The assumptions used in the measurement of the Company's net periodic benefit cost for 2020, 2019 and 2018 are as follows:

	Pension Benefits			Other Postretirement Benefits		
	2020	2019	2018	2020	2019	2018
Discount rate	3.70 %	3.70 %	4.35 %	3.50 %	4.35 %	4.35 %
Expected return on plan assets	6.50 %	7.00 %	7.00 %	n/a	n/a	n/a
Rate of compensation increase	3.50 %	3.50 %	3.50 %	n/a	n/a	n/a

The expected return on plan assets for the various benefit plans is based upon a review of the historical returns experienced, combined with the future expected returns based upon the asset allocation strategy employed. The plans seek to achieve an adequate return to fund the obligations in a manner consistent with the federal standards of the Employee Retirement Income Security Act and with a prudent level of diversification.

For measurement purposes, the following trend rates were assumed for 2020 and 2019:

	2020	2019
Health care cost trend assumed for next year	6.5 %	7.0 %
Rate to which the cost trend is assumed to decline	5.0 %	5.0 %
Year that the rate reaches the ultimate trend rate	2037	2037

Assumed health care cost trend rates have a significant effect on the amounts for the health care plans. A one percentage point change in assumed health care cost trend rates would have the following effects:

(in millions)	1% Increase	1% Decrease
Effect on the total service and interest cost components	$ 2	$ (2)
Effect on postretirement benefit obligations	$ 2	$ (2)

Pension Payments and Asset Management

In 2020, the Company contributed $12 million to its pension plans and $1 million to its other postretirement benefit plan. The Company expects to contribute $13 million to its pension and other postretirement benefit plans in 2021.

The following benefit payments, which reflect projected future interest costs, are expected to be paid:

Pension Benefits		Other Postretirement Benefits	
	(in millions)		
2021	$ 5	2021	$ 1
2022	5	2022	1
2023	5	2023	1
2024	6	2024	1
2025	5	2025	1
Years 2026-2030	26	Years 2026-2030	4

The Company's overall investment strategy is to provide an adequate pool of assets to support both the long-term growth of plan assets and to ensure adequate liquidity exists for the near-term payment of benefit obligations to participants, retirees and beneficiaries. The Benefits Administration Committee of the Company, appointed by the Compensation Committee of the Board of Directors, administers the Company's pension plan assets. The Benefits Administration Committee believes long-term investment performance is a function of asset-class mix and restricts the composition of pension plan assets to a combination of cash and cash equivalents, domestic equity markets, international equity markets or investment grade fixed income assets.

The table below presents the allocations targeted by the Benefits Administration Committee and the actual weighted-average asset allocation of the Company's pension plan as of December 31, 2020, by asset category. The asset allocation targets are subject to change and the Benefits Administration Committee allows for its actual allocations to deviate from target as a result of current and anticipated market conditions. Plan assets are periodically balanced whenever the allocation to any asset class falls outside of the specified range.

	Pension Plan Asset Allocations	
Asset category:	Target	Actual
Equity securities:		
U.S. equity (1)	30 %	49 %
Non-U.S. equity (2)	30 %	17 %
Total equity securities	60 %	66 %
Fixed income (3)	35 %	32 %
Cash (4)	5 %	2 %
Total	100 %	100 %

(1) Includes the following equity securities in the table below: U.S. large cap growth equity, U.S. large cap value equity, U.S. large cap core equity, and U.S. small cap equity.

(2) Includes Non-U.S. equity securities in the table below.

(3) Includes fixed income pension plan assets in the table below.

(4) Includes Cash and cash equivalent pension plan assets in the table below.

Utilizing the fair value hierarchy described in Note 8, the Company's fair value measurement of pension plan assets as of December 31, 2020 is as follows:

(in millions)	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Measured within fair value hierarchy				
Equity securities:				
U.S. large cap value equity (1)	$ 10	$ 10	$ —	$ —
U.S. large cap core equity (2)	24	24	—	—
U.S. small cap equity (3)	13	13	—	—
Non-U.S. equity (4)	18	18	—	—
Fixed income (5)	34	34	—	—
Cash and cash equivalents	2	2	—	—
Total measured within fair value hierarchy	$ 101	$ 101	$ —	$ —
Measured at net asset value (6)				
Equity securities:				
U.S. large cap growth equity (7)	3			
U.S. small cap equity (3)	2			
Total measured at net asset value	$ 5			
Total plan assets at fair value	$ 106			

Note: Footnotes are located after the prior year comparative table below.

Utilizing the fair value hierarchy described in Note 8, the Company's fair value measurement of pension plan assets at December 31, 2019 was as follows:

(in millions)	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Measured within fair value hierarchy				
Equity securities:				
U.S. large cap growth equity (8)	$ 3	$ 3	$ —	$ —
U.S. large cap value equity (1)	6	6	—	—
U.S. small cap equity (3)	2	2	—	—
Non-U.S. equity (4)	32	32	—	—
Fixed income (5)	22	22	—	—
Cash and cash equivalents	2	2	—	—
Total measured within fair value hierarchy	$ 67	$ 67	$ —	$ —
Measured at net asset value (6)				
Equity securities:				
U.S. large cap growth equity (7)	3			
U.S. large cap core equity (2)	18			
Fixed income (5)	8			
Total measured at net asset value	$ 29			
Total plan assets at fair value	$ 96			

(1) Mutual fund that seeks to invest in a diversified portfolio of stocks that will increase in value over the long-term as well as provide current income.

(2) An institutional fund that seeks to replicate the performance of the S&P 500 Index before fees.

(3) Mutual fund that seeks to invest in a diversified portfolio of stocks with small market capitalizations.

(4) Mutual funds that invest primarily in equity securities of companies domiciled outside of the United States, primarily in developed markets.

(5) Institutional funds that seek an investment return that approximates, as closely as practicable, before expenses, the performance of the Barclays U.S. Intermediate Credit Bond Index over the long term and the Barclays Long U.S. Corporate Bond Index over the long-term.

(6) Plan assets for which fair value was measured using net asset value as a practical expedient.

(7) An institutional fund that seeks to invest in companies with sustainable competitive advantages, as identified through proprietary research.

(8) Mutual fund that seeks to invest in a diversified portfolio of stocks with price appreciation growth opportunities.

The Company's pension plan assets that are classified as Level 1 are the investments comprised of either cash or investments in open-ended mutual funds which produce a daily net asset value that is validated with a sufficient level of observable activity to support classification of the fair value measurement as Level 1. Due to the Company's implementation of Accounting Standards Update No. 2015-07, assets measured using net asset value as a practical expedient have not been classified in the fair value hierarchy. No concentration of risk arising within or across categories of plan assets exists due to any significant investments in a single entity, industry, country or investment fund.

(14) LONG-TERM INCENTIVE COMPENSATION

The Southwestern Energy Company 2013 Incentive Plan was adopted in February 2013, approved by stockholders in May 2013 and amended and restated per stockholders' approval in May 2016 and further amended in May 2017 and May 2019 (the "2013 Plan"). The 2013 Plan provides for the compensation of officers, key employees and eligible non-employee directors of the Company and its subsidiaries.

The 2013 Plan provides for grants of options, stock appreciation rights, and shares of restricted stock and restricted stock units to employees, officers and directors that, in the aggregate, do not exceed 88,700,000 shares. The types of incentives that may be awarded are comprehensive and are intended to enable the Company's Board of Directors to structure the most appropriate incentives and to address changes in income tax laws which may be enacted over the term of the 2013 Plan.

The Company's stock-based compensation is classified as either equity or liability awards in accordance with GAAP. The fair value of an equity-classified award is determined at the grant date and is amortized to general and administrative expense and capitalized expense on a straight-line basis over the vesting period of the award. The fair value of a liability-classified award is determined on a quarterly basis beginning at the grant date until final vesting. Changes in the fair value of liability-classified awards are recorded to general and administrative expense over the vesting period of the award. A portion of this general and administrative expense is capitalized into natural gas and oil properties, included in property and equipment. Generally, stock options granted to employees and directors vest ratably over three years from the grant date and expire seven years from the date of grant. The Company issues shares of restricted stock or restricted stock units to employees and directors which generally vest over four years. Restricted stock, restricted stock units and stock options granted to participants under the 2013 Plan, as amended and restated, immediately vest upon death, disability or retirement (subject to a minimum of three years of service). The Company issues performance units which have historically vested over three years to employees. The performance units granted in 2018, 2019 and 2020 cliff-vest at the end of three years.

In June 2018, the Company announced a workforce reduction. Unvested stock-based awards of the affected employees were subsequently cancelled and the approximate fair value of a portion of those cancelled awards was included in a cash severance payment that was paid in the third quarter of 2018. Stock-based compensation costs recognized prior to the cancellation as either general and administrative expense or capitalized expense were reversed and the severance payments were subsequently recognized as restructuring charges for the year ended December 31, 2018 on the consolidated statements of operations.

