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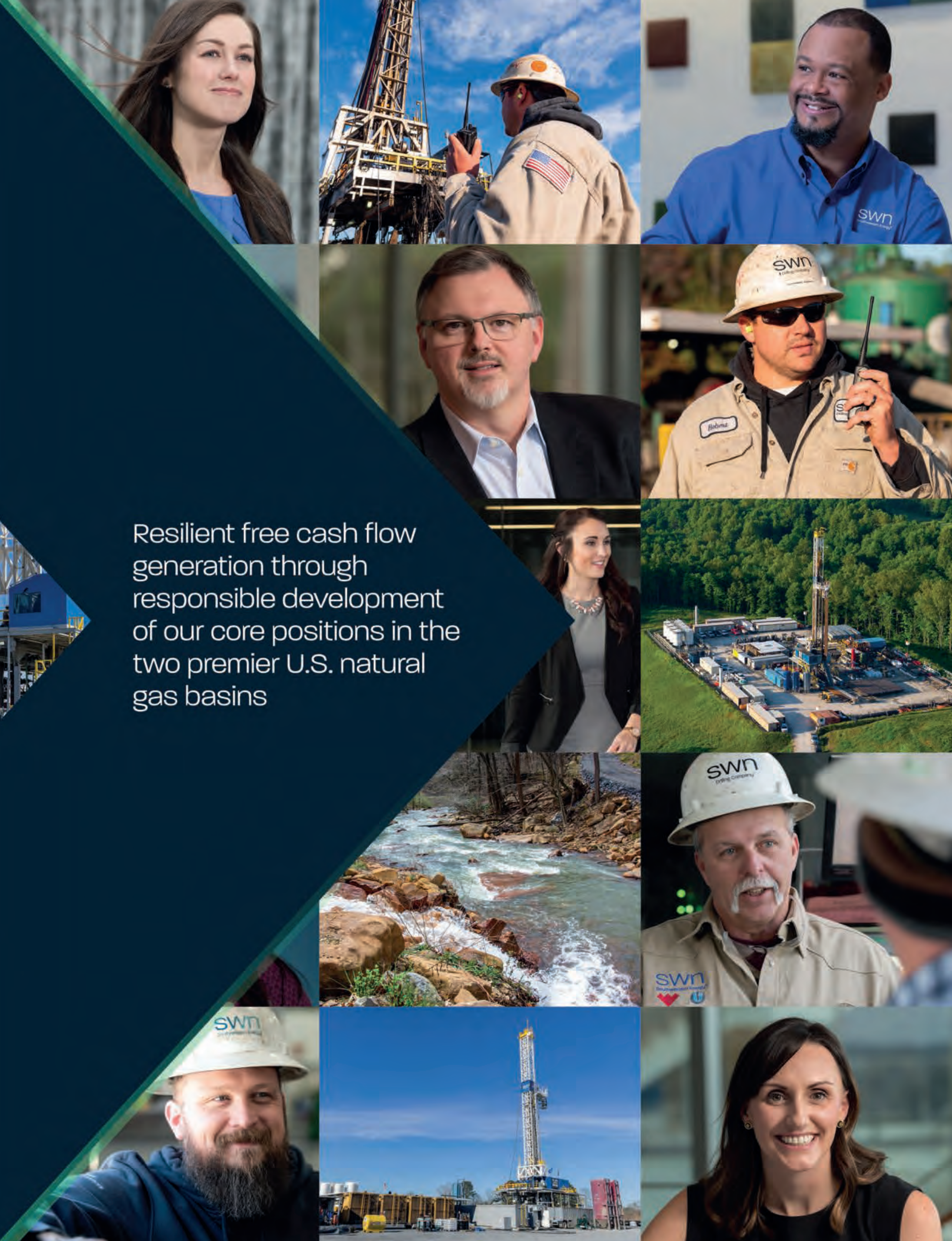
Natural Gas *Forward*

swn
Southwestern Energy®

2021 ANNUAL REPORT



Resilient free cash flow generation through responsible development of our core positions in the two premier U.S. natural gas basins

Dear Fellow Shareholders

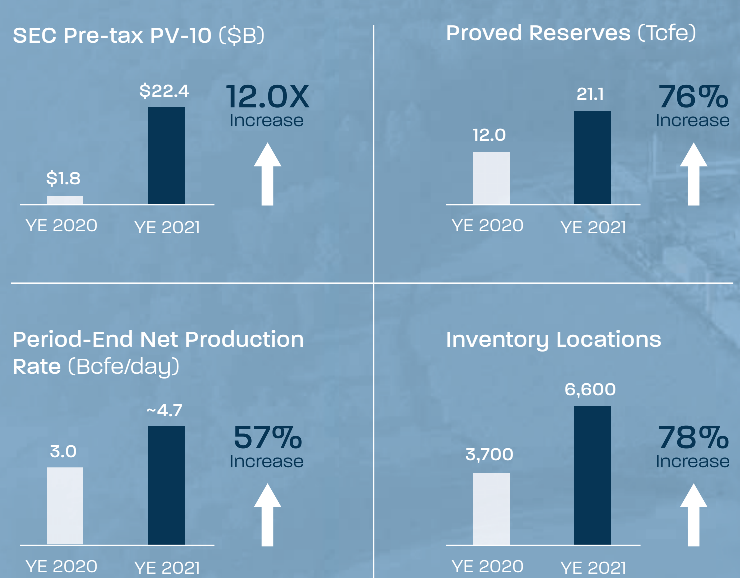
As events in Ukraine have unfolded, I have experienced deep admiration and hope at seeing the unrelenting resolve of the Ukrainian people fighting for their freedom along with shock and dismay at witnessing unprovoked violence and loss of life. We at Southwestern Energy join others in calling for our shared sense of humanity to prevail over brute aggression.

As world leaders continue to work to end these hostilities, we all are seeing the impact of these events on global markets, underscoring the unmistakable importance of global energy security. Southwestern Energy is well positioned to help secure both domestic and global energy needs and to capitalize on the accelerating role of natural gas as a foundational energy source for a low carbon future.

RESILIENT FREE CASH FLOW GENERATION

We are certainly pleased with the free cash flow that we generated in 2021, which is expected to increase in 2022. Our strategic intent is to generate resilient free cash flow from responsibly produced natural gas. Within our demonstrated strategic execution capability, we maintain a comprehensive focus on the Company's business and the global role of natural gas, while anticipating and mitigating risks to deliver on our strategic intent.

Complementary Assets in Premier US Natural Gas Basins



Bill Way
President and Chief Executive Officer

Production presented pro forma for GEP Haynesville acquisition. SWN YE 2021 reported production was approximately 4.2 Bcfe per day. Pre-tax PV-10 is a non-GAAP measure. Before the impact of taxes, PV-10 was $1.8 billion and $18.7 billion for 2020 and 2021, respectively.

These considerations drove the disciplined execution of two strategic transactions last year to transform the Company into the second largest domestic producer of natural gas and the largest domestic dual-basin gas producer. Our new Haynesville assets complement our premium Appalachia assets, resulting in a deepened and upgraded inventory of over 6,600 economic drilling locations, including more than 15 years of core inventory. Our timely strategic move increased access to growing demand centers, with 65 percent of the Company's natural gas production having access to Gulf Coast and LNG premium markets. The enhanced magnitude and durability of the free cash flow generation capability of our business is reflected in our record year-end reported reserves, with a debt-adjusted value approximately two times the Company's current market value.

In addition to improved free cash flow generation, the tangible benefits of the Company's newfound scale also include an improved enterprise risk profile with expanded basin, market and commodity optionality. We have

accelerated deleveraging, lowered our cost of capital, and increased our liquidity and capital market access, all supporting the Company's strategic intent of generating resilient free cash flow.

Our transformed Company has not gone unnoticed as S&P recognized our improved enterprise risk profile by upgrading us in January 2022 for the second time in the last six months. We are now one-notch away from returning to investment grade, which remains a key strategic priority.

While we believe it is prudent to prioritize using free cash flow to reduce debt in the near-term, we recognize that any sustainable shareholder value proposition must ultimately incorporate the return of capital. As we approach and have a clear line-of-sight to achieving our leverage ratio and total debt target ranges, we expect to be in a position to initiate a return of capital program that reflects our confidence in the resilient free cash flow generation capability of our asset base.

NATURAL GAS, *FORWARD.*

We believe that natural gas is foundational to a low carbon future, offering a cleaner and more reliable energy source that has a vital role to play in helping achieve the global goal of reducing greenhouse gas emissions. Indeed, governments such as the European Union as well as major investment funds have increasingly acknowledged the role natural gas will play as part of the energy transition.

At SWN, we are focused on the responsible development of our Tier 1 assets, which we believe is key to sustainable value creation. This includes minimizing the impact our operations have on the communities where we work and live and reducing greenhouse gas emissions, including methane. In 2021, we reduced the Company's methane intensity by 18%, including for assets acquired in 2020, surpassing the goal we set and incorporated into our compensation program. We also announced and began implementing Company-wide well certification and continuous monitoring of our production. This responsibly sourced gas ("RSG") will provide customers and investors with measured, credible and verifiable environmental performance data. For the sixth straight year, we again returned more fresh water to the environment than we used in operations.

Following the significant growth of the Company, we are integrating our leading HSE and ESG programs across our entire portfolio. This includes analyzing the key sources of GHG emissions in our operations including our newly-acquired Haynesville assets. As we complete the emissions reduction analysis of our combined assets, we commit and look forward to disclosing a longer-term GHG reduction goal in connection with our ninth annual corporate responsibility report later this year.

Over the past few years, we have significantly improved the Company's strategic positioning and operational performance while demonstrating financial resiliency. We are particularly proud of the transformational steps taken in 2021. We remain focused on the future as we seek to deliver growing and sustainable value for our shareholders from our core positions in the two premier natural gas basins in the United States in 2022 and beyond.

I am profoundly grateful to the people of SWN and the grit they have shown over the past several years. Without them, SWN would not be where it is today. On behalf of SWN and its people, we thank you for your continued confidence and support.

Sincerely,

BILL WAY
President and Chief Executive Officer
Southwestern Energy

Executive Officers

William J. Way (10)
President and Chief Executive Officer

Clayton A. Carrell (4)
Executive Vice President and Chief Operating Officer

Carl F. Giesler, Jr. (*)
Executive Vice President and Chief Financial Officer

Carina Gillenwater (3)
Vice President – Human Resources

R. Jason Kurtz (24)
Vice President – Marketing and Transportation

Christopher W. Lacy (7)
Vice President, General Counsel and Corporate Secretary

Directors

From left to right: **John D. Gass (9)**, *Retired–Chevron Corporation;* **Anne Taylor (3)**, *Retired–Deloitte;* **Jon A. Marshall (5)**, *Retired–Transocean Ltd.;* **Denis J. Walsh III (2)**, *Retired–BlackRock Inc.;* **Catherine A. Kehr (10)**, *Retired–The Capital Group Companies;* **Greg D. Kerley (11)**, *Retired–CFO Southwestern Energy Company;* **Patrick M. Prevost (4)**, *Retired–Cabot Corporation;* **William J. Way (6)**, *President and Chief Executive Officer;* **S.P. "Chip" Johnson IV (1)**, *Retired–Callon Petroleum*

Corporate Officers

William J. Way (10)
President and Chief Executive Officer

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Executive Vice President and Chief Operating Officer

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Vice President – Marketing and Transportation

Christopher W. Lacy (7)
Vice President, General Counsel and Corporate Secretary

Michael E. Hancock (12)
Vice President – Finance and Treasurer

Colin P. O'Beirne (11)
Vice President and Controller

Arlington W. Price (*)
Vice President - Business Information Systems

Operating Subsidiary Officers

Derek W. Cutright (13)
Senior Vice President – Southwest Appalachia Division

William Q. Dyson (4)
Senior Vice President – Operations Services

Andrew T. Huggins (14)
Senior Vice President – Haynesville Division

John P. Kelly Jr. (4)
Senior Vice President – Northeast Appalachia Division

For Directors, *years served on the Board of Directors are shown on this page in parentheses, and an asterisk (*) indicates less than one year of service.*
For Executive Officers, *years with the Company are shown on this page in parentheses, and an asterisk (*) indicates less than one year of service.*

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, 2021**
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 and non-voting common equity held by non-affiliates of the registrant was $3,815,156,281 based on the New York Stock Exchange – Composite Transactions closing price on June 30, 2021 of $5.67. For purposes of this calculation, the registrant has assumed that its directors and executive officers are affiliates.

As of February 25, 2022, the number of outstanding shares of the registrant's Common Stock, par value $0.01, was 1,114,319,444.

Document Incorporated by Reference

Portions of the registrant's definitive proxy statement for the 2022 annual meeting of stockholders, to be filed no later than 120 days after the end of the fiscal year to which this Annual Report on Form 10-K relates, 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, 2021

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CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K (“Annual Report”) includes certain statements that 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, other than statements of historical fact or present financial information, 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. These forward-looking statements are based on management’s current beliefs, based on currently available information, as to the outcome and timing of future events. 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 pandemic or other world health event;
- 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;
- geopolitical and business conditions in key regions of the world;
- difficulties in appropriately allocating capital and resources among our strategic opportunities;
- the timing and extent of our success in discovering, developing, producing, replacing and estimating reserves;
- our ability to maintain leases that may expire if production is not established or profitably maintained;
- our ability to meet natural gas delivery commitments and to utilize or monetize our firm transportation commitments;
- our ability to realize the expected benefits from acquisitions, including the Mergers (defined below);
- costs in connection with the Mergers and the transactions contemplated thereby;
- integration of operations and results subsequent to the Mergers;
- risks related to the Mergers, including potential litigation relating to the Mergers, and the effect of the consummation of the Mergers on business relationships, operating results, employees, stakeholders and business generally of the parties;
- 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;
- our hedging strategy and results;
- our ability to obtain debt or equity financing on satisfactory terms; 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.

Reserve engineering is a process of estimating underground accumulations of natural gas, oil and NGLs that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and our development program. Accordingly, reserve estimates may differ significantly from the quantities of natural gas, oil and NGLs that are ultimately recovered.

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

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.

"<u>Acquisition of properties</u>" 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.

"<u>Available reserves</u>" 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.

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

"<u>Bbl</u>" One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

"<u>Bcf</u>" One billion cubic feet of natural gas.

"<u>Bcfe</u>" 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.

"<u>Btu</u>" 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.

"<u>Deterministic estimate</u>" 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.

"<u>Developed oil and gas reserves</u>" 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.

"ESG" Environmental, Societal and Governance matters.

"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.

"Free cash flow" A supplemental non-GAAP financial measure. As used by the Company, free cash flow is defined as net cash provided by operating activities, adjusted for (i) changes in assets and liabilities and (ii) cash costs associated with mergers and restructuring, less capital investments.

"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.

"HSE" Health, Safety and Environmental matters.

"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.

"LNG" Liquefied Natural Gas.

"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.

"NYSE" The New York Stock Exchange, the stock exchange on which our common stock trades.

"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" or "PDP" 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.

"Standardized measure" Discounted future net cash flows estimated by applying year-end prices to the estimated future production of year-end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period-end costs to determine pre-tax cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the natural gas and oil properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate.

"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.

SUMMARY RISK FACTORS

Risks Related to Our Business

- Natural gas, oil and NGL prices and basis differentials greatly affect our revenues and thus profits, liquidity, growth, ability to repay our debt and the value of our assets.
- Significant capital investment is required to develop and replace our reserves and conduct our business.
- If we are not able to develop and replace reserves, our production levels and thus our revenues and profits may decline.
- Our business depends on access to natural gas, oil and NGL gathering, processing and transportation systems and facilities. Changes to access and cost of these systems and facilities could adversely impact our business and financial condition. Our commitments to assure availability of transportation could lead to substantial payments for capacity we do not use if production falls below projected levels.
- 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.
- 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.
- 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.
- Natural gas and oil drilling and producing and transportation operations are complex and can be hazardous and may expose us to liabilities. Incidents related to HSE performance and our asset and operating integrity could adversely impact our business and financial condition.
- 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.

- 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.
- A large portion of our producing properties remain concentrated in the Appalachian basin, making us vulnerable to risks associated with operating in limited geographic areas.
- Many of our business operations depend on activities performed by third parties. Changes to availability, costs and performance of personnel, products and services provided by third parties could adversely impact our business and financial condition.
- Changes to the ability of our customers to receive our products or meet their financial, performance and other obligations to us could adversely impact our business and financial condition.
- 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.
- We may be unable to dispose of assets on attractive terms, and may be required to retain liabilities for certain matters.
- Changes to applicable U.S. tax laws and regulations could affect our business and future profitability.
- Our ability to use our net operating loss carryforwards and certain other tax attributes will be limited.
- We may experience adverse or unforeseen tax consequences due to further developments affecting our deferred tax assets which could significantly affect our results of operations.
- A cyber incident could result in information theft, data corruption, operational disruption and/or financial loss.
- Terrorist activities could materially and adversely affect our business and results of operations.
- The physical impacts of adverse weather may have a negative impact on our business and results of operations.
- Negative public perception regarding us and/or our industry and increasing attention to ESG matters could have an adverse effect on our business, financial condition and results of operations and damage our reputation.
- Judicial decisions can affect our rights and obligations.
- Common stockholders will be diluted if additional shares are issued.
- 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.
- Loss of our key executive officers or other personnel, or an inability to attract and retain such officers and personnel, could negatively affect our business.
- The COVID-19 pandemic has negatively affected, and may in the future negatively affect, our business, operating results and financial condition.

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.
- Our current and future levels of indebtedness may adversely affect our results and limit our growth.
- Any significant reduction in the borrowing base under our 2018 credit facility may negatively impact our ability to fund our operations, and we may not have sufficient funds to repay borrowings under our 2018 credit facility if required as a result of a borrowing base redetermination.
- 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.
- The elimination of LIBOR may adversely affect the cost of our borrowings.

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.
- 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.

Risks Related to Financial Markets and Uncertainties

- The trading price and volume of our common stock may be volatile, and you could lose a significant portion of your investment.

- Market views of our industry generally can affect our stock price, liquidity and ability to obtain financing.
- Volatility in the financial markets or in global economic factors could adversely impact our business and financial condition.

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

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

Risks Related to the Indigo Merger and the GEPH Merger

- We may not achieve the anticipated benefits of the Indigo Merger and the GEPH Merger (both defined below), and the Indigo Merger and the GEPH Merger may disrupt our current plans or operations.

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, associated natural gas liquids ("NGLs") and oil 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."

Our Business Strategy

We aim to deliver economic returns and optimize our ability to generate free cash flow through responsible natural gas development. As we develop our core positions in the Appalachian and Haynesville natural gas basins in the U.S., we will concentrate on:

- ***Creating Value.*** We seek to create value for our stakeholders by allocating capital that is focused on earning economic returns; delivering free cash flow; upgrading the quality, depth and capital efficiency of our drilling inventory; and converting resources to proved reserves.
- ***Financial Strength.*** We intend to protect our financial strength by lowering our leverage ratio and total debt; extending the weighted average years to maturity of our debt; lowering our cost of debt; deploying hedges to protect against downward price movement; covering our costs and meeting other financial commitments; and maintaining a strong liquidity position.
- ***Focus on Execution.*** We are focused on operating effectively and efficiently with HSE and ESG as core values; building on our data analytics, operating execution, strategic sourcing, vertical integration and large-scale asset development expertise; further enhancing well performance, optimizing well costs and reducing base production declines; growing margins and securing flow assurance through commercial and marketing arrangements.
- ***Capturing the Tangible Benefits of Scale.*** We strive to create a competitive advantage through strategic transactions that we believe will enhance enterprise returns and deliver financial synergies and operational economies. We believe these transactions lower the risk of our business, expand our opportunity set, increase business optionality and build upon our demonstrated record of asset integration.

Our Company's formula, "The Right People doing the Right Things, wisely investing the cash flow from our underlying Assets will create Value+," guides how we conduct our business:

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

We strive to attract and retain strong talent, to work safely, to act ethically with steadfast vigilance for the environment and the communities in which we live and operate, and to apply technical skills to grow and develop our asset base. We believe these practices will enhance long-term value for our shareholders.

During 2021 we executed on this strategy by:

- Integrating the natural gas and liquids assets acquired in our November 2020 merger with Montage Resources Corporation (the "Montage Merger"), which expanded our operations in Appalachia;
- Expanding our operations into the Haynesville with the Indigo Merger and GEPH Merger. This expansion lowered our enterprise business risk, deepened our economic drilling inventory, expanded our business opportunity set and optionality and enabled immediate cost structure savings;
- Lowering our costs through drilling, completions, operational and administrative efficiencies and optimizing gathering and transportation;
- Focusing on delivering operational results, such as improved well productivity and economics from enhanced completion techniques, optimization of surface equipment and managing reservoir drawdown as well as base production declines;
- Announced and began implementing responsibly sourced gas certification and continuous emissions monitoring of Appalachia production;
- Maintaining a multi-year hedging program to protect cash flow from adverse price changes;
- Lowering our cost of debt, expanding our liquidity, extending the weighted average years to maturity of our debt and improving our credit ratings through financings to fund the cash consideration for the Indigo Merger and GEPH Merger (as defined below) and associated liability management; and
- Publishing our 8th Annual Corporate Responsibility report (available at www.swn.com).

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 and associated NGL and oil 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 and production of natural gas as well as associated NGLs and oil in our core positions in the Appalachia and Haynesville natural gas basins in the U.S. We are currently focused on the development of unconventional natural gas reservoirs located in Pennsylvania, West Virginia, Ohio and Louisiana. Our operations in Pennsylvania, West Virginia and Ohio (herein referred to as "Appalachia") are primarily focused on the Marcellus Shale, the Utica and the Upper Devonian unconventional natural gas and liquids reservoirs. Our operations in Louisiana (herein referred to as "Haynesville") are primarily focused on the Haynesville and Bossier natural gas reservoirs.

- Our E&P segment recorded operating income of $2,583 million in 2021, compared to an operating loss of $2,864 million in 2020. Our operating loss in 2020 included $2,825 million of non-cash full cost ceiling test impairments. Excluding the impact of ceiling test impairments, operating income (loss) increased $2,622 million compared to the same period in 2020 primarily due to a 144% increase in our weighted average realized commodity prices, excluding derivatives, and a 41% increase in production volumes, of which 80% was related to the Montage Merger and the Indigo Merger (as defined herein).
- Our E&P segment cash flow from operations was $1,718 million in 2021, compared to $372 million in 2020. E&P segment cash flow from operations increased $1,346 million as a 30% increase in our net weighted average realized commodity prices, including settled derivatives, and a 41% increase in production volumes was only partially offset by a 46% increase in operating costs and expenses.