In December 2018, the Company closed the Fayetteville Shale sale. As part of this transaction, most employees associated with those assets became employees of the buyer although the employment of some was terminated. All affected employees were offered a severance package, which included a one-time cash payment depending on length of service and, if applicable, the current value of a portion of equity awards that were forfeited. Stock-based compensation costs recognized prior to the cancellation as either general and administrative expense or capitalized expense were reversed and the severance payments were subsequently recognized as restructuring charges for the years ended December 31, 2019 and 2018 on the consolidated statements of operations.

In February 2020, the Company announced a strategic realignment of the Company's organizational structure. Affected employees were offered a severance package, which included a one-time payment depending on length of service and, if applicable, the current value of unvested long-term incentive awards that were forfeited. The Company also recognized additional severance costs in the fourth quarter of 2020 related to continued organizational restructuring. Stock-based compensation costs recognized prior to the cancellation as either general and administrative expense or capitalized expense were reversed and the severance payments were subsequently recognized as restructuring charges for the year ended December 31, 2020 on the consolidated statements of operations.

Equity-Classified Awards

Equity-Classified Stock Options

The Company recorded the following compensation costs related to stock options for the years ended December 31, 2020, 2019 and 2018:

(in millions)	2020	2019	2018
Stock options – general and administrative expense	$ —	$ 1	$ 2
Stock options – general and administrative expense capitalized	$ —	$ —	$ —

The Company recorded no deferred tax assets related to stock options for the year ended December 31, 2020, compared to deferred tax assets of less than $1 million for the years ended December 31, 2019 and 2018. Additionally, the Company had no unrecognized compensation cost related to unvested stock options at December 31, 2020.

The fair value of stock options is estimated on the date of the grant using a Black-Scholes valuation model that uses the weighted average assumptions noted in the following table. Expected volatility is based on historical volatility of the Company's common stock and other factors. The Company uses historical data on the exercise of stock options, post-vesting forfeitures and other factors to estimate the expected term of the stock-based payments granted. The risk-free interest rate is based on the U.S. Treasury yield curve in effect at the time of grant. The Company did not issue equity-classified stock options in 2020, 2019 or 2018.

The following tables summarize stock option activity for the years 2020, 2019 and 2018, and provide information for options outstanding at December 31 of each year:

	2020		2019		2018	
	Number of Shares	Weighted Average Exercise Price	Number of Shares	Weighted Average Exercise Price	Number of Shares	Weighted Average Exercise Price
	(in thousands)		*(in thousands)*		*(in thousands)*	
Options outstanding at January 1	4,635	$ 15.26	5,178	$ 17.06	6,020	$ 19.43
Granted	—	$ —	—	$ —	—	$ —
Exercised	—	$ —	—	$ —	—	$ —
Forfeited or expired	(785)	$ 24.46	(543)	$ 32.38	(842)	$ 33.99
Options outstanding at December 31	3,850	$ 13.39	4,635	$ 15.26	5,178	$ 17.06

	Options Outstanding			Options Exercisable		
Range of Exercise Prices	Options Outstanding at December 31, 2020	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Options Exercisable at December 31, 2020	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life
	(in thousands)		*(years)*	*(in thousands)*		*(years)*
$7.74-$29.42	3,126	$ 8.95	2.3	3,126	$ 8.95	2.3
$30.59-$35.64	634	$ 30.59	0.9	634	$ 30.59	0.9
$46.55-$46.55	90	$ 46.55	0.3	90	$ 46.55	0.3
	3,850	$ 13.39	2.0	3,850	$ 13.39	2.0

No options were granted or exercised in 2020, 2019 or 2018.

Equity-Classified Restricted Stock

The Company recorded the following compensation costs related to restricted stock grants for the years ended December 31, 2020, 2019 and 2018:

(in millions)	2020	2019	2018
Restricted stock grants – general and administrative expense	$ 3	$ 6	$ 9
Restricted stock grants – general and administrative expense capitalized	$ 1	$ 4	$ 5

The Company also recorded deferred tax asset of $2 million related to restricted stock for the year ended December 31, 2020, compared to a reduction in the deferred tax assets of less than $1 million and deferred tax asset of $2 million for the years end

2019 and 2018, respectively. As of December 31, 2020, there was $1 million of total unrecognized compensation cost related to unvested shares of restricted stock that is expected to be recognized over a weighted-average period of less than one year.

The following table summarizes the restricted stock activity for the years 2020, 2019 and 2018, and provides information for restricted stock outstanding at December 31 of each year:

	2020		2019		2018	
	Number of Shares	Weighted Average Fair Value	Number of Shares	Weighted Average Fair Value	Number of Shares	Weighted Average Fair Value
	(in thousands)		*(in thousands)*		*(in thousands)*	
Unvested shares at January 1	1,480	$ 7.00	2,717	$ 7.91	6,254	$ 8.85
Granted	584	$ 2.86	493	$ 3.06	350	$ 4.72
Vested	(1,098)	$ 5.26	(1,516)	$ 7.16	(2,058)	$ 9.24
Forfeited	(269) (1)	$ 7.79	(214) (2)	$ 8.38	(1,829) (3)	$ 9.01
Unvested shares at December 31	697	$ 5.97	1,480	$ 7.00	2,717	$ 7.91

(1) Includes 171,813 shares forfeited as a result of the reduction in workforce for the year end December 31, 2020.

(2) Includes 65,196 shares forfeited as a result of the reduction in workforce for the year ended December 31, 2019.

(3) Includes 1,287,636 shares forfeited as a result of the reduction in workforce for the year ended December 31, 2018.

The fair values of the grants were $2 million for 2020, $2 million for 2019 and $2 million for 2018. The total fair value of shares vested were $6 million for 2020, $11 million for 2019 and $19 million for 2018.

Equity-Classified Restricted Stock Units

As a result of the Merger with Montage, certain Montage employees became employees of Southwestern and retained their original equity awards. The amount of compensation costs related these equity-classified restricted stock units recorded by the Company was immaterial for the year ended December 31, 2020. As of December 31, 2020, there was less than $1 million of total unrecognized compensation cost related to unvested equity-classified restricted stock units that is expected to be recognized over a weighted-average period of approximately one year.

The following table summarizes equity-classified restricted stock unit activity to be paid out in Company stock for the year ended December 31, 2020.

	Number of Units	Weighted Average Fair Value
	(in thousands)	
Unvested Units at January 1, 2020	—	$ —
Granted	186	$ 3.05
Vested	(42)	$ 3.05
Forfeited	(10)	$ 3.05
Unvested Units at December 31, 2020	**134**	**$ 3.05**

Equity-Classified Performance Units

The Company recorded compensation costs related to equity-classified performance units for the years ended December 31, 2020, 2019 and 2018. The performance units awarded in 2017 included a market condition based on relative Total Shareholder Return ("TSR"). The grant date fair value is calculated using the closing price of the Company's common stock at the grant date and a Monte Carlo model to estimate the TSR market condition. The estimated fair value is amortized to compensation expense on a straight-line basis over the vesting period of the award. There were no equity-classified performance units awarded in 2020, 2019 or 2018.

(in millions)	2020	2019	2018
Performance units – general and administrative expense	$ —	$ 1	$ 3
Performance units – general and administrative expense capitalized	$ —	$ —	$ 1

The Company also recorded a deferred tax asset of less than $1 million related to equity-classified performance units for the year ended December 31, 2020, compared to deferred tax assets of less than $1 million and $1 million in 2019 and 2018, respectively. As of December 31, 2020, there are no more equity-classified performance units outstanding.

The following table summarizes equity-classified performance unit activity to be paid out in Company stock for the years ended December 31, 2020, 2019 and 2018, and provides information for unvested units as of December 31, 2020, 2019 and 2018:

	2020			2019			2018		
	Number of Units (1)		Weighted Average Fair Value	Number of Units (1)		Weighted Average Fair Value	Number of Units (1)		Weighted Average Fair Value
	(in thousands)			*(in thousands)*			*(in thousands)*		
Unvested units at January 1	178	$	10.47	598	$	10.01	1,084	$	10.12
Granted	—	$	—	—	$	—	—	$	—
Vested	(178)	$	10.47	(378)	$	9.59	(290)	$	10.47
Forfeited	—	$	—	(42) (2)	$	10.47	(196) (3)	$	9.94
Unvested shares at December 31	—	$	—	178	$	10.47	598	$	10.01

(1) These amounts reflect the number of performance units granted in thousands. The actual payout of shares may range from a minimum of zero shares to a maximum of two shares per unit contingent upon TSR. The performance units have a three-year vesting term and the actual disbursement of shares, if any, is determined during the first quarter following the end of the three-year vesting period.