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, dampens inflationary pressures, promotes operating efficiency, enables quick reaction to rapid changes in market conditions and helps to mitigate certain operational and environmental risks. These services include drilling, completions and water management and movement. As of December 31, 2021, we operated a fleet of drilling rigs and have leased a pressure pumping spread with a total capacity of 51,000 horsepower along with additional supporting pump down equipment with a total capacity of 36,000 horsepower. These assets provide us greater flexibility to align our operational activities with commodity prices. In 2021, we provided drilling rigs for 74 drilled wells.

Our Proved Reserves

	For the years ended December 31,		
	2021	2020	
Proved reserves: *(Bcfe)*			
Appalachia	15,527	11,989	
Haynesville	5,621	—	
Other	—	1	
Total proved reserves	21,148	11,990	
Prices used:			
Natural gas *(per Mcf)*	$ 3.60	$ 1.98	
Oil *(per Bbl)*	$ 66.56	$ 39.57	
NGL *(per Bbl)*	$ 28.65	$ 10.27	
PV-10: *(in millions)*			
Pre-tax (1)	$ 22,420	$ 1,847	
PV of taxes	(3,689)	—	(2)
After-tax	$ 18,731	$ 1,847	
Percent of estimated proved reserves that are:			
Natural gas	82 %	76 %	
Proved developed	54 %	68 %	
Percent of E&P operating revenues generated by natural gas sales	72 %	69 %	

(1) Pre-tax PV-10 is a non-GAAP financial measure. We believe that the presentation of pre-tax PV-10 is relevant and useful to our investors as supplemental disclosure to the standardized measure of discounted future cash flows ("standardized measure"), or after-tax PV-10 amount, because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account future corporate income taxes and our current tax structure. While the standardized measure is dependent on the unique tax situation of each company, pre-tax PV-10 is based on a pricing methodology and discount factors that are consistent for all companies. Because of this, pre-tax PV-10 can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis. The difference between the standardized measure and the pre-tax PV-10 amount is the discounted amount of estimated future income taxes. See "Supplemental Oil and Gas Disclosures (Unaudited)" to the consolidated financial statements of this Annual Report for more information about the calculation of standardized measure.

(2) 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 year-end 2021 reserve estimates totaled 21.1 Tcfe with an after-tax PV-10 of $18.7 billion. Our reserve estimates and the after-tax PV-10 measure, or standardized measure, are highly dependent upon the respective commodity price used in our reserve and after-tax PV-10 calculations.

- Our reserves increased 76% in 2021, compared to 2020, primarily due to the reserves acquired from Indigo and GEPH as well as an increase in commodity pricing.
- Our after-tax PV-10 value increased in 2021 compared to 2020 primarily due to an increase in the SEC 12-month backward-looking commodity prices as well as higher reserve levels resulting from the recent acquisitions.
- We are the designated operator of approximately 98% of our reserves, based on the pre-tax PV-10 value of our proved developed producing reserves, and our reserve life index was approximately 12.6 years at year-end 2021, using an estimate of full year production from our recently acquired Indigo and GEPH properties.

The difference in after-tax PV-10, or standardized measure, and pre-tax PV-10 (a non-GAAP measure which is reconciled in the 2021 Proved Reserves by Category and Summary Operating Data table below) is the discounted value of future income taxes on the estimated cash flows.

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 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 "Cautionary Statement about Forward-Looking Statements" in this Annual Report for a discussion of the risks inherent in utilization of standardized measure and estimated reserve data.

Lower natural gas, oil and NGL prices can 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 2021 based on average year prices, and our well count, net acreage and PV-10 as of December 31, 2021, and sets forth 2021 annual information related to production and capital investments for each of our operating areas:

2021 PROVED RESERVES BY CATEGORY AND SUMMARY OPERATING DATA

	Appalachia	Haynesville	Other [1]	Total
Estimated proved reserves:				
Natural gas *(Bcf)*:				
Developed	7,382	1,926	—	**9,308**
Undeveloped	4,207	3,692	—	**7,899**
	11,589	5,618	—	**17,207**
Crude oil *(MMBbls)*:				
Developed	40.7	0.2	—	**40.9**
Undeveloped	38.8	—	—	**38.8**
	79.5	0.2	—	**79.7**
Natural gas liquids *(MMBbls)*:				
Developed	296.7	0.2	—	**296.9**
Undeveloped	280.1	—	—	**280.1**
	576.8	0.2	—	**577.0**
Total proved reserves *(Bcfe)* [2]:				
Developed	9,406	1,929	—	**11,335**
Undeveloped	6,121	3,692	—	**9,813**
	15,527	5,621	—	**21,148**
Percent of total	73%	27%	—%	**100%**
Percent proved developed	61%	34%	—%	**54%**
Percent proved undeveloped	39%	66%	—%	**46%**
Production *(Bcfe)*	1,108	132	—	**1,240**
E&P capital investments *(in millions)*	$ 882	$ 200	$ 25 [3]	**$ 1,107**
Total gross producing wells [4]	1,749	1,155	—	**2,904**
Total net producing wells	1,390	709	—	**2,099**
Total net acreage	768,050	256,727 [5]	12,887 [6]	**1,037,664**
Net undeveloped acreage	476,512	15,725 [7]	650 [6]	**492,887**
PV-10:				
Pre-tax *(in millions)* [8]	$ 15,507	$ 6,917	$ (4) [9]	**$ 22,420**
PV of taxes *(in millions)* [8]	(2,552)	(1,138)	1	**(3,689)**
After-tax *(in millions)* [8]	$ 12,955	$ 5,779	$ (3) [9]	**$ 18,731**
Percent of total	69%	31%	—%	**100%**
Percent operated [10]	98%	96%	100%	**98%**

(1) Other 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 $5 million related to our water infrastructure project, $17 million related to our E&P service companies and $3 million related to other developmental activities.

(4) Excludes 884 wells in Appalachia and 191 wells in Haynesville in which we only have an overriding royalty interest. These wells were included in the December 31, 2021 reserves calculation.

(5) Excludes 30,744 net acres of minerals owned, of which 4,259 acres are leased by others. Minerals in Louisiana are subject to prescription beginning in 2024. The minerals underlying the Haynesville area are subject to expiration in 2027 if no drilling or production occurs on the associated acreage.

(6) Excludes exploration licenses for 2,518,519 net acres in New Brunswick, Canada, which have been subject to a moratorium since 2015. In 2021, we were granted a further extension of the licenses through March 2026. However, we cannot assure that the licenses will be extended past that date.

(7) Excludes 20,187 net acres of company-owned minerals.

(8) Pre-tax PV-10 is a non-GAAP financial measure. We believe that the presentation of pre-tax PV-10 is relevant and useful to our investors as supplemental disclosure to the standardized measure of discounted future cash flows (standardized measure), or after-tax PV-10 amount, because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account future corporate income taxes and our current tax structure. While the standardized measure is dependent on the unique tax situation of each company, pre-tax PV-10 is based on a pricing methodology and discount factors that are consistent for all companies. Because of this, pre-tax PV-10 can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis. The difference between the standardized measure and the pre-tax PV-10 amount is the discounted amount of estimated future income taxes. See "Supplemental Oil and Gas Disclosures (Unaudited)" to the consolidated financial statements of this Annual Report for more information about the calculation of standardized measure.

(9) Includes future asset retirement obligations outside of Appalachia and Haynesville.

(10) 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:	2022	2023	2024
Appalachia [(2)]	32,289 [(1)]	16,059	15,682
Haynesville	3,899 [(1)]	3,059	2,143
Other			
US – Other Exploration	650	—	—
US – Sand Wash Basin	—	—	—
Canada – New Brunswick [(3)]	—	—	—

(1) We have no reported proved undeveloped locations expiring in 2022.

(2) The leasehold acreage expiring includes 16,596 net acres in 2022, 6,914 net acres in 2023 and 6,350 net acres in 2024 can be extended for an average 5.0 years.

(3) Exploration licenses were extended through March 2026 but have been subject to a moratorium since 2015. 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 "Cautionary Statement about Forward-Looking Statements" in this Annual Report for a discussion of the risks inherent in utilization of standardized measure and estimated reserve data.

Proved Undeveloped Reserves

Presented below is a summary of changes in our proved undeveloped reserves for 2020 and 2021:

CHANGES IN PROVED UNDEVELOPED RESERVES

(in Bcfe)	**Appalachia**	**Haynesville**	**Total**
December 31, 2019	**6,300**	**—**	**6,300**
Extensions, discoveries and other additions	474	—	**474**
Performance and production revisions (1)	567	—	**567**
Price revisions	(3,288)	—	**(3,288)**
Developed	(1,487)	—	**(1,487)**
Disposition of reserves in place	—	—	**—**
Acquisition of reserves in place	1,221	—	**1,221**
December 31, 2020	**3,787**	**—**	**3,787**
Extensions, discoveries and other additions	3,511	—	**3,511**
Performance and production revisions (1)	(28)	—	**(28)**
Price revisions	4	—	**4**
Developed	(1,153)	—	**(1,153)**
Disposition of reserves in place	—	—	**—**
Acquisition of reserves in place	—	3,692	**3,692**
December 31, 2021	**6,121**	**3,692**	**9,813**

(1) Primarily due to changes associated with the analysis of updated data collected in the year.

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, 2021, we had 9,813 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 2021, we invested $388 million in connection with converting 1,153 Bcfe, or 30%, of our proved undeveloped reserves as of December 31, 2020 into proved developed reserves and added 3,511 Bcfe of proved undeveloped reserves. Additionally, we added 3,692 Bcfe of proved undeveloped reserves through the Indigo Merger and GEPH Merger. These additions were partially offset by a 24 Bcfe net decrease due to price, performance and production revisions.

- As of December 31, 2020, we had 3,787 Bcfe of proved undeveloped reserves. 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.

- Our proved reserves as of December 31, 2021 included no proved undeveloped reserves that had a positive present value on an undiscounted basis in compliance with proved reserve requirements but did not have a positive present value when discounted at 10%.

We expect that the development costs for our proved undeveloped reserves of 9,813 Bcfe as of December 31, 2021 will require us to invest an additional $5.6 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. 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 "Cautionary Statement about Forward-Looking Statements" in this Annual Report for a more detailed discussion of these factors and other risks.

Preparation of Reserve Estimates

Our proved reserve estimates as of December 31, 2019, 2020 and 2021 included in this Annual Report were prepared by our internal reservoir engineers under the supervision of our management, in accordance with petroleum engineering and evaluation standards published by the Society of Petroleum Evaluation Engineers and definitions and guidelines established by the SEC. These proved reserve estimates have been audited by our independent engineers, Netherland, Sewell & Associates, Inc. ("NSAI").

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 27 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 33 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 24 years and over 20 years of practical experience in petroleum geosciences and petroleum engineering, respectively; (2) have over 13 years and over 20 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.

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. We believe the reserve replacement ratio is an important analytical measure used by investors and peers in the E&P industry to evaluate performance results and long-term prospects. Reserve replacement represents the net change in reserves, net of production, divided by our current year production, as shown in our supplemental reserve table disclosures. The reserve replacement ratio is a statistical indicator that has limitations, including its predictive and comparative value. As an annual measure, the reserve replacement ratio can be limited because it may vary widely based on the extent and timing of new discoveries and the varying effects of changes in prices and well performance. In addition, because the reserve replacement ratio does not consider the cost or timing of future production of new reserves or the type of reserves, such measure may not be an adequate measure of value creation.

Excluding the Haynesville acquisitions, we organically replaced 382% of our production volumes in 2021 with 4,231 Bcfe of proved reserve additions and performance revisions. Our recently acquired properties in the Haynesville separately accounted for 61% of the increase in total reserves in 2021, as compared to the prior year. The following table summarizes the changes in our proved natural gas, oil and NGL reserves for the year ended December 31, 2021:

(in Bcfe)	Appalachia	Haynesville	Other [(1)]	**Total**
December 31, 2020	**11,989**	**—**	**1**	**11,990**
Net revisions				
Price revisions	415	—	—	**415**
Performance and production revisions	270	—	(1)	**269**
Total net revisions	685	—	(1)	**684**
Extensions, discoveries and other additions				
Proved developed	451	—	—	**451**
Proved undeveloped	3,511	—	—	**3,511**
Total reserve additions	3,962	—	—	**3,962**
Production	(1,108)	(132)	—	**(1,240)**
Acquisition of reserves in place	—	5,753	—	**5,753**
Disposition of reserves in place	(1)	—	—	**(1)**
December 31, 2021	**15,527**	**5,621**	**—**	**21,148**

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

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 “Cautionary Statement about Forward-Looking Statements” in this Annual Report for a more detailed discussion of these factors and other risks.

Our Operations

Appalachia

Appalachia represented 89% of our total 2021 net production and 73% of our total reserves as of December 31, 2021. Given that we began operating in the Haynesville in the latter part of 2021 as a result of the Indigo Merger and the GEPH Merger, we expect the percentage of production represented by our operations in Appalachia to decrease in 2022. In 2021, our production increased by 228 Bcfe. Our reserves in Appalachia increased by 3,538 Bcf, as net additions of 3,962 Bcfe, net upward price revisions of 415 Bcfe and net upward performance revisions of 270 Bcfe were only partially offset by production of 1,108 Bcfe. As of December 31, 2021, we had approximately 768,050 net acres in Appalachia and had a total of 1,527 wells on production that we operated. Below is a summary of Appalachia's operating results for the latest two years:

	For the years ended December 31,	
	2021	2020
Acreage		
Net undeveloped acres	476,512 (1)	514,788
Net developed acres	291,538	274,430
Total net acres	768,050	789,218
Net Production		
Natural gas *(Bcf)*	883	694
Oil *(MBbls)*	6,567	5,124
NGL *(MBbls)*	30,936	25,923
Total production *(Bcfe)*	1,108	880
Reserves		
Reserves *(Bcfe)*	15,527	11,989
Locations:		
Proved developed producing (2)	1,749	2,577
Proved developed non-producing (3)	41	171
Proved undeveloped	334	208
Total locations	2,124	2,956
Gross Operated Well Count Summary		
Drilled	74	98
Completed	78	96
Wells to sales	78	100
Capital Investments *(in millions)*		
Drilling and completions, including workovers	$ 694	$ 681
Acquisition and leasehold	41	37
Seismic and other	7	10
Capitalized interest and expense	140	144
Total capital investments (4)	$ 882	$ 872
Average completed well cost *(in millions)* (5)	$ 9.1	$ 8.1
Average lateral length *(feet)* (5)	14,332	12,154

(1) Our undeveloped acreage position as of December 31, 2021 had an average royalty interest of 14.75%.

(2) Excludes 884 and 686 wells as of December 31, 2021 and 2020, respectively, in which we have only an overriding royalty interest.

(3) Excludes 16 and 54 wells as of December 31, 2021 and 2020, respectively, in which we have only an overriding royalty interest.

(4) Excludes $5 million and $9 million for the years ended December 31, 2021 and 2020, respectively, related to water infrastructure.

(5) Average completed well cost and average lateral length for the years ended December 31, 2021 and 2020 include wells in the Marcellus and Utica formations.

For 2021 as compared to 2020:

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

Our ability to bring our 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 Appalachia production.

Haynesville

On September 1, 2021, we acquired our initial Haynesville properties through the Indigo Merger. Our Haynesville production volumes reflect four months of production from these properties. On December 31, 2021, we acquired additional Haynesville properties through our GEPH Merger. Our reported Haynesville reserves as of December 31, 2021 reflects this addition. Haynesville represented 11% of our total 2021 net production and 27% of our total reserves as of December 31, 2021. Given that we began operating in the Haynesville in the latter part of 2021 as a result of these mergers, we expect the percentage of production represented by our operations in the Haynesville to increase in 2022. In 2021, our production in Haynesville was 132 Bcfe. Our reserves in Haynesville were 5,621 Bcfe as of December 31, 2021, as the acquisition of 5,753 Bcfe in 2021 was only partially offset by production of 132 Bcfe. As of December 31, 2021, we had approximately 256,727 net acres in Haynesville and had a total of 761 wells on production that we operated. Below is a summary of our Haynesville operating results for 2021:

		For the year ended December 31, 2021
Acreage		
Net undeveloped acres [(1)]		15,725
Net developed acres		241,002
Total net acres		256,727
Net Production		
Natural gas *(Bcf)*		132
Oil *(MBbls)*		8
Total production *(Bcfe)*		132
Reserves		
Reserves *(Bcfe)*		5,621
Locations:		
Proved developed producing [(2)]		1,155
Proved developed non-producing [(3)]		111
Proved undeveloped		329
Total locations		1,595
Gross Operated Well Count Summary		
Drilled		13
Completed		15
Wells to sales		15
Capital Investments *(in millions)*		
Drilling and completions, including workovers	$	178
Acquisition and leasehold		1
Capitalized interest and expense		21
Total capital investments	$	200
Average completed well cost *(in millions)* [(4)]	$	11.1
Average lateral length *(feet)* [(4)]		6,692

(1) Our undeveloped acreage position as of December 31, 2021 had an average royalty interest of 22%.

(2) Excludes 191 as of December 31, 2021 in which we have only an overriding royalty interest.

(3) Excludes 17 wells as of December 31, 2021 in which we have only an overriding royalty interest.

(4) Average completed well cost and average lateral length for wells placed to sales following the Indigo Merger on September 1, 2021 includes wells drilled and completed by previous operator. The GEPH Merger closed on December 31, 2021, and no wells acquired from GEPH were placed to sales in 2021.

Our continued ability to bring our Haynesville 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 Haynesville 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 650 net undeveloped acres for the potential development of new resources as of December 31, 2021 in areas outside of Appalachia and Haynesville. This compares to 9,764 net undeveloped acres held at year-end 2020 in areas outside of Appalachia and Haynesville, excluding the New Brunswick acreage.

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 were granted an extension of the 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. In 2021, we were granted a further extension of the licenses through March 2026. Unless and until the moratorium is lifted, we will not be able to develop these assets.

Acquisitions and Divestitures

In November 2020, we closed on our Agreement and Plan of Merger with Montage Resources Corporation ("Montage"), pursuant to which Montage merged with and into Southwestern (the "Montage Merger"). At the effective time of the Montage 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 Montage Merger increased our footprint in West Virginia and Pennsylvania and expanded our operations into Ohio.

On September 1, 2021, we closed on our Agreement and Plan of Merger with Ikon Acquisition Company, LLC ("Ikon"), Indigo Natural Resources LLC ("Indigo") and Ibis Unitholder Representative LLC, pursuant to which Indigo merged with and into Ikon, a subsidiary of Southwestern, and became a subsidiary of Southwestern (the "Indigo Merger"). The outstanding equity interests in Indigo were cancelled and converted into the right to receive (i) $373 million in cash consideration, and (ii) 337,827,171 shares of Southwestern common stock. Additionally, we assumed $700 million in aggregate principal amount of Indigo's 5.375% Senior Notes due 2029 (the "Indigo Notes"). The shares of Southwestern common stock had an aggregate dollar value equal to $1,588 million, based on the closing price of $4.70 per share of Southwestern common stock on the NYSE on September 1, 2021. The Indigo Merger diversified our operations by expanding our portfolio into the Haynesville and Bossier formations, deepened our inventory of economic wells, reduced our enterprise risk profile and gave us additional exposure to the LNG and other markets on the U.S. Gulf Coast.

On December 31, 2021, we closed on our Agreement and Plan of Merger with GEP Haynesville, LLC ("GEPH"), pursuant to which we acquired GEPH for aggregate consideration of approximately $1,732 million, consisting of a combination of $1,269 million cash and 99,337,748 shares of our common stock, with GEPH becoming our wholly owned subsidiary (the "GEPH Merger" and, together with the Montage Merger and the Indigo Merger, the "Mergers"). The shares issued as consideration had an aggregate dollar value equal to approximately $463 million based on the closing price of $4.66 per share of Southwestern common stock on the NYSE on December 31, 2021. The GEPH Merger furthered the benefits of the Indigo Merger and enhanced our scale and operating and marketing optionality in the Haynesville.

See Note 2 to the consolidated financial statements of this Annual Report for more information on the Mergers.

Capital Investments

(in millions)	For the years ended December 31, 2021	2020
E&P Capital Investments by Type		
Exploratory and development drilling, including workovers	$ 886	$ 692
Acquisition of properties	43	37
Water infrastructure project	5	9
Other	12	17
Capitalized interest and expenses	161	144
Total E&P capital investments (1)	$ 1,107	$ 899
E&P Capital Investments by Area		
Appalachia	$ 882	$ 872
Haynesville	200	—
Other (2)	25	27
Total E&P capital investments (1)	$ 1,107	$ 899

(1) Excludes $1 million for the year ended December 31, 2021 related to corporate capital investing.

(2) Includes $5 million and $9 million for the years ended December 31, 2021 and 2020, respectively, related to water infrastructure.

Our E&P capital investing in 2021 totaled $1.1 billion.

- E&P capital investing in 2021 increased 23%, as compared to the prior year, as we applied our capital discipline to our recently-acquired natural gas and oil properties, investing at levels designed to maintain daily production consistent with the end of the prior year.
- In 2021, we drilled 87 wells, completed 93 wells, placed 93 wells to sales and had 70 wells in progress at year-end.
- Of the 70 wells in progress at year-end, 33 were located in Appalachia and 37 were located in Haynesville.

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 2022.

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, 2021	2020
Average net daily production *(MMcfe/day)*	3,397	2,403
Production:		
Natural gas *(Bcf)*	1,015	694
Oil *(MBbls)*	6,610	5,141
NGLs *(MBbls)*	30,940	25,927
Total production *(Bcfe)*	1,240	880

- The increase in production volumes in 2021 resulted primarily from a 228 Bcfe increase in net production in Appalachia and 132 Bcf of production from our recently-acquired Haynesville properties. Production for the years ended December 31, 2021 and 2020 included 185 Bcfe and 28 Bcfe, respectively, from our acreage acquired through the Montage Merger.