(2) Includes 41,761 units related to the reduction in workforce for the year ended December 31, 2019.

(3) Includes 144,927 units related to the reduction in workforce for the year ended December 31, 2018.

Liability-Classified Awards

Liability-Classified Restricted Stock Units

In the first quarter of 2019 and 2018, the Company granted restricted stock units that vest over a period of four years and are payable in either cash or shares at the option of the Compensation Committee of the Company's Board of Directors. The Company has accounted for these as liability-classified awards, and accordingly changes in the market value of the instruments will be recorded to general and administrative expense and capitalized expense over the vesting period of the award.

(in millions)	2020		2019		2018	
Restricted stock units – general and administrative expense	$	5	$	7	$	4
Restricted stock units – general and administrative expense capitalized	$	2	$	5	$	3

The Company also recorded deferred tax assets of $1 million for the year ended December 31, 2020, compared to less than $1 million and $2 million related to liability-classified restricted stock units for the years ended 2019 and 2018, respectively. As of December 31, 2020, there was $22 million of total unrecognized compensation cost related to liability-classified restricted stock units that is expected to be recognized over a weighted-average period of two years. The amount of unrecognized compensation cost for liability-classified awards will fluctuate over time as they are marked to market.

The following table summarizes restricted stock unit activity to be paid out in cash for the years ended December 31, 2020 and 2019 and provides information for unvested units as of December 31, 2020 and 2019:

	2020			2019			2018		
	Number of Units		Weighted Average Fair Value	Number of Units		Weighted Average Fair Value	Number of Units		Weighted Average Fair Value
	(in thousands)			*(in thousands)*			*(in thousands)*		
Unvested units at January 1	12,992	$	2.42	8,202	$	3.41	—	$	—
Granted	6,172	$	1.41	8,659	$	4.34	12,216	$	3.69
Vested	(3,960)	$	1.43	(2,624)	$	4.09	(232)	$	5.14
Forfeited	(3,591) (1)	$	2.67	(1,245) (2)	$	3.48	(3,782) (3)	$	4.86
Unvested units at December 31	11,613	$	2.67	12,992	$	2.42	8,202	$	3.41

(1) Includes 2,010,196 units related to the reduction in workforce for the year ended December 31, 2020.

(2) Includes 400,056 units related to the reduction in workforce for the year ended December 31, 2019.

(3) Includes 2,766,610 units related to the reduction in workforce for the year ended December 31, 2018.

Liability-Classified Performance Units

In 2020, 2019 and 2018 the Company granted performance units that vest at the end of, or over, a three-year period and are payable in either cash or shares at the option of the Compensation Committee of the Company's Board of Directors. The

Company has accounted for these as liability-classified awards, and accordingly changes in the fair market value of the instruments will be recorded to general and administrative expense and capitalized expense over the vesting period of the awards. The performance unit awards granted in 2018 include a performance condition based on cash flow per debt-adjusted share and two market conditions, one based on absolute TSR and the other on relative TSR as compared to a group of the Company's peers. The performance unit awards granted in 2019 include a performance condition based on return on average capital employed and two market conditions, one based on absolute TSR and the other on relative TSR. The performance unit awards granted in 2020 include a performance condition based on return on average capital employed and a market condition based on relative TSR. The fair values of all market conditions discussed above are calculated by Monte Carlo models on a quarterly basis.

(in millions)	2020	2019	2018
Liability-classified performance units – general and administrative expense	$ 7	$ 2	$ 2
Liability-classified performance units – general and administrative expense capitalized	$ 2	$ 1	$ —

The Company also recorded deferred tax assets of $2 million related to liability-classified performance units for the year ended December 31, 2020, compared to a reduction of deferred tax asset of less than $1 million and a deferred tax asset of $1 million for the years ended 2019 and 2018, respectively. As of December 31, 2020, there was $14 million of total unrecognized compensation cost related to liability-classified performance units. This cost is expected to be recognized over a weighted-average period of two years. The amount of unrecognized compensation cost for liability-classified awards will fluctuate over time as they are marked to market. The final value of the performance unit awards is contingent upon the Company's actual performance against the Performance Measures.

The following table summarizes liability-classified performance unit activity to be paid out in cash or stock for the years ended December 31, 2020, 2019 and 2018 and provides information for unvested units as of December 31, 2020, 2019 and 2018:

	2020		2019		2018	
	Number of Units *(in thousands)*	Weighted Average Fair Value	Number of Units *(in thousands)*	Weighted Average Fair Value	Number of Units *(in thousands)*	Weighted Average Fair Value
Unvested units at January 1	5,142	$ 2.42	2,803	$ 3.41	—	$ —
Granted	6,172	$ 1.41	2,757	$ 4.34	3,200	$ 3.70
Vested	—	$ —	(43)	$ 2.42	—	$ —
Forfeited	(2,615) (1)	$ 3.05	(375) (2)	$ 3.12	(397) (3)	$ 4.55
Unvested units at December 31	8,699	$ 2.57	5,142	$ 2.42	2,803	$ 3.41

(1) Includes 518,450 units related to the reduction in workforce for the year ended December 31, 2020.

(2) Includes 375,086 units related to the reduction in workforce for the year ended December 31, 2019.

(3) Includes 295,160 units related to the reduction in workforce for the year ended December 31, 2018.

Cash-Based Compensation

Performance Cash Awards

In 2020, the Company granted performance cash awards that vest over a four-year period and are payable in cash on an annual basis. The value of each unit of the award equal one dollar. The Company recognizes the cost of these awards as general and administrative expense, operating expense and capitalized expense over the vesting period of the awards. The performance cash awards granted in 2020 include a performance condition determined annually by the Company. In 2020, the performance measure is a targeted discretionary cash flow amount. If the Company, in its sole discretion, determines that the threshold was not met, the amount for that vesting period will not vest and will be cancelled.

	Number of Units		Weighted Average Fair Value
	(in thousands)		
Unvested units at January 1, 2020	—	$	—
Granted	20,044	$	1.00
Vested	(100)	$	1.00
Forfeited	(1,591) [1]	$	1.00
Unvested Units at December 31, 2020	18,353	$	1.00

(1) Includes 945,500 units related to the reduction in workforce for the year ended December 31, 2020.

The Company also recorded a deferred tax asset of $1 million related to performance cash awards for the year ended December 31, 2020. As of December 31, 2020 there was $14 million of total unrecognized compensation cost related to performance cash awards. This cost is expected to be recognized over a weighted average 3.2 years. The final value of the performance cash awards is contingent upon the Company's actual performance against these performance measures.

(15) SEGMENT INFORMATION

The Company’s reportable business segments have been identified based on the differences in products or services provided. Revenues for the E&P segment are derived from the production and sale of natural gas and liquids. The Marketing segment generates revenue through the marketing of both Company and third-party produced natural gas and liquids volumes.

Summarized financial information for the Company’s reportable segments is shown in the following table. The accounting policies of the segments are the same as those described in Note 1. Management evaluates the performance of its segments based on operating income, defined as operating revenues less operating costs. Income before income taxes, for the purpose of reconciling the operating income amount shown below to consolidated income before income taxes, is the sum of operating income (loss), interest expense, gain (loss) on derivatives, gain (loss) on early extinguishment of debt and other income (loss). The “Other” column includes items not related to the Company’s reportable segments, including real estate and corporate items.

(in millions)	Exploration and Production		Marketing		Other	**Total**
2020						
Revenues from external customers	$ 1,391		$ 917		$ —	**$ 2,308**
Intersegment revenues	(43)		1,228		—	**1,185**
Depreciation, depletion and amortization expense	348		9		—	**357**
Impairments	2,830		—		—	**2,830**
Operating loss	(2,864)	(1)	(7)		—	**(2,871)**
Interest expense (2)	94		—		—	**94**
Gain on derivatives	224		—		—	**224**
Gain on early extinguishment of debt	—		—		35	**35**
Other income, net	—		—		1	**1**
Provision for income taxes (2)	407		—		—	**407**
Assets	4,654	(3)	381		125	**5,160**
Capital investments (4)	899		—		—	**899**
2019						
Revenues from external customers	$ 1,740		$ 1,298		$ —	**$ 3,038**
Intersegment revenues	(37)		1,552		—	**1,515**
Depreciation, depletion and amortization expense	462		9		—	**471**
Impairments	13		3		—	**16**
Operating income (loss)	283	(5)	(13)		—	**270**
Interest expense (2)	65		—		—	**65**
Gain on derivatives	274		—		—	**274**
Gain on early extinguishment of debt	—		—		8	**8**
Other income (loss), net	(9)		—		2	**(7)**
Benefit from income taxes (2)	(411)		—		—	**(411)**
Assets	6,235	(3)	314		168	**6,717**
Capital investments (4)	1,138		—		2	**1,140**
2018 (6)						
Revenues from external customers	$ 2,551		$ 1,311		$ —	**$ 3,862**
Intersegment revenues	(26)		2,434		—	**2,408**
Depreciation, depletion and amortization expense	514		46		—	**560**
Impairments	15		155	(8)	1	**171**
Operating income (loss)	794	(7)	4	(9)	(1)	**797**
Interest expense (2)	124		—		—	**124**
Loss on derivatives	(118)		—		—	**(118)**
Loss on early extinguishment of debt	—		—		(17)	**(17)**
Other income (loss)	2		(2)		—	**—**
Provision for income taxes (2)	1		—		—	**1**
Assets	4,872	(3)	539		386	**5,797**
Capital investments (4)	1,231		9		8	**1,248**

(1) Operating income for the E&P segment includes $16 million of restructuring charges and $41 million of acquisition-related charges for the year ended December 31, 2020.

(2) Interest expense and the provision (benefit) for income taxes by segment are an allocation of corporate amounts as they are incurred at the corporate level.

(3) E&P assets includes office, technology, water infrastructure, drilling rigs and other ancillary equipment not directly related to natural gas and oil properties. This also includes deferred tax assets which are an allocation of corporate amounts as they are incurred at the corporate level.

(4) Capital investments include a decrease of $3 million for 2020, an increase of $34 million for 2019 and a decrease of $53 million for 2018 related to the change in accrued expenditures between years.

(5) Operating income for the E&P segment includes $11 million of restructuring charges for the year ended December 31, 2019.

(6) Includes the impact of approximately eleven months of Fayetteville Shale-related E&P and midstream gathering operations which were divested in December 2018.

(7) Operating income for the E&P segment includes $37 million related to restructuring charges for the year ended December 31, 2018.

(8) Marketing includes a $10 million non-cash impairment related to certain non-core midstream gathering assets at December 31, 2018.

(9) Operating income for the Marketing segment includes $2 million related to restructuring charges for the year ended December 31, 2018.

The following table presents the breakout of other assets, which represent corporate assets not allocated to segments and assets for non-reportable segments for the years ended December 31, 2020, 2019 and 2018:

(in millions)	For the years ended December 31, 2020	2019	2018
Cash and cash equivalents	$ 13	$ 5	$ 205
Accounts receivable	1	—	4
Income taxes receivable	—	30	89
Current hedging asset	—	—	1
Prepayments	6	8	8
Property, plant and equipment	16	27	60
Unamortized debt expense	11	11	11
Right-of-use lease assets	72	80	—
Non-qualified retirement plan	6	7	8
	$ 125	$ 168	$ 386

Included in intersegment revenues of the Marketing segment are $1.2 billion, $1.6 billion and $2.3 billion for 2020, 2019 and 2018, respectively, for marketing of the Company's E&P sales. Corporate assets include cash and cash equivalents, furniture and fixtures and other costs. Corporate general and administrative costs, depreciation expense and taxes other than income are allocated to the segments.

SUPPLEMENTAL QUARTERLY RESULTS (UNAUDITED)

The following is a summary of the quarterly results of operations for the years ended December 31, 2020 and 2019:

(in millions, except share amounts)	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
		2020		
Operating revenues	$ 592	$ 410	$ 527	$ 779
Operating loss	(1,490)	(756)	(381)	(244)
Net loss	(1,547)	(880)	(593)	(92)
Loss per share – Basic	(2.86)	(1.63)	(1.04)	(0.14)
Loss per share – Diluted	(2.86)	(1.63)	(1.04)	(0.14)
		2019		
Operating revenues	$ 990	$ 667	$ 636	$ 745
Operating income (loss)	213	22	(29)	64
Net income	594	138	49	110
Earnings per share – Basic	1.10	0.26	0.09	0.20
Earnings per share – Diluted	1.10	0.26	0.09	0.20

SUPPLEMENTAL OIL AND GAS DISCLOSURES (UNAUDITED)

The Company's operating natural gas and oil properties are located solely in the United States. The Company also has licenses to properties in Canada, the development of which is subject to an indefinite moratorium. See "Our Operations – Other – New Brunswick, Canada" in Item 1 of Part 1 of this Annual Report.

Net Capitalized Costs

The following table shows the capitalized costs of natural gas and oil properties and the related accumulated depreciation, depletion and amortization as of December 31, 2020 and 2019:

(in millions)	2020	2019
Proved properties	$ 25,789	$ 23,744
Unproved properties	1,472	1,506
Total capitalized costs	27,261	25,250
Less: Accumulated depreciation, depletion and amortization	(23,362)	(20,203)
Net capitalized costs	$ 3,899	$ 5,047

Natural gas and oil properties not subject to amortization represent investments in unproved properties and major development projects in which the Company owns an interest. These unproved property costs include unevaluated costs associated with leasehold or drilling interests and unevaluated costs associated with wells in progress. The table below sets forth the composition of net unevaluated costs excluded from amortization as of December 31, 2020:

(in millions)	2020	2019	2018	Prior	**Total**
Property acquisition costs	$ 116	$ 44	$ 34	$ 1,022	**$ 1,216**
Exploration and development costs	17	17	14	20	**68**
Capitalized interest	62	47	33	46	**188**
	$ 195	$ 108	$ 81	$ 1,088	**$ 1,472**

Of the total net unevaluated costs excluded from amortization as of December 31, 2020, approximately $1.1 billion is related to undeveloped properties in Southwest Appalachia (acquired in 2014 and 2015), $88 million is related to the recently acquired Montage properties and approximately $6 million is related to the acquisition of undeveloped properties in Northeast Appalachia. Additionally, the Company has approximately $188 million of unevaluated capitalized interest and $61 million of unevaluated costs related to wells in progress. The remaining costs excluded from amortization are related to properties which are not individually significant and on which the evaluation process has not been completed. The timing and amount of property acquisition and seismic costs included in the amortization computation will depend on the location and timing of drilling wells, results of drilling and other assessments. The Company is, therefore, unable to estimate when these costs will be included in the amortization computation.

Costs Incurred in Natural Gas and Oil Exploration and Development

The table below sets forth capitalized costs incurred in natural gas and oil property acquisition, exploration and development activities:

(in millions, except per Mcfe amounts)	2020	2019	2018
Unproved property acquisition costs	$ 124 (1)	$ 162	$ 164
Exploration costs	—	2	5
Development costs	784	936	1,014
Capitalized costs incurred	$ 908	$ 1,100	$ 1,183
Full cost pool amortization per Mcfe	$ 0.38	$ 0.56	$ 0.51

(1) Excludes $90 million of unevaluated property acquisition costs associated with the non-cash Montage Merger.

Capitalized interest is included as part of the cost of natural gas and oil properties. The Company capitalized $88 million, $109 million and $115 million during 2020, 2019 and 2018, respectively, based on the Company's weighted average cost of borrowings used to finance expenditures.

In addition to capitalized interest, the Company capitalized internal costs totaling $56 million, $77 million and $90 million during 2020, 2019 and 2018, respectively, which were directly related to the acquisition, exploration and development of the Company's natural gas and oil properties.

Results of Operations from Natural Gas and Oil Producing Activities

The table below sets forth the results of operations from natural gas and oil producing activities:

(in millions)	2020	2019	2018
Sales	$ 1,348	$ 1,703	$ 2,525
Production (lifting) costs	(866)	(781)	(974)
Depreciation, depletion and amortization	(348)	(462)	(514)
Impairment of natural gas and oil properties	(2,825)	—	—
	(2,691)	460	1,037
Provision for income taxes (1)	—	110	—
Results of operations (2)	$ (2,691)	$ 350	$ 1,037

(1) Prior to the recognition of a valuation allowance, in 2020 and 2018 the Company recognized an income tax provision (benefit) of ($624) million and $254 million, respectively.

(2) Results of operations exclude the gain (loss) on unsettled commodity derivative instruments. See Note 6.

The results of operations shown above exclude general and administrative expenses and interest expense and are not necessarily indicative of the contribution made by the Company's natural gas and oil operations to its consolidated operating results. Income tax expense is calculated by applying the statutory tax rates to the revenues less costs, including depreciation, depletion and amortization, and after giving effect to permanent differences and tax credits.

Natural Gas and Oil Reserve Quantities

The Company engaged the services of Netherland, Sewell & Associates, Inc., or NSAI, an independent petroleum engineering firm, to audit the reserves estimated by the Company's reservoir engineers. In conducting its audit, the engineers and geologists of NSAI studied the Company's major properties in detail and independently developed reserve estimates. NSAI's audit consists primarily of substantive testing, which includes a detailed review of the Company's major properties, and accounted for approximately 97% of the present worth of the Company's total proved reserves as of December 31 of 2020. For 2019 and 2018, NSAI's audit accounted for 99% of the present worth of the Company's total proved properties. A reserve audit is not the same as a financial audit, and a reserve audit is less rigorous in nature than a reserve report prepared by an independent petroleum engineering firm containing its own estimate of reserves. Reserve estimates are inherently imprecise, and the Company's reserve estimates are generally based upon extrapolation of historical production trends, historical prices of natural gas and crude oil and analogy to similar properties and volumetric calculations. Accordingly, the Company's estimates are expected to change, and such changes could be material and occur in the near term as future information becomes available.