Average Realized Prices

	For the years ended December 31,	
	2021	2020
Natural Gas Price:		
NYMEX Henry Hub Price *($/MMBtu)* (1)	$ 3.84	$ 2.08
Discount to NYMEX (2)	(0.53)	(0.74)
Average realized gas price, excluding derivatives *($/Mcf)*	$ 3.31	$ 1.34
Gain on settled financial basis derivatives *($/Mcf)*	0.09	0.11
Gain (loss) on settled commodity derivatives *($/Mcf)*	(1.12)	0.25
Average realized gas price, including derivatives *($/Mcf)*	$ 2.28	$ 1.70
Oil Price:		
WTI oil price *($/Bbl)* (3)	$ 67.92	$ 39.40
Discount to WTI (4)	(9.12)	(10.20)
Average realized oil price, excluding derivatives *($/Bbl)*	$ 58.80	$ 29.20
Gain (loss) on settled derivatives *($/Bbl)*	(18.32)	17.71
Average realized oil price, including derivatives *($/Bbl)*	$ 40.48	$ 46.91
NGL Price:		
Average realized NGL price, excluding derivatives *($/Bbl)*	$ 28.72	$ 10.24
Gain (loss) on settled derivatives *($/Bbl)*	(10.52)	0.91
Average realized NGL price, including derivatives *($/Bbl)*	$ 18.20	$ 11.15
Percentage of WTI, excluding derivatives	42 %	26 %
Total Weighted Average Realized Price:		
Excluding derivatives *($/Mcfe)*	$ 3.74	$ 1.53
Including derivatives *($/Mcfe)*	$ 2.53	$ 1.94

(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.

(3) Based on the average daily settlement price of the nearby month futures contract over the period.

(4) This discount primarily includes location and quality adjustments.

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 adverse price movements. We limit derivative agreements to counterparties with appropriate credit standings, and our policies prohibit speculation.

As of December 31, 2021, we had the following commodity price derivatives in place on our targeted future production:

	For the years ended December 31,		
	2022	2023	2024
Natural gas *(Bcf)*	1,297	923	279
Oil *(MBbls)*	4,583	2,114	54
Ethane *(MBbls)*	5,932	432	—
Propane *(MBbls)*	6,674	518	—
Normal Butane *(MBbls)*	1,587	164	—
Natural Gasoline *(MBbls)*	1,840	157	—
Total financial protection on future production *(Bcfe)*	1,421	943	279

As of February 25, 2022, we had the following commodity price derivatives in place on our targeted 2022 and future production:

	For the years ended December 31,		
	2022	2023	2024
Natural gas *(Bcf)*	1,297	937	279
Oil *(MBbls)*	4,584	2,115	603
Ethane *(MBbls)*	5,932	1,089	—
Propane *(MBbls)*	6,674	883	—
Normal Butane *(MBbls)*	1,807	329	—
Natural Gasoline *(MBbls)*	1,840	314	—
Total financial protection on future production *(Bcfe)*	1,422	965	282

We intend to use derivatives to limit the impact of adverse price movements 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, 2021.

During 2021, the average price we received for our natural gas production, excluding the impact of derivatives and including the cost of transportation, was approximately $0.53 per Mcf lower than average NYMEX prices, an improvement of 28% over the prior year differential. Differences between NYMEX and price realized (basis differentials) are due primarily to locational differences and transportation cost.

The tables below present the amount of our future natural gas production in which the impact of basis volatility has been limited through derivatives and physical sales arrangements as of December 31, 2021:

	Volume *(Bcf)*	Basis Differential
Basis Swaps – Natural Gas		
2022	322	$ (0.38)
2023	200	(0.45)
2024	46	(0.71)
2025	9	(0.64)
Total	577	
Physical NYMEX Sales Arrangements – Natural Gas [1]		
2022	645	$ (0.11)
2023	521	(0.08)
2024	389	(0.06)
2025	308	(0.04)
2026	134	0.00
2027	125	0.01
2028	125	0.01
2029	125	0.01
2030	47	0.00
Total	2,419	

(1) Physical sales volumes are presented on a gross basis.

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, 2021, we had natural gas delivery commitments of 1,224 Bcf in 2022 and 730 Bcf in 2023 under existing agreements. These amounts are well below our expected 2022 natural gas production from Appalachia and Haynesville and expected 2023 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 LNG exporters, major energy companies, utilities and industrial purchasers of natural gas. For the year ended December 31, 2021, one purchaser accounted for 12% of our revenues. If we had completed the Indigo Merger and the GEPH Merger at the beginning of 2021, this same purchaser would have accounted for approximately 16% of our revenues. A default or operational disruption on this account could have a material impact on the Company. For the year ended December 31, 2020, one purchaser accounted for 10% of our revenues. No other purchasers accounted for more than 10% of consolidated revenues.

Competition

All phases of the natural gas and associated liquids 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. Regulations additionally govern the handling, transport and disposal of the water involved in our development efforts. 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,	
	2021	2020
Marketing revenues *(in millions)*	$ 6,186	$ 2,145
Other revenues *(in millions)*	3	—
Total operating revenues *(in millions)*	$ 6,189	$ 2,145
Operating income (loss) *(in millions)*	$ 52	$ (7)
Volumes marketed *(Bcfe)*	1,542	1,138
Percent natural gas production marketed from affiliated E&P operations	95%	89%
Percent oil and NGL production marketed from affiliated E&P operations	82%	81%

- Marketing operating income increased $59 million for the year ended December 31, 2021, compared to 2020, primarily due to a $56 million increase in the marketing margin, as well as a $1 million increase in gas storage gains and $2 million in non-performance damages received, both recorded in other operating revenues.
- Marketing revenues increased in 2021, compared to 2020, primarily due to a 113% increase in the price received for volumes marketed and a 404 Bcfe increase in marketed volumes.
- The margin generated from marketing activities increased $56 million for the year ended December 31, 2021, as compared to the prior year, primarily due to a 36% increase in volumes marketed and a corresponding reduction in third-party purchases and sales, which were used in 2020 to optimize our transportation folio, due to increased affiliated volumes available for marketing.

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.

Appalachia. Our transportation portfolio for all products in Appalachia is highly diversified, allows us to capitalize on strengthening markets, including city-gate markets, and provides production flow assurance. Agreements with Rover Pipeline LLC and Mountaineer Xpress / Gulf Xpress pipelines allow us to access growing high-demand markets in the U.S. Gulf Coast region while low-cost transportation on other northeast pipelines allows us to capture in-basin pricing, and our agreements with Rover Pipeline LLC and Rockies Express Pipeline LLC provide access to Midwest markets. In addition to our natural gas transportation, we have ethane take-away capacity that provides direct access to Mont Belvieu pricing. Certain of our 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, 2022:

	For the year ended December 31,		
(MMBtu/d)	2022	2023	2024
Firm transportation [(1)]	2,338,067	2,240,893	1,968,992
Firm sales	524,079	169,439	115,755
Total firm takeaway – Appalachia	2,862,146	2,410,332	2,084,747

(1) We have extension options and potential contract renewal capacity of 120,000 MMBtu per day for 2023 and 160,000 MMBtu per day for 2024 for Appalachia.

Haynesville. Our transportation portfolio for Haynesville allows for access to the U.S. Gulf Coast and LNG corridor markets. Agreements with ETC Tiger, Gulf South and Enable Line CP provide transport to the Southeast Supply Header ("SESH") and Perryville Hub, a central trading location with high demand and amply liquidity, while Acadian, Midcoast and LEAP pipelines deliver to the growing LNG corridor, with direct access to LNG shippers at sales prices close to Henry Hub pricing. Our diversified transportation portfolio provides flow optionality and allows for advantageous pricing year-round as the Haynesville maintains stability in basis throughout the year. The table below details our natural gas firm transportation, firm sales and total takeaway capacity over the next three years as of February 25, 2022:

	For the year ended December 31,		
(MMBtu/d)	2022	2023	2024
Firm transportation	1,325,000	1,225,000	1,225,000
Firm sales	1,066,096	975,890	950,000
Total firm takeaway – Haynesville	2,391,096	2,200,890	2,175,000

Demand Charges

As of December 31, 2021, our obligations for demand and similar charges under the firm transportation agreements and gathering agreements totaled approximately $10.5 billion, $872 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 $869 million of that amount. We regularly monitor our proved reserves to ensure sufficient availability to fully utilize our firm transportation commitments.

In the first quarter of 2019, we agreed to purchase firm transportation with pipelines in Appalachia starting in 2021 and running through 2032 totaling $327 million in total remaining contractual commitments, of which the seller has agreed to reimburse us for $100 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 "Our business depends on access to natural gas, oil and NGL gathering, processing and transportation systems and facilities. Changes to access and cost of these systems and facilities could adversely impact our business and financial condition. Our commitments to assure availability of transportation could lead to substantial payments for capacity we do not use if production falls below projected levels," 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 LNG exporters, major energy companies, utilities and industrial purchasers of natural gas. For the year ended December 31, 2021, one purchaser accounted for 12% of our revenues. If we had completed the Indigo Merger and the GEPH Merger at the beginning of 2021, this same purchaser would have accounted for approximately 16% of our revenues. A default or operational disruption on this account could have a material impact on the Company. For the year ended December 31, 2020, one purchaser accounted for 10% of our revenues. No other purchasers accounted for more than 10% of consolidated revenues.

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 laws and regulations governing protection of the environment and natural resources 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 strict, 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 more stringent handling, disposal and clean-up requirements. If such measures were 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. Oil accounted for 3% of our total production in 2021 and 4% in 2020 and 2019.

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 taking steps to regulate methane and other emissions from oil and natural gas activities, and further regulation could increase our costs or restrict our ability to produce. For example, on November 15, 2021, the U.S. Environmental Protection Agency ("EPA") issued a proposed rule under the Clean Air Act's New Source Performance Standards ("NSPS"), known as Subpart OOOOa, which is intended to reduce methane emissions from new and existing oil and gas sources. The proposed rule would make the existing regulations in Subpart OOOOa more stringent and create a Subpart OOOOb to expand reduction requirements for new, modified, and reconstructed oil and gas sources, including standards focusing on certain source types that have never been regulated under the CAA (including intermittent vent pneumatic controllers, associated gas, and liquids unloading facilities). In addition, the proposed rule would establish "Emissions Guidelines," creating a Subpart OOOOc that would require states to develop plans to reduce methane emissions from existing sources that must be at least as effective as presumptive standards set by the EPA. Under the proposed rule, states would have three years to develop their compliance plan for existing sources and the regulations for new sources would take effect immediately upon issuance of a final rule. The EPA is expected to issue both a supplemental proposed rule, that may expand or modify the current proposed rule, and final rule by the end of 2022. In addition, 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 and listed 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. In addition to the EPA's Subpart OOOO regulations discussed above, the EPA finalized pretreatment standards that 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 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, the EPA released a 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.

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 and 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 past 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, which could result in increased costs for their services to dispose of waste water from our operations.

Greenhouse Gas Emissions and Climate Change. 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. However, the United States House of Representatives passed H.R. 5376, known as the Build Back Better Act on November 3, 2021. The House version of the bill targets methane emissions from oil and gas sources by proposing to implement fees for excess methane leaking from wells, storage sites and pipelines as well as fees for new producing and non-producing oil and gas leases and offshore pipelines. The United States Senate did not pass the House version of the Build Back Better Act, and it is unclear whether any portions of the bill will become law. 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 increased operating costs, including costs to monitor and report on greenhouse gas emissions, install new equipment to reduce emissions of greenhouse gases associated with our operations, acquire emissions allowances or comply with new regulatory requirements. In addition, these regulatory initiatives could drive down demand for our products, 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. While some new laws and regulations are prompting power producers to shift from coal to natural gas, which has a positive effect on demand, regulatory incentives or requirements to conserve energy, use alternative sources or reduce greenhouse gas emissions in product supply chains could reduce demand for the products we produce.

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. On June 1, 2017, the prior administration announced that the U.S. would withdraw from the Paris Agreement, which withdrawal became effective on November 4, 2020. However, on January 20, 2021, the current administration issued written notification to the United Nations of the United States' intention to rejoin the Paris Agreement, which became effective on February 19, 2021. In addition, in September 2021, the current administration publicly announced the Global Methane Pledge, a pact that aims to reduce global methane emissions at least 30% below 2020 levels by 2030. Since its formal launch at the United Nations Climate Change Conference ("COP26"), over 100 countries have joined the pledge. To the extent that the United States and other countries implement or impose climate change regulations on the oil and gas industry, it could have an adverse effect on our business.