The following table summarizes the changes in the Company's proved natural gas, oil and NGL reserves for 2020, 2019 and 2018, all of which were located in the United States:

	Natural Gas *(Bcf)*	Oil *(MBbls)*	NGL *(MBbls)*	**Total** ***(Bcfe)***
December 31, 2017	**11,126**	**65,636**	**542,455**	**14,775**
Revisions of previous estimates due to price	96	788	8,912	**154**
Revisions of previous estimates other than price	316	410	8,855	**372**
Extensions, discoveries and other additions	753	5,830	36,823	**1,009**
Production	(807)	(3,407)	(19,706)	**(946)**
Acquisition of reserves in place	—	—	—	**—**
Disposition of reserves in place (1)	(3,440)	(250)	(276)	**(3,443)**
December 31, 2018	**8,044**	**69,007**	**577,063**	**11,921**
Revisions of previous estimates due to price	(480)	(2,041)	(37,492)	**(717)**
Revisions of previous estimates other than price (2)	685	3,707	65,869	**1,102**
Extensions, discoveries and other additions	992	6,948	26,941	**1,195**
Production	(609)	(4,696)	(23,620)	**(778)**
Acquisition of reserves in place	—	—	—	**—**
Disposition of reserves in place	(2)	—	—	**(2)**
December 31, 2019	**8,630**	**72,925**	**608,761**	**12,721**
Revisions of previous estimates due to price	(2,143)	(32,507)	(338,639)	**(4,370)**
Revisions of previous estimates other than price	763	3,816	106,444	**1,424**
Extensions, discoveries and other additions	714	135	4,371	**741**
Production	(694)	(5,141)	(25,927)	**(880)**
Acquisition of reserves in place (3)	1,911	18,796	55,141	**2,354**
Disposition of reserves in place	—	—	—	**—**
December 31, 2020	**9,181**	**58,024**	**410,151**	**11,990**

(1) The 2018 disposition is primarily associated with the Fayetteville Shale sale.

(2) For the year ended December 31, 2019, revisions of previous estimates other than price includes 109 Bcfe of proved undeveloped reserves reclassified to unproved due to changes in the drilling plan, in accordance with the SEC five-year rule.

(3) The 2020 acquisition is primarily associated with the Montage Merger.

	Natural Gas *(Bcf)*	Oil *(MBbls)*	NGL *(MBbls)*	**Total** ***(Bcfe)***
Proved developed reserves as of:				
December 31, 2018	4,395	18,037	175,480	**5,557**
December 31, 2019	4,906	26,124	226,271	**6,421**
December 31, 2020	**6,342**	**33,563**	**276,548**	**8,203**
Proved undeveloped reserves as of:				
December 31, 2018	3,649	50,970	401,583	**6,364**
December 31, 2019	3,724	46,801	382,490	**6,300**
December 31, 2020	**2,839**	**24,461**	**133,603**	**3,787**

The Company's estimated proved natural gas, oil and NGL reserves were 11,990 Bcfe at December 31, 2020, compared to 12,721 Bcfe at December 31, 2019. The Company's reserves decreased in 2020, compared to 2019, as acquisitions, non-price revisions, positive extensions, discoveries and other additions in Appalachia were more than offset by negative price revisions and production. The increase in non-price revisions at December 31, 2020 resulted primarily from increased well performance and lower operating costs.

The increase in the Company's reserves in 2019 primarily resulted from the positive extensions, discoveries, other additions and revisions in Appalachia were only partially offset by negative price revisions. The decrease in the Company's reserves in 2018 primarily resulted from the disposition of the reserves related to the Fayetteville Shale and was only partially offset by positive extensions, discoveries, other additions and revisions in Appalachia.

The following table summarizes the changes in reserves for 2018, 2019 and 2020:

	Appalachia		Fayetteville		
(in Bcfe)	Northeast	Southwest	Shale [(1)]	Other [(2)]	**Total**
December 31, 2017	**4,126**	**6,962**	**3,679**	**8**	**14,775**
Net revisions					
Price revisions	41	106	6	1	**154**
Performance and production revisions	107	272	(6)	(1)	**372**
Total net revisions	148	378	—	—	**526**
Extensions, discoveries and other additions					
Proved developed	154	22	1	—	**177**
Proved undeveloped	397	435	—	—	**832**
Total reserve additions	551	457	1	—	**1,009**
Production	(459)	(243)	(243)	(1)	**(946)**
Acquisition of reserves in place	—	—	—	—	**—**
Disposition of reserves in place	—	—	(3,437)	(6)	**(3,443)**
December 31, 2018	**4,366**	**7,554**	**—**	**1**	**11,921**
Net revisions					
Price revisions	(57)	(660)	—	—	**(717)**
Performance and production revisions [(3)]	127	975	—	—	**1,102**
Total net revisions	70	315	—	—	**385**
Extensions, discoveries and other additions					
Proved developed	185	6	—	—	**191**
Proved undeveloped	677	327	—	—	**1,004**
Total reserve additions	862	333	—	—	**1,195**
Production	(459)	(319)	—	—	**(778)**
Acquisition of reserves in place	—	—	—	—	**—**
Disposition of reserves in place	(2)	—	—	—	**(2)**
December 31, 2019	**4,837**	**7,883**	**—**	**1**	**12,721**
Net revisions					
Price revisions	(389)	(3,981)	—	—	**(4,370)**
Performance and production revisions	46	1,378	—	—	**1,424**
Total net revisions	(343)	(2,603)	—	—	**(2,946)**
Extensions, discoveries and other additions					
Proved developed	198	69	—	—	**267**
Proved undeveloped	474	—	—	—	**474**
Total reserve additions	672	69	—	—	**741**
Production	(473)	(407)	—	—	**(880)**
Acquisition of reserves in place	223	2,131	—	—	**2,354**
Disposition of reserves in place	—	—	—	—	**—**
December 31, 2020	**4,916**	**7,073**	**—**	**1**	**11,990**

(1) The Fayetteville Shale E&P assets and associated reserves were divested in December 2018.

(2) Other includes properties outside of Appalachia and Fayetteville Shale.

(3) Performance and production revisions for the year ended December 31, 2019 include 109 Bcfe of proved undeveloped reserves reclassified to unproved due to changes in the drilling plan, in accordance with the SEC five-year rule.

The Company's December 31, 2020 proved reserves included 2,437 Bcfe of proved undeveloped reserves from 138 locations that had a positive present value on an undiscounted basis in compliance with proved reserve requirements, but do not have a positive present value when discounted at 10%. These properties had a negative present value of $207 million when discounted at 10%. The Company made a final investment decision and is committed to developing these reserves within the next five years from the date of initial booking.

The Company's December 31, 2019 proved reserves included 929 Bcfe of proved undeveloped reserves from 90 locations that had a positive present value on an undiscounted basis in compliance with proved reserve requirements, but that have a negative $50 million present value when discounted at 10%. The Company's December 31, 2018 proved reserves included 190

Bcfe of proved undeveloped reserves from 30 locations that had a positive present value on an undiscounted basis in compliance with proved reserve requirements, but that have a negative $24 million present value when discounted at 10%.

The Company has no reserves from synthetic gas, synthetic oil or nonrenewable natural resources intended to be upgraded into synthetic gas or oil. The Company used standard engineering and geoscience methods, or a combination of methodologies in determining estimates of material properties, including performance and test date analysis, offset statistical analogy of performance data, volumetric evaluation, including analysis of petrophysical parameters (including porosity, net pay, fluid saturations (i.e., water, oil and gas) and permeability) in combination with estimated reservoir parameters (including reservoir temperature and pressure, formation depth and formation volume factors), geological analysis, including structure and isopach maps and seismic analysis, including review of 2-D and 3-D data to ascertain faults, closure and other factors.

Standardized Measure of Discounted Future Net Cash Flows

The following standardized measures of discounted future net cash flows relating to proved natural gas, oil and NGL reserves as of December 31, 2020, 2019 and 2018 are calculated after income taxes, discounted using a 10% annual discount rate and do not purport to present the fair market value of the Company's proved gas, oil and NGL reserves:

(in millions)	2020	2019	2018
Future cash inflows	$ 17,997	$ 27,003	$ 34,523
Future production costs	(11,969)	(14,981)	(15,347)
Future development costs [(1)]	(1,924)	(3,246)	(4,095)
Future income tax expense	—	(476)	(2,079)
Future net cash flows	4,104	8,300	13,002
10% annual discount for estimated timing of cash flows	(2,257)	(4,600)	(7,003)
Standardized measure of discounted future net cash flows	$ 1,847	$ 3,700	$ 5,999

(1) Includes abandonment costs.