The Company is committed to responsible energy development, and we recognize stakeholder concerns about climate change. We also understand that regulations and practices aimed at protecting the environment, and specifically reducing greenhouse gas emissions, can affect our business. We consider addressing these issues as part of our risk management process. We have published a climate change scenario analysis as a part of our 2021 Corporate Responsibility Report (which covers the year 2020 and is not incorporated by reference into this filing). This report and our corporate responsibility reporting is informed by recommendations from the Task Force on Climate-Related Financial Disclosures framework.

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 Amendments 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 Canadian federal, provincial and local environmental regulations.

<u>Human Capital</u>

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 tools and skills to work safely and to be successful.

Workplace Culture/Respect, Diversity, and Inclusion. Southwestern Energy is committed to respect in the workplace. We believe that sound, collaborative and respectful relationships among Company employees are essential to achieving and maintaining a high level of productivity and ethical business conduct. All employees participate in a program addressing workplace behavior and respect on an annual basis. We recognize that every person should be treated fairly, and that every employment-related decision should be based on merits and qualifications for a particular job, including capability, performance and reflection of our corporate mission and values. 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. We also seek to advance workplace respect, diversity and inclusion through actively recruiting with key diversity organizations, working to build a diverse and local talent pool by encouraging diversity in science, technology, engineering and math education. We intend to continue to support and expand diversity initiatives within our organization.

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.

Employee Engagement. Our human capital management objectives include identifying, recruiting, training, retaining, incentivizing and integrating our existing and additional employees. Our employee development programs aim to provide Company employees with the right tools, training and resources to be successful. We offer a range of development solutions targeted at meeting individual employees' needs, including technical and non-technical training programs. We also measure employee engagement and enablement through a bi-annual survey, which is administered by a third-party vendor, and then create and implement an action plan based on feedback from the survey.

We aim to offer and maintain market competitive compensation and benefit programs for all of our employees in order to attract and retain superior and diverse talent. Compensation is based on several primary factors, including performance, skills, years of experience, time in position and market data.

Employee Health and Safety. Southwestern Energy leaders, including senior management, are evaluated in part on and held accountable for the HSE performance of their teams. HSE considerations are important factors in our business decisions, and we work to 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 throughout the pandemic has been driven by our long-standing commitment to safety. We formed a cross-functional Incident Response Team ("IRT") in March 2020 to manage and oversee prolonged company-wide response and mitigation efforts. The IRT continues to meet at least weekly and advise senior management. Our employees and contractors remain subject to increased safeguards, 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 and modified protocols as necessary based on continuous monitoring of relevant data and guidance. We have also provided additional benefits to our employees, which include making the COVID-19 vaccine available to employees and their families who want it, COVID-19 testing for all office and field employees and their families and paid time off for non-exempt workers required to isolate or quarantine, and we continue to recommend that our employees receive COVID-19 booster vaccinations.

As of December 31, 2021, we had 938 total employees, a 4% increase compared to year-end 2020. None of our employees were covered by a collective bargaining agreement at year-end 2021. We believe that our relationships with our employees are good.

Seasonality

Weather conditions and seasonality affect the demand for and prices of natural gas, oil and NGLs. Due to these fluctuations, results of operations for quarterly interim periods may not be indicative of the results realized on an annual basis.

Address, Internet Website and Availability of Public Filings

Our principal executive offices are located at 10000 Energy Drive, Spring, Texas 77389, and our telephone number is (832) 796-1000. We also maintain offices in Tunkhannock, Pennsylvania; Morgantown, West Virginia; Zanesville, Ohio; Frierson, Louisiana; Coushatta, Louisiana and Gloster, Louisiana. Our website is located at www.swn.com.

We furnish or file our Annual Reports on Form 10-K, our Quarterly Reports on Form 10-Q, our Current Reports on Form 8-K and amendments to such reports and other documents with the SEC under the Exchange Act. The SEC also maintains an internet website at www.sec.gov that contains reports, proxy and information statements and other information regarding issuers, including us, that file electronically with the SEC. We also make these documents available free of charge at www.swn.com under the "Investors" link as soon as reasonably practicable after they are filed or furnished with the SEC.

Information on our website is not incorporated into this Annual Report on Form 10-K or our other filings with the SEC and is not a part of them.

Executive Officers of the Registrant

The following table shows certain information as of February 25, 2022 about our executive officers, as defined in Rule 3b-7 of the Securities Exchange Act of 1934:

Name	Age	Officer Position
William J. Way	62	President and Chief Executive Officer
Carl F. Giesler, Jr.	50	Executive Vice President and Chief Financial Officer
Clayton A. Carrell	56	Executive Vice President and Chief Operating Officer
Derek W. Cutright	44	Senior Vice President – Division Head
John P. Kelly	51	Senior Vice President – Division Head
Andy Huggins	41	Senior Vice President – Haynesville
Quentin Dyson	52	Senior Vice President – Operations Services
Jason Kurtz	51	Vice President – Marketing and Transportation
Chris Lacy	44	Vice President, General Counsel and Secretary
Carina Gillenwater	46	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. Giesler was appointed Executive Vice President and Chief Financial Officer in July 2021. Prior to that, he served as President and Chief Executive Officer and as a Director of SandRidge Energy, Inc., having been appointed to that position in April 2020. Prior to that, he served as President and Chief Executive Officer and as a Director of Jones Energy, Inc., beginning in 2018. Prior to that, he served as President and Chief Executive Officer and as a Director of Miller Energy Resources, Inc., beginning in 2014.

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 – Division Head 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 – Division Head 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. Huggins was appointed Senior Vice President of Haynesville in September 2021, having previously 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.

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.

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.

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 and basis differentials 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 2021 and 2020, the NYMEX settlement price for natural gas ranged from a low of $1.50 per MMBtu in July 2020 to a high of $6.20 per MMBtu in November 2021, and during these periods our production was 82% and 79% natural gas, 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 2021, we paid $1,492 million, net of amounts we received, in settlement of hedging arrangements due to increased commodity pricing.

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. Although general commodity prices increased in 2021, 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, 2021, we had $5.4 billion of debt outstanding, consisting principally of senior notes maturing in various increments from 2022 to 2032, $550 million of term loan borrowings maturing in 2027 and $460 million of borrowings under our 2018 credit facility (defined below), 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. A sustained drop in commodity prices, such as was generally experienced from 2014 to 2020, could reduce our revenues, profits and cash flow, cause us to record significant non-cash asset impairments and lead us to reduce both our level of capital investing and our workforce.

Significant capital investment is required to develop and 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 develop and 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 gathering, processing and transportation systems and facilities. Changes to access and cost of these systems and facilities could adversely impact our business and financial condition. 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 Haynesville, 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, 2021, our aggregate demand charge commitments under these firm transportation agreements and gathering agreements were approximately $10.5 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 64,030 and 9,101 net acres of our Appalachia and Haynesville 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.

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.

Natural gas and oil drilling and producing and transportation operations are complex and can be hazardous and may expose us to liabilities. Incidents related to HSE performance and our asset and operating integrity could adversely impact our business and financial condition.

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 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.

A large portion of our producing properties remain concentrated in the Appalachian basin, making us vulnerable to risks associated with operating in limited geographic areas.

A large portion of our producing properties currently are geographically concentrated in the Appalachian basin in Pennsylvania, West Virginia and Ohio. At December 31, 2021, approximately 73% of our total estimated proved reserves were attributable to properties located in the Appalachian basin. As a result, 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.

Many of our business operations depend on activities performed by third parties. Changes to availability, costs and performance of personnel, products and services provided by third parties could adversely impact our business and financial condition.

We rely on third-party service providers to perform necessary drilling and completion and other related operations. The ability of third-party service providers to perform such operations will depend on those service providers' ability to compete for and retain qualified personnel as well as their financial condition, economic performance and ability to access capital, which in turn will depend upon the supply and demand for natural gas, oil and NGLs, prevailing economic conditions, and financial, business and other factors. The failure of a third-party service provider to adequately perform operations could delay drilling or completion or reduce production from the property and adversely affect our financial condition and results of operations.

Changes to the ability of our customers to receive our products or meet their financial, performance and other obligations to us could adversely impact our business and financial condition.

In addition to credit risk related to receivables from commodity derivative contracts, our principal exposures to credit risk are through receivables resulting from the sale of our natural gas, oil and NGL production that we market to energy companies, end users and refineries ($903 million as of December 31, 2021). We are also subject to credit risk due to concentration of receivables with several significant customers. The largest purchaser of our products during the year ended December 31, 2021 accounted for approximately 12% of our product revenues. We do not require all of our customers to post collateral. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial condition.

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.

Changes to applicable U.S. tax laws and regulations could affect our business and future profitability.

New U.S. laws and policy relating to taxes may have an adverse effect on us and our business and future profitability. Further, existing U.S. tax laws, statutes, rules, regulations or ordinances could be interpreted, changed, modified or applied adversely to us. The current administration has set forth, and Congress is considering, several tax proposals that would make significant changes to U.S. federal income tax laws, if enacted. It is unclear whether Congress will enact these proposals or similar changes and, if enacted, how soon any such changes could take effect. 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 any such proposals, or any similar legislation, could have an adverse effect on our financial position, results of operations and cash flows.

Our ability to use our net operating loss carryforwards and certain other tax attributes will be limited.

At December 31, 2021, we had substantial amounts of net operating loss carryforwards ("NOLs") and other attributes for U.S. federal and state income tax purposes. Due to the issuance of common stock associated with the Indigo Merger, we incurred a cumulative ownership change under Sections 382 and 383 of the Internal Revenue Code ("Code"), and as such, our NOLs and other attributes prior to the acquisition are subject to an annual limitation under Section 382 of the Code of approximately $48 million. The ownership change and resulting annual limitation will result in the expiration of NOLs or other tax attributes otherwise available. At December 31, 2021, we had approximately $4 billion of federal NOL carryovers, of which approximately $3 billion have an expiration date between 2035 and 2037 and $1 billion have an indefinite carryforward life. We currently estimate that approximately $2 billion of these federal NOLs will expire before they are able to be used. If a subsequent ownership change were to occur as a result of future transactions in our common stock, our use of remaining U.S. tax attributes may be further limited.

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

Deferred tax assets, including NOLs, represent future savings of taxes that would otherwise be paid in cash. As discussed above, at December 31, 2021, we had substantial amounts of NOLs for U.S. federal and state income tax purposes. Our ability to utilize our 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 and the applicable U.S. federal income tax and foreign tax laws. If management concludes that it is more likely than not that some or all of the benefit from the deferred tax assets will not be realized, a valuation allowance will be recognized in the period that this conclusion is reached.

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 physical impacts of adverse weather may have a negative impact on our business and results of operations.

The physical effects of adverse weather conditions, such as increased frequency and severity of droughts, storms, floods and other climatic events, could adversely affect or delay demand for our products or cause us to incur significant costs in preparing for, or responding to, the effects of climatic events themselves. Potential adverse effects could include disruption of our production activities, including, for example, damages to our facilities from winds or floods, increases in our costs of operation or reductions in the efficiency of our operations, impacts on our personnel, supply chain or distribution chain, as well as potentially increased costs for insurance coverages in the aftermath of such effects. Our ability to mitigate the physical impacts of adverse weather conditions depends in part upon our disaster preparedness and response along with our business continuity planning.

Negative public perception regarding us and/or our industry and increasing attention to ESG matters could have an adverse effect on our business, financial condition and results of operations and damage our reputation.

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 increased litigation risk and regulatory, legislative and judicial 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.

Further, increasing attention to climate change, societal expectations on companies to address climate change, investor and societal expectations regarding voluntary ESG disclosures, generally, and fuel conservation measures, alternative fuel requirements, and increasing consumer demand for alternative forms of energy or energy efficiency initiatives or products may result in increased costs, reduced demand for our products, reduced profits, and negative impacts on our stock price and access to capital markets. Moreover, while we create and publish voluntary disclosures regarding ESG matters from time to time, some of the statements in those voluntary disclosures may be based on hypothetical expectations and assumptions that may or may not be representative of current or actual risks or events or forecasts of expected risks or events, including the costs associated therewith. Such expectations and assumptions are necessarily uncertain and may be prone to error or subject to misinterpretation given the long timelines involved and the lack of an established single approach to identifying, measuring and reporting on many ESG matters. In addition, organizations that provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their approach to ESG matters. Such ratings are used by some investors to inform their investment and voting decisions. Unfavorable ESG ratings could lead to increased negative investor sentiment toward us and our industry and to the diversion of investment to other industries, which could have a negative impact on our stock price and our access to and costs of capital. In addition, failure or a perception (whether or not valid) of failure to implement our

ESG strategy or achieve ESG goals, including any greenhouse gas emission goals, could damage our reputation, causing our investors or consumers to lose confidence in our Company and brands, and negatively impact our operations.

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 or as consideration for acquisitions, including significant offerings of new shares in 2015, 2016, 2020 and 2021. 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.

Loss of our key executive officers or other personnel, or an inability to attract and retain such officers and personnel, could negatively affect our business.

Our future success depends on the skills, experience and efforts of our key executive officers. The sudden loss of any of these executives' services or our failure to appropriately plan for any expected key executive succession could materially and adversely affect our business and prospects, as we may not be able to find suitable individuals to replace them on a timely basis, if at all. Additionally, we also depend on our ability to attract and retain qualified personnel to operate and expand our business. Workers may choose to pursue employment with our competitors or in other fields; this competition has become exacerbated by the increase in employee resignations currently taking place throughout the United States. If we fail to attract or retain talented new employees, our business and results of operations could be negatively affected.

The COVID-19 pandemic has negatively affected, and may in the future negatively affect, our business, operating results and financial condition.

COVID-19 has resulted in volatile economic conditions, business and supply chain disruptions and significant volatility and disruption of markets, particularly at the beginning of the pandemic. As a result of COVID-19, we have experienced, and may experience in the future, among other things, a reduction in demand for natural gas, oil, NGLs and other products derived therefrom, and may experience in the future reduced availability of personnel, equipment and services critical to our ability to operate our properties, which could in the future adversely impact, our business, results of operations and overall financial performance. Although several COVID-19 vaccines are currently being widely administered globally, the severity, magnitude and duration of the economic effects of the virus (including any emerging variants) continue to evolve, remain uncertain and may be impacted by various factors beyond our knowledge or control. As such, we might not be able to predict, or respond to, all impacts on a timely basis to prevent near- or long-term adverse impacts on our business, results of operations, financial condition and cash flows. These impacts may be material. Additionally, the impacts of the COVID-19 pandemic could have the effect of heightening many of the other risks described herein.

<u>Risks Related to our Indebtedness and Financing Abilities</u>

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, 2022, 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 2018 credit facility for other purposes. We had $160 million of letters of credit outstanding at December 31, 2021. 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, 2021, we had total indebtedness of $5.4 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 Indigo and GEPH consolidated EBITDAX prior to the respective Mergers for the same rolling twelve-month period. EBITDAX, as defined in our 2018 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, 2021, we were in compliance with all of the covenants of our 2018 credit facility. 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 2018 credit facility may negatively impact our ability to fund our operations, and we may not have sufficient funds to repay borrowings under our 2018 credit facility if required as a result of a borrowing base redetermination.

The amount we may borrow under our 2018 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, 2021, the elected borrowing base and total aggregate commitments were $2.0 billion, which was most recently reaffirmed as of October 2021. 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, 2021, we had $460 million of outstanding borrowings under our 2018 credit facility, and we expect to borrow under that facility in the future. As of December 31, 2021, we had $160 million of letters of credit issued under the 2018 credit facility and unused borrowing capacity was approximately $1.4 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 2018 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.

The elimination of LIBOR may adversely affect the cost of our borrowings.

Regulatory authorities in the U.K. ceased publication of certain LIBOR tenors after December 31, 2021 and will cease publication of all USD LIBOR tenors after June 30, 2023. In the U.S., the Alternative Reference Rates Committee has formally recommended forward-looking Secured Overnight Financing Rate ("SOFR") term rates. We anticipate using a variation of the LIBOR rate until our credit agreement is extended. We do not expect the replacement of LIBOR to result in a material impact to our financial statements; however, negotiations with respect to financing agreements could require us to incur incremental expenses and may subject us to disputes over the appropriateness or comparability of the relevant replacement reference index. In addition, there can be no assurance that the application of SOFR or any other alternative reference rate will not increase our interest expense or will not introduce operational risks in our accounting or financial reporting and other aspects of our business.

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 June 2016, the EPA finalized regulations establishing NSPS, known as Subpart OOOOa, for methane and volatile organic compounds from new and modified oil and natural gas production and natural gas processing and transmission facilities. In September 2020, the EPA finalized two sets of amendments to the 2016 Subpart OOOOa standards. The first, known as the 2020 Technical Rule, reduced the 2016 rule's fugitive emissions monitoring requirements and expanded exceptions to pneumatic pump requirements, among other changes. The second, known as the the 2020 Policy Rule, rescinded the methane-specific requirements for certain oil and natural gas sources in the production and processing segments. On January 20, 2021, the current administration issued an Executive Order directing the EPA to rescind the 2020 Technical Rule by September 2021 and consider revising the 2020 Policy Rule. On June 30, 2021, the current administration signed a Congressional Review Act (“CRA”) resolution passed by Congress that revoked the 2020 Policy Rule. The CRA resolution did not address the 2020 Technical Rule.

Further, on November 15, 2021, the EPA issued a proposed rule intended to reduce methane emissions from new and existing oil and gas sources. The proposed rule would make the existing regulations in Subpart OOOOa more stringent and create a Subpart OOOOb to expand reduction requirements for new, modified, and reconstructed oil and gas sources, including standards focusing on certain source types that have never been regulated under the CAA (including intermittent vent pneumatic controllers, associated gas, and liquids unloading facilities). In addition, the proposed rule would establish “Emissions Guidelines,” creating a Subpart OOOOc that would require states to develop plans to reduce methane emissions from existing sources that must be at least as effective as presumptive standards set by the EPA. Under the proposed rule, states would have three years to develop their compliance plan for existing sources and the regulations for new sources would take effect immediately upon issuance of a final rule. The EPA is expected to issue both a supplemental proposed rule, that may expand or modify the current proposed rule, and final rule by the end of 2022. As a result of these regulatory changes, the scope of any final methane regulations or the costs for complying with federal methane regulations are uncertain.

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. However, the United States House of Representatives passed H.R. 5376, known as the Build Back Better Act on November 3, 2021. The House version of the bill targets methane emissions from oil and gas sources by proposing to implement fees for excess methane leaking from wells, storage sites and pipelines as well as fees for new producing and non-producing oil and gas leases and off-shore pipelines. The United States Senate did not pass the House version of the Build Back Better Act, and it is unclear whether any portions of the bill will become law. 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 increased operating costs, including costs to monitor and report on greenhouse gas emissions, install new equipment to reduce emissions of greenhouse gases associated with our operations, acquire emissions allowances or comply with new regulatory requirements. In addition, these regulatory initiatives could drive down demand for our products, 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. While some new laws and regulations are prompting power producers to shift from coal to natural gas, which has a positive effect on demand, regulatory incentives or requirements to conserve energy, use alternative sources or reduce greenhouse gas emissions in product supply chains could reduce demand for the products we produce.

In December 2015, over 190 countries, including the United States, reached an agreement to reduce global greenhouse gas emissions. 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 withdrawal became effective in November 2020. However, on January 20, 2021, the current administration issued written notification to the United Nations of the United States' intention to rejoin the Paris Agreement, which became effective on February 19, 2021. In addition, in September 2021, the current administration publicly announced the Global Methane Pledge, a pact that aims to reduce global methane emissions at least 30% below 2020 levels by 2030. Since its formal launch at the United Nations Climate Change Conference (COP26), over 100 countries have joined the pledge. To the extent that the United States and other countries implement or impose 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 protection of the environment and natural resources, 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.

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

The trading price and volume of our common stock may be volatile, and you could lose a significant portion of your investment.

The market price of the common stock could be volatile, and holders of common stock may not be able to resell their common stock at or above the price at which they acquired such securities due to fluctuations in the market price of common stock. The stock markets in general have experienced extreme volatility that has often been unrelated to the operating performance of particular companies. These broad market fluctuations may adversely affect the trading price of the common stock. Specific factors that may have a significant effect on the market price for our common stock include:

- general economic conditions within the U.S. and internationally, including changes in interest rates;
- general market conditions, including fluctuations in commodity prices;
- domestic and international economic, legal and regulatory factors unrelated to our performance;

- changes in oil and natural gas prices;
- volatility in the financial markets or other global economic factors, including the impact of COVID-19;
- actual or anticipated fluctuations in our and our competitors' quarterly and annual results;
- quarterly variations in the rate of growth of our financial indicators;
- our business, operations, results and prospects;
- our operating and financial performance;
- future mergers and strategic alliances;
- market conditions in the energy industry;
- changes in government regulation, taxes, legal proceedings or other developments;
- shortfalls in our operating results from levels forecasted by securities analysts;
- investor sentiment toward the stock of oil and gas companies;
- changes in revenue or earnings estimates, or changes in recommendations by equity research analysts;
- failure to achieve the perceived benefits of the Mergers, including financial results and anticipated synergies, as rapidly as or to the extent anticipated by financial or industry analysts;
- speculation in the press or investment community;
- the failure of research analysts to cover our stock;
- sales of common stock by us, large shareholders or management, or the perception that such sales may occur;
- changes in accounting principles, policies, guidance, interpretations or standards;
- announcements concerning us or our competitors;
- public reaction to our press releases, other public announcements and filings with the SEC;
- strategic actions taken by competitors;
- actions taken by our shareholders;
- additions or departures of key management personnel;
- maintenance of acceptable credit ratings or credit quality; and
- the general state of the securities markets.

Additionally, we issued a substantial number of shares in connection with the Indigo Merger and the GEPH Merger. Certain restrictions on the resale by the holders such shares expire on March 1, 2022 and June 30, 2022, respectively. If our existing stockholders sell substantial amounts of our common stock in the public market, or if the public perceives that such sales could occur, this could have an adverse impact on the market price of our common stock, even if there is no relationship between such sales and the performance of our business.

These and other factors may impair the market for the common stock and the ability of investors to sell shares at an attractive price. These factors also could cause the market price and demand for the common stock to fluctuate substantially, which may negatively affect the price and liquidity of the common stock. Many of these factors and conditions are beyond our control.