Under the standardized measure, future cash inflows were estimated by applying an average price from the first day of each month from the previous 12 months, adjusted for known contractual changes, to the estimated future production of year-end proved reserves. Prices used for the standardized measure above were as follows:

(in millions)	2020	2019	2018
Natural gas *(per MMBtu)*	$ 1.98	$ 2.58	$ 3.10
Oil *(per Bbl)*	39.57	55.69	65.56
NGLs *(per Bbl)*	10.27	11.58	17.64

Future cash inflows were reduced by estimated future production and development costs based on year-end costs to determine pre-tax cash inflows. Future income taxes were computed by applying the year-end statutory rate to the excess of pre-tax cash inflows over the Company's tax basis in the associated proved gas and oil properties after giving effect to permanent differences and tax credits.

Following is an analysis of changes in the standardized measure during 2020, 2019 and 2018:

(in millions)	2020	2019	2018
Standardized measure, beginning of year	$ 3,700	$ 5,999	$ 5,562
Sales and transfers of natural gas and oil produced, net of production costs	(478)	(923)	(1,564)
Net changes in prices and production costs	(2,720)	(3,510)	2,162
Extensions, discoveries, and other additions, net of future production and development costs	81	234	335
Acquisition of reserves in place	443	—	—
Sales of reserves in place	—	(2)	(2,022)
Revisions of previous quantity estimates	(987)	152	361
Net change in income taxes	35	491	(304)
Changes in estimated future development costs	1,241	621	(166)
Previously estimated development costs incurred during the year	624	704	536
Changes in production rates (timing) and other	(466)	(718)	521
Accretion of discount	374	652	578
Standardized measure, end of year	$ 1,847	$ 3,700	$ 5,999

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

We have performed an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer (Interim), of the effectiveness of our disclosure controls and procedures, as defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act. Our disclosure controls and procedures are the controls and other procedures that we have designed to ensure that we record, process, accumulate and communicate information to our management, including our Chief Executive Officer and Chief Financial Officer (Interim), to allow timely decisions regarding required disclosures and submission within the time periods specified in the SEC's rules and forms. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those determined to be effective can provide only a level of reasonable assurance with respect to financial statement preparation and presentation. Based on the evaluation, our management, including our Chief Executive Officer and Chief Financial Officer (Interim), concluded that our disclosure controls and procedures were effective as of December 31, 2020 at a reasonable assurance level.

During the quarter ended December 31, 2020, the Company completed its acquisition of Montage Resources. As part of the ongoing integration of the acquired business, we are in the process of incorporating the controls and related procedures of Montage. Other than incorporating Montage controls, there have been no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the quarter ended December 31, 2020, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting is included on page 72 of this Annual Report.

PricewaterhouseCoopers LLP's report on Southwestern Energy's internal control over financial reporting is included in its Report of Independent Registered Public Accounting Firm on page 72 of this Annual Report.

ITEM 9B. OTHER INFORMATION

On February 18, 2021, the Compensation Committee of the Board of Directors of Southwestern Energy Company granted, subject to the approval of the Board, long-term incentives under the Company's 2013 Incentive Plan, as amended (the "Plan"), to its principal executive officer and other named executive officers. On February 23, 2021, the Company's Board approved these grants.

The grants were comprised of three types of awards, the principal features of which are:

Restricted Stock Units. Each restricted stock unit that vests will entitle the holder to receive, payable in common stock or cash at the Compensation Committee's option, a value based on the closing stock price on the date of vesting. 33% of the restricted stock units vest on each of the first through the third anniversaries of the date of grant, provided the grantee is still an employee of the Company on the vesting date; however, all restricted stock units vest in the case of the grantee's retirement, death or disability or upon a change in control, all as defined in the Plan.

Performance Units. Each performance unit that vests will entitle the holder to receive a value payable in common stock or cash at the Compensation Committee's option, based on the Company's performance regarding specified metrics and the closing stock price on the date of vesting. The vesting date is the third anniversary of the date of grant, provided the grantee is still an employee of the Company on the vesting date; however, a pro rata portion of performance units vest in the case of the grantee's retirement, death or disability, as defined in the Plan. Upon a change in control, as defined in the Plan, the performance period is deemed to end upon the change of control, and each unit granted vests at the greater of target value and actual value based on the results of the performance measures. The determination of the value of each unit, 0-200%, is based on the achievement of threshold, target or maximum goals for the following metric over a three-year performance period, being the calendar years 2021-2023:

- Relative Total Shareholder Return – The difference between (a) the average of the closing prices for the Company's common stock on the last 20 trading days of 2023 plus all dividends paid on account of one share of the Company's common stock and (b) the average of the closing prices for the last 20 trading days of 2020, as compared to the same calculation for a specified group of the Company's peers.

Performance Cash Units. Each performance cash unit has a target value of $1.00. Each unit that vests will entitle the holder to receive a value, payable in cash, based on the Company's performance regarding specified metrics. The vesting date is the third anniversary of the date of grant, provided the grantee is still an employee of the Company on the vesting date; however, a pro rata portion of performance units vest in the case of the grantee's retirement, death or disability, as defined in the Plan. Upon a change in control, as defined in the Plan, the performance period is deemed to end upon the change of control, and each unit granted vests at the greater of the target value and actual value based on the results of the performance measures. The determination of the value of each unit, 0-200%, is based on the achievement of threshold, target or maximum goals on the following metrics over a three-year performance period, being the calendar years 2021-2023:

- 50% Return on Capital Employed – The sum of (A) net income (loss) adjusted for gain/loss on unsettled derivatives, gain/loss on early extinguishment of debt, gain/loss on sale of assets, impairments, restructuring and transaction-related charges, legal settlements, other one-time charges, adjustments due to discrete tax items, changes from the tax rate in effect at the beginning of the performance period, and the tax effect on adjustments ("Adjusted Net Income") and (B) interest expense less the product of (i) the interest expense and (ii) the Company's corporate tax rate in effect at the beginning of the performance period before the impact of valuation allowance divided by the sum of (C) the arithmetic average of the aggregate outstanding principal balance under debt instruments on December 31 of the year prior to the beginning of the performance period and December 31 of the final year of the performance period and (D) the arithmetic average of (i) stockholders' equity on December 31 of the year prior to the beginning of the performance period ("Stockholder's Equity") and (ii) the sum of (a) Stockholder's Equity and (b) Adjusted Net Income for each year during the performance period adjusted by changes reflected in the Consolidated Statement of Changes in Equity less Net Income (Loss).
- 50% Reinvestment Rate –total capital investments accrued for in a given year divided by cash flow from operating activities adjusted for changes in assets, liabilities, restructuring and other one-time charges.

William J. Way, President and Chief Executive Officer, was granted 618,330 Restricted Stock Units, 309,170 Performance Units, and 1,215,000 Performance Cash Units; Clay Carrell, Executive Vice President and Chief Operating Officer, was granted 293,130 Restricted Stock Units, 146,570 Performance Units, and 576,000 Performance Cash Units.

There was no additional information required to be disclosed in a current report on Form 8-K during the fourth quarter of the fiscal year ended December 31, 2020, that was not reported on such form.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The definitive proxy statement to holders of the Company's common stock in connection with the solicitation of proxies to be used in voting at the Annual Meeting of Stockholders to be held on or about May 18, 2021 (the "Proxy Statement"), is hereby incorporated by reference for the purpose of providing information about the Company's directors, and for discussion of its audit committee and its audit committee financial expert. Refer to the sections "Proposal No. 1: Election of Directors" and "Share Ownership of Management, Directors and Nominees" in the Proxy Statement for information concerning our directors. Refer to the section "Corporate Governance – Committees of the Board of Directors" in the 2021 Proxy Statement for discussion of its audit committee and its audit committee financial expert. Information concerning the Company's executive officers is presented in Part I of this Annual Report. The Company refers you to the section "Section 16(a) Beneficial Ownership Reporting Compliance" in the Proxy Statement for information relating to compliance with Section 16(a) of the Exchange Act.

Code of Business Ethics and Conduct for Directors and Employees

The Company has adopted Business Conduct Guidelines that apply to its Chief Executive Officer, Chief Financial Officer (Interim) and Controller as well as other officers and employees. We have posted a copy of our Business Conduct Guidelines on the "Corporate Governance" section of our website at www.swn.com, and it is available free of charge in print to any stockholder who requests it. Requests for copies should be addressed to the Secretary at 10000 Energy Drive, Spring, Texas 77389. Any amendments to, or waivers from, our code of ethics that apply to our executive officers and directors will be posted on the "Corporate Governance" section of our website. Note that the information on the Company's website is not incorporated by reference into this filing.

ITEM 11. EXECUTIVE COMPENSATION

Information required by Item 11 of Part III will be included in our Proxy Statement relating to our 2021 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before May 18, 2021, and is incorporated herein by reference.*

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required by Item 12 of Part III will be included in our Proxy Statement relating to our 2021 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before May 18, 2021, and is incorporated herein by reference.*

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

Information required by Item 13 of Part III will be included in our Proxy Statement relating to our 2021 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before May 18, 2021, and is incorporated herein by reference.*

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information required by Item 14 of Part III will be included in our Proxy Statement relating to our 2021 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before May 18, 2021, and is incorporated herein by reference.*

* Except for information or data specifically incorporated by reference under Items 10 through 14, all other information in our 2021 Proxy Statement is not deemed to be a part of this Annual Report or deemed to be filed with the Commission as part of this report.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) (1) The consolidated financial statements of Southwestern Energy Company and its subsidiaries and the report of independent registered public accounting firm are included in Item 8 of this Annual Report.

(2) The consolidated financial statement schedules have been omitted because they are not required under the related instructions, or are not applicable.

(3) The exhibits listed on the accompanying Exhibit Index are filed as part of, or incorporated by reference into, this Annual Report.

ITEM 16. SUMMARY

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused the report to be signed on its behalf by the undersigned, thereunto duly authorized.

	SOUTHWESTERN ENERGY COMPANY
Dated: March 1, 2021	By: /s/ MICHAEL E. HANCOCK
	Michael Hancock
	Vice President and Chief Financial Officer (Interim)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed, as of March 1, 2021, on behalf of the Registrant below by the following officers and by a majority of the directors.

/s/ WILLIAM J. WAY William J. Way	Director, President and Chief Executive Officer (Principal executive officer)
/s/ MICHAEL E. HANCOCK Michael Hancock	Vice President and Chief Financial Officer (Interim) (Principal financial officer)
/s/ COLIN P. O'BEIRNE Colin P. O'Beirne	Vice President, Controller (Principal accounting officer)
/s/ JOHN D. GASS John D. Gass	Director
/s/ CATHERINE KEHR Catherine Kehr	Director
/s/ GREG D. KERLEY Greg D. Kerley	Director
/s/ JON A. MARSHALL Jon A. Marshall	Director
/s/ PATRICK M. PREVOST Patrick M. Prevost	Director
/s/ ANNE TAYLOR Anne Taylor	Director
/s/ DENIS J. WALSH III Denis J. Walsh III	Director
/s/ SYLVESTER P. JOHNSON IV Sylvester P. Johnson IV	Director

EXHIBIT INDEX

Exhibit Number	Description
2.1	Agreement and Plan of Merger, dated as of August 12, 2020, by and between Southwestern Energy Company and Montage Resources Corporation (Incorporated by reference to Exhibit 2.1 to the Registrant's Current Report on Form 8-K/A filed on August 12, 2020)
3.1	Amended and Restated Certificate of Incorporation of Southwestern Energy Company. (Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed May 24, 2010)
3.2	Amended and Restated Bylaws of Southwestern Energy Company, as amended on April 28, 2020. (Incorporated by reference to Exhibit 3.2 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2020)
4.1	Description of the Company's Securities Registered under Section 12 of the Securities Exchange Act of 1934 (Incorporated by reference to Exhibit 4.1 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2019)
4.2	Form of Common Stock Certificate. (Incorporated by reference to Exhibit 4.4 to the Registrant's Current Report on Form 8-K/A filed August 3, 2006)
4.3	Policy on Confidential Voting of Southwestern Energy Company. (Incorporated by reference to the Appendix of the Registrant's Definitive Proxy Statement (Commission File No. 1-08246) for the 2006 Annual Meeting of Stockholders)
4.4	Indenture by and among Southwestern Energy Company, SEECO, Inc., Southwestern Energy Production Company, Southwestern Energy Services Company and The Bank of New York Trust Company, N.A., as trustee, dated as of March 5, 2012. (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed March 6, 2012)
4.5	First Supplemental Indenture, dated as of November 29, 2017 between Southwestern Energy Company and The Bank of New York Mellon Trust Company, N.A., as trustee (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed December 1, 2017)
4.6	Second Supplemental Indenture, dated as of April 26, 2018 between Southwestern Energy Company, the guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on April 26, 2018)
4.7	Third Supplemental Indenture, dated as of September 17, 2018 between Southwestern Energy Company and The Bank of New York Mellon Trust Company, N.A., as trustee (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on September 18, 2018)
4.8*	Fourth Supplemental Indenture, dated as of December 10, 2020 between Southwestern Energy Company and The Bank of New York Mellon Trust Company, N.A., as trustee
4.9	Form of 4.10% Notes due 2022. (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on March 5, 2012)
4.10	Indenture, dated as of January 23, 2015 between Southwestern Energy Company and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on January 23, 2015)
4.11	First Supplemental Indenture, dated as of January 23, 2015 between Southwestern Energy Company and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on January 23, 2015)
4.12	Second Supplemental Indenture, dated as of September 25, 2017 between Southwestern Energy Company and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.5 to the Registrant's Current Report on Form 8-K filed on September 25, 2017)
4.13	Third Supplemental Indenture, dated as of November 29, 2017 between Southwestern Energy Company and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on December 1, 2017)
4.14	Fourth Supplemental Indenture, dated as of April 26, 2018 between Southwestern Energy Company, the guarantors named therein and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on April 26, 2018)
4.15*	Fifth Supplemental Indenture, dated as of December 3, 2018 between Southwestern Energy Company, the guarantors named therein and U.S. Bank National Association, as trustee
4.16*	Sixth Supplemental Indenture, dated as of December 10, 2020 between Southwestern Energy Company, the guarantors named therein and U.S. Bank National Association, as trustee
4.17	Form of 4.95% Notes due 2025. (Incorporated by reference to Exhibit 4.5 to the Registrant's Current Report on Form 8-K filed on January 23, 2015)

4.18	Indenture, dated as of September 25, 2017 between Southwestern Energy Company and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on September 25, 2017)
4.19	First Supplemental Indenture, dated as of September 25, 2017 between Southwestern Energy Company and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on September 25, 2017)
4.20	Second Supplemental Indenture, dated as of April 26, 2018 between Southwestern Energy Company, the guarantors named therein and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.3 to the Registrant's Current Report on Form 8-K filed on April 26, 2018)
4.21*	Third Supplemental Indenture, dated as of December 3, 2018 between Southwestern Energy Company, the guarantors named therein and U.S. Bank National Association, as trustee
4.22	Fourth Supplemental Indenture, dated as of August 27, 2020 between Southwestern Energy Company, the guarantors named therein and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on August 27, 2020)
4.23*	Fifth Supplemental Indenture, dated as of December 10, 2020 between Southwestern Energy Company, the guarantors named therein and U.S. Bank National Association, as trustee
4.24	Form of 7.50% Notes due 2026. (Incorporated by reference to Exhibit 4.3 to the Registrant's Current Report on Form 8-K filed on September 25, 2017)
4.25	Form of 7.75% Notes due 2027. (Incorporated by reference to Exhibit 4.4 to the Registrant's Current Report on Form 8-K filed on September 25, 2017)
4.26	Form of 8.375% Notes due 2028. (Incorporated by reference to Exhibit 4.3 to the Registrant's Current Report on Form 8-K filed on August 27, 2020)
10.1	Form of Second Amended and Restated Indemnity Agreement between Southwestern Energy Company and each Executive Officer and Director of the Registrant. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K/A filed August 3, 2006)
10.2	Form of Executive Severance Agreement between Southwestern Energy Company and each of the Executive Officers of Southwestern Energy Company, effective February 17, 1999. (Incorporated by reference to Exhibit 10.12 of the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 1998)
10.3	Form of Amendment to Executive Severance Agreement between Southwestern Energy Company and each of the Executive Officers of Southwestern Energy Company prior to 2011. (Incorporated by reference to Exhibit 10.3 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2008)
10.4	Form of Executive Severance Agreement between Southwestern Energy Company and Executive Officers Post 2011. (Incorporated by reference to Exhibit 10.4 to the Registrant's Annual Report on Form 10-K (Commission File No.1-08426) for the year ended December 31, 2011)
10.5	Southwestern Energy Company Supplemental Retirement Plan as amended. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on February 19, 2008)
10.6	Southwestern Energy Company Non-Qualified Retirement Plan as amended. (Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed on February 19, 2008)
10.7	Amendment One to the Southwestern Energy Company Non-Qualified Retirement Plan (Incorporated by reference to Exhibit 10.9 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2009)
10.8	Southwestern Energy Company 2013 Incentive Plan. (Incorporated by reference to Annex A of the Registrant's Proxy Statement filed April 8, 2013)
10.9	First Amendment to Southwestern Energy Company 2013 Incentive Plan. (Incorporated by reference to Exhibit 4.1 of the Registrant's Current Report on Form 8-K filed on May 20, 2016)
10.10	Second Amendment to Southwestern Energy Company 2013 Incentive Plan. (Incorporated by reference to Exhibit 4.1 of the Registrant's Current Report on Form 8-K filed on May 30, 2017)
10.11	Third Amendment to Southwestern Energy Company 2013 Incentive Plan. (Incorporated by reference to Exhibit 4.1 of the Registrant's Current Report on Form 8-K filed on May 22, 2019)
10.12	Southwestern Energy Company 2013 Incentive Plan Form of Performance Unit Award Agreement, for awards granted prior to February 25, 2020. (Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed on March 8, 2018)
10.13	Southwestern Energy Company 2013 Incentive Plan Form of Performance Unit Award Agreement, for awards granted on or after February 25, 2020 and prior to February 23, 2021. (Incorporated by reference to Exhibit 10.13 to the Registrant's Annual Report on Form 10-K (Commission No. 001-08246) for the year ended December 31, 2019)

10.14*	Southwestern Energy Company 2013 Incentive Plan Form of Performance Unit Award Agreement, for awards granted on or after February 23, 2021.
10.15	Southwestern Energy Company 2013 Incentive Plan Guidelines for Annual Incentive Awards. (Incorporated by reference to Exhibit 10.03 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)
10.16	Southwestern Energy Company 2013 Incentive Plan Form of Incentive Stock Option Award Agreement. (Incorporated by reference to Exhibit 10.04 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)
10.17	Southwestern Energy Company 2013 Incentive Plan Form of Non-Qualified Stock Option Award Agreement. (Incorporated by reference to Exhibit 10.05 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)
10.18	Southwestern Energy Company 2013 Incentive Plan Form of Non-Qualified Stock Option Award Agreement for Directors. (Incorporated by reference to Exhibit 10.06 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)
10.19	Southwestern Energy Company 2013 Incentive Plan Form of Restricted Stock Award Agreement. (Incorporated by reference to Exhibit 10.07 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)
10.20	Southwestern Energy Company 2013 Incentive Plan Form of Restricted Stock Award Agreement for Directors, as amended on May 23, 2017. (Incorporated by reference to Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2017)
10.21	Southwestern Energy Company 2013 Incentive Plan Form of Restricted Stock Unit Award Agreement. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on March 8, 2018)
10.22	Southwestern Energy Company 2013 Incentive Plan Form of Restricted Stock Unit Award Agreement for Officers, for awards granted prior to February 23, 2021. (Incorporated by reference to Exhibit 10.21 to the Registrant's Annual Report on Form 10-K (Commission No. 001-08246) for the year ended December 31, 2019)
10.23*	Southwestern Energy Company 2013 Incentive Plan Form of Restricted Stock Unit Award Agreement for Officers, for awards granted on or after February 23, 2021
10.24	Southwestern Energy Company 2013 Incentive Plan Form of Restricted Stock Unit Award Agreement for Directors, for awards granted prior to July 1, 2019. (Incorporated by reference to Exhibit 10.10 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)
10.25	Southwestern Energy Company 2013 Incentive Plan Form of Restricted Stock Unit Award Agreement for Directors, for awards granted on or after July 1, 2019. (Incorporated by reference to Exhibit 10.4 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2019)
10.26*	Southwestern Energy Company 2013 Incentive Plan Form of Performance Cash Unit Award Agreement
10.27	Southwestern Energy Company Non-Employee Director Deferred Compensation Plan. (Incorporated by reference to Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2019)
10.28	Form of Deferral Agreement under the Non-Employee Director Deferred Compensation Plan. (Incorporated by reference to Exhibit 10.3 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2019)
10.29	Form of Incentive Stock Option for awards granted on or after December 8, 2005. (Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed on December 13, 2005)
10.30	Form of Non-Qualified Stock Option Agreement for awards granted on or after December 8, 2011. (Incorporated by reference to Exhibit 10.20 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08426) for the year ended December 31, 2011)
10.31	Guaranty by and between Southwestern Energy Company and Texas Gas Transmission, LLC, dated as of October 27, 2008. (Incorporated by reference to Exhibit 10.3 to the Registrant's Quarterly Report on Form 10-Q (Commission File No. 1-08246) for the period ended September 30, 2008)
10.32	Guaranty by and between Southwestern Energy Company and Fayetteville Express Pipeline, LLC dated September 30, 2008 (Incorporated by reference to Exhibit 10.22 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2009)
10.33	Credit Agreement, dated as of April 26, 2018 among Southwestern Energy Company, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders from time to time party thereto. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on April 26, 2018)
10.34	Amendment No. 1 to Credit Agreement, dated as of April 26, 2018 among Southwestern Energy Company, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto. (Incorporated by reference to Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q filed on October 25, 2018)
10.35	Amendment No. 2 to Credit Agreement, dated as of April 26, 2018 among Southwestern Energy Company, JPMorgan Chase Bank N.A., as Administrative Agent, and each lender from time to time party thereto. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on October 9, 2019)

10.36	Amendment No. 3 to Credit Agreement, dated as of April 26, 2018 among Southwestern Energy Company, JPMorgan Chase Bank N.A., as Administrative Agent, and each lender from time to time party thereto (Incorporated by reference to Exhibit 10.42 to the Registrant's Annual Report on Form 10-K (Commission No. 001-08246) for the year ended December 31, 2019)
10.37	Amendment No. 4 to Credit Agreement, dated as of April 26, 2018 among Southwestern Energy Company, JPMorgan Chase Bank N.A., as Administrative Agent, and each lender from time to time party thereto (Incorporated by reference to Exhibit 10.43 to the Registrant's Annual Report on Form 10-K (Commission No. 001-08246) for the year ended December 31, 2019)
10.38*	Amendment No. 5 to Credit Agreement, dated as of April 26, 2018 among Southwestern Energy Company, JPMorgan Chase Bank N.A., as Administrative Agent, and each lender from time to time party thereto
10.39	Amendment No. 6 to Credit Agreement, dated as of July 31, 2020, among Southwestern Energy Company, the lenders party thereto and JP Morgan Chase Bank, N.A., as administrative agent for the lenders (Incorporated by reference to Exhibit 10.2 to the Registrant's Quarterly Report on on Form 10-Q filed on October 29, 2020)
10.40	Amendment No. 7 to Credit Agreement, dated as of August 18, 2020, among Southwestern Energy Company, the lenders party thereto and JP Morgan Chase Bank, N.A., as administrative agent for the lenders (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed August 20, 2020)
10.41	Amendment No. 8 to Credit Agreement, dated as of October 8, 2020, among Southwestern Energy Company, the lenders party thereto and JP Morgan Chase Bank, N.A., as administrative agent for the lenders (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed October 8, 2020)
10.42*	Amendment No. 9 to Credit Agreement, dated as of December 11, 2020 among Southwestern Energy Company, JPMorgan Chase Bank N.A., as Administrative Agent, and each lender from time to time party thereto
10.43	Support Agreement, dated as of August 12, 2020, by and among certain stockholders affiliated with EnCap Investments L.P. and Southwestern Energy Company (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on August 12, 2020)
10.44	Retirement and Consulting Agreement dated June 4, 2020 by and between Southwestern Energy Company and John C. Ale. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Commission File No. 1-08246) filed June 4, 2020)
21.1*	List of Subsidiaries
23.1*	Consent of PricewaterhouseCoopers LLP
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of CEO filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification of CFO filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certification of CEO furnished pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2*	Certification of CFO furnished pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
95.1*	Mine Safety Disclosure
99.1*	Reserve Audit Report of Netherland, Sewell & Associates, Inc., dated February 9, 2021
101.1*	Interactive Data Files Pursuant to Rule 405 of Regulation S-T, formatted in Inline XBRL: (i) Consolidated Statements of Operations for the three years ended December 31, 2020, (ii) Consolidated Statements of Comprehensive Income for the three years ended December 31, 2020, (iii) Consolidated Balance Sheets as of December 31, 2020 and 2019, (iv) Consolidated Statements of Cash Flows for the three years ended December 31, 2020, (v) Consolidated Statements of Changes in Equity for the three years ended December 31, 2020 and (vi) Notes to Consolidated Financial Statements
104.1*	The cover page from the Company's Annual Report on Form 10-K for the year ended December 31, 2020, formatted in Inline XBRL (included in Exhibit 101)

* Filed herewith