Securities class action litigation has often been instituted against companies following periods of volatility in the overall market and in the market price of a company's securities. Such litigation, if instituted against us, could result in very substantial costs, divert management's attention and resources and harm our business, operating results and financial condition.

Market views of our industry generally can affect our stock price, liquidity and ability to obtain financing.

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 impact of 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 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. These rules were finalized in January of 2021 with compliance dates as early as January 1, 2022 for certain positions. In 2016, the CFTC finalized a companion rule on aggregation of positions among entities under common ownership or control. It is too early to determine the precise effect of these rules on our business, but they may have an impact on our ability to hedge our exposure to certain enumerated commodities (whether using futures contracts, over-the-counter derivatives contracts or otherwise).

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 Indigo Merger and the GEPH Merger

We may not achieve the anticipated benefits of the Indigo Merger and the GEPH Merger, and the Indigo Merger and the GEPH Merger may disrupt our current plans or operations.

The success of the Indigo Merger and the GEPH Merger will depend, in part, on our ability to realize the anticipated benefits and cost savings from combining our business and the businesses of Indigo and GEPH, and there can be no assurance that we will be able to successfully integrate such businesses or otherwise realize the anticipated benefits of the Indigo Merger and the GEPH Merger. Difficulties in integrating such businesses 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 such businesses in a manner that permits the achievement of full revenue, expected cash flows and cost savings anticipated from the Indigo Merger and the GEPH 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;
- integrating relationships with customers, vendors and business partners;
- performance shortfalls as a result of the diversion of management's attention caused by integrating the operations of such businesses; and
- the disruption of, or the loss of momentum in, our 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 2021 based on average fiscal-year prices, as required by Item 1202 of Regulation S-K, is included in the table headed "2021 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 and incorporated by reference in this Item 2.

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 production and 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."

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, 2021

	Undeveloped		Developed		Total	
	Gross	Net	Gross	Net	Gross	Net
Appalachia	655,767	476,512	347,521	291,538	1,003,288	768,050
Haynesville	36,223	15,725	306,774	241,002	342,997	256,727
Other:						
US – Other Exploration	1,105	650	5,034	2,263	6,139	2,913
US – Sand Wash Basin	—	—	14,977	9,974	14,977	9,974
Total US	693,095	492,887	674,306	544,777	1,367,401	1,037,664
Canada – New Brunswick (1)	2,518,519	2,518,519	—	—	2,518,519	2,518,519
	3,211,614	3,011,406	674,306	544,777	3,885,920	3,556,183

(1) The exploration licenses for 2,518,519 net acres in New Brunswick, Canada, were extended through March 2026 but have been subject to a moratorium since 2015. We fully impaired our investment in New Brunswick in 2016. Unless and until the moratorium is lifted, we will not be able to develop these assets.

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:	2022	2023	2024
Appalachia (1)	32,289	16,059	15,682
Haynesville	3,899	3,059	2,143
Other:			
US – Other Exploration	650	—	—
US – Sand Wash Basin	—	—	—
Canada – New Brunswick (2)	—	—	—

(1) The leasehold acreage expiring includes 16,596 net acres in 2022, 6,914 net acres in 2023 and 6,350 net acres in 2024 can be extended for an average 5.0 years.

(2) Exploration licenses were extended through March 2026 but have been subject to a moratorium since 2015. We fully impaired our investment in New Brunswick in 2016. Unless and until the moratorium is lifted, we will not be able to develop these assets.

Producing wells as of December 31, 2021

	Natural Gas		Oil		Total		Gross Wells Operated
	Gross	Net	Gross	Net	Gross	Net	
Appalachia	1,748	1,389.7	1	0.5	1,749	1,390.2	1,527
Haynesville	1,155	708.6	—	—	1,155	708.6	761
Other	—	—	—	—	—	—	—
	2,903	2,098.3	1	0.5	2,904	2,098.8	2,288

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

	Development					
	Productive Wells		Dry Wells		Total	
Year	Gross	Net	Gross	Net	Gross	Net
2021						
Appalachia	78.0	74.8	—	—	78.0	74.8
Haynesville (1)	15.0	14.5	—	—	15.0	14.5
Total	93.0	89.3	—	—	93.0	89.3
2020						
Appalachia	100.0	89.0	—	—	100.0	89.0
Haynesville (1)	—	—	—	—	—	—
Total	100.0	89.0	—	—	100.0	89.0
2019						
Appalachia	113.0	95.2	—	—	113.0	95.2
Haynesville (1)	—	—	—	—	—	—
Total	113.0	95.2	—	—	113.0	95.2

(1) The Haynesville E&P assets were acquired through the Indigo Merger in September 2021.

The Company drilled no exploratory wells (productive or dry) in any of its areas of operation during the three years ended December 31, 2021.

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, 2021

	Gross	Net
Drilling:		
Appalachia	13.0	12.6
Haynesville	8.0	7.4
Total	21.0	20.0
Completing:		
Appalachia	20.0	17.1
Haynesville	29.0	25.8
Total	49.0	42.9
Drilling & Completing:		
Appalachia	33.0	29.7
Haynesville	37.0	33.2
Total	70.0	62.9

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,		
	2021	2020	2019
Natural Gas			
Production *(Bcf)*:			
Appalachia	883	694	609
Haynesville (1)	132	—	—
Total	1,015	694	609
Average realized gas price, excluding derivatives *($/Mcf)*:			
Appalachia	$ 3.03	$ 1.34	$ 1.98
Haynesville (1)	$ 5.18	$ —	$ —
Total	$ 3.31	$ 1.34	$ 1.98
Average realized gas price, including derivatives *($/Mcf)*:	$ 2.28	$ 1.70	$ 2.18
Oil			
Production *(MBbls)*:			
Appalachia	6,567	5,124	4,673
Haynesville (1)	8	—	—
Other	35	17	23
Total	6,610	5,141	4,696
Average realized oil price, excluding derivatives *($/Bbl)*:			
Appalachia	$ 58.82	$ 29.18	$ 46.86
Haynesville (1)	$ 62.54	$ —	$ —
Other	$ 55.29	$ 37.24	$ 53.66
Total	$ 58.80	$ 29.20	$ 46.90
Average realized oil price, including derivatives *($/Bbl)*:	$ 40.48	$ 46.91	$ 49.56
NGL			
Production *(MBbls)*:			
Appalachia	30,936	25,923	23,611
Other	4	4	9
Total	30,940	25,927	23,620
Average realized NGL price, excluding derivatives *($/Bbl)*:			
Appalachia	$ 28.72	$ 10.24	$ 11.59
Other	$ 40.98	$ 11.50	$ 7.61
Total	$ 28.72	$ 10.24	$ 11.59
Average realized NGL price, including derivatives *($/Bbl)*	$ 18.20	$ 11.15	$ 13.64

(1) The Haynesville E&P assets were acquired through the Indigo Merger in September 2021.

	For the years ended December 31,		
	2021	2020	2019
Total Production by Area *(Bcfe)*			
Appalachia	1,108	880	778
Haynesville [(1)]	132	—	—
Total	1,240	880	778
Total Production by Formation *(Bcfe)*			
Marcellus Shale	943	858	776
Utica Shale	164	22	2
Haynesville Shale [(1)]	100	—	—
Bossier Shale [(1)]	32	—	—
Other	1	—	—
Total	1,240	880	778
Lease Operating Expense			
Cost per Mcfe, excluding ad valorem and severance taxes:			
Appalachia	$ 0.95	$ 0.93	$ 0.92
Haynesville [(1)]	$ 0.88	$ —	$ —
Total	$ 0.95	$ 0.93	$ 0.92

(1) The Haynesville E&P assets were acquired through the Indigo Merger in September 2021.

During 2021, 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. On February 10, 2021, we sold our sand mine to a third party and, as a result, no longer own or operate any mines.

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 NYSE under the symbol “SWN.” On February 25, 2022, the closing price of our common stock was $4.96 and we had 1,990 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 2022 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before May 2, 2022, 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, 2021:

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 2021	—	$ —	n/a	n/a
November 2021	—	$ —	n/a	n/a
December 2021	1,291	$ 5.00	n/a	n/a
Total fourth-quarter 2021:	1,291	$ 5.00	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

None.

ITEM 6. [RESERVED]

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" in this Annual Report. Also, see the risk factors and other cautionary statements described under the heading "Risk Factors" in Item 1A of this Annual Report.

OVERVIEW

Background

We are 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 Appalachian and Haynesville natural gas basins in the lower 48 United States.

E&P. Our primary business is the exploration for and production of natural gas as well as associated NGLs and oil, with our ongoing operations focused on the development of unconventional natural gas reservoirs located in Pennsylvania, West Virginia, Ohio and Louisiana. Our operations in Pennsylvania, West Virginia and Ohio, which we refer to as "Appalachia," are focused on the Marcellus Shale, the Utica and the Upper Devonian unconventional natural gas and liquids reservoirs. Our operations in Louisiana, which we refer to as "Haynesville," are primarily focused on the Haynesville and Bossier natural gas reservoirs. We also have drilling rigs located in Appalachia and Haynesville, and we provide certain oilfield products and services, principally serving our E&P operations through vertical integration. In just over a year, we have completed three strategic acquisitions which have added scale to our operations and have laid the foundation for our future:

- On November 13, 2020, we closed on the Montage Merger, which increased our footprint in West Virginia and Pennsylvania and expanded our operations into Ohio.
- On September 1, 2021, we closed on the Indigo Merger, which established our natural gas operations in the Haynesville and Bossier Shales in Louisiana.
- On December 31, 2021, we closed on the GEPH Merger, which expanded our operations in the Haynesville.

The Indigo Merger and GEPH Merger are the result of our strategy to diversify our operations by expanding our portfolio beyond Appalachia into the Haynesville and Bossier formations, giving us additional exposure to the LNG corridor and other markets on the U.S. Gulf Coast. This expansion lowered our enterprise business risk, expanded our economic inventory, opportunity set and business optionality and enabled immediate cost structure savings. See Note 2 to the consolidated financial statements of this Annual Report for more information on the Mergers.

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 2021. We took several steps in late 2020 and throughout 2021 towards achieving our strategic objectives of increasing scale in our operations, improving our margins, generating free cash flow and reducing our debt leverage metrics. We began the year having completed our first strategic business merger with the acquisition of Montage, which expanded our natural gas and liquids production footprint in Appalachia. During 2021, we completed two additional strategic mergers with the acquisitions of Indigo and GEPH, which diversified our asset portfolio into the Haynesville and Bossier formations of Louisiana with access to the LNG corridor and other U.S. Gulf Coast markets. Recovering commodity prices during 2021 along with the increase in production volumes primarily associated with the Mergers, combined with our continued capital discipline to invest at levels which are designed to maintain our daily production consistent with the end of the prior year, have accelerated the generation of free cash flow. Through our disciplined capital investing, the Mergers have already had, and are expected to continue to have, a positive impact on our business and financial results by producing free cash flow, which we expect to use to pay down debt, resulting in the strengthening of our balance sheet and improvement in our debt leverage metrics.

During 2021, we were also able to successfully finance the Indigo Merger and the GEPH Merger while also reducing our revolver balance and re-financing and extending our debt maturities on a large portion of our near-term senior notes at more favorable interest rates. These financings lowered our overall cost of debt and extended our weighted-average time to maturity.

Generating free cash flow is an important part of our strategy to strengthen our balance sheet, and our long-term goal is to incorporate a cash return component into our overall economic return for shareholders. Our near-term strategic goal is to utilize our free cash flow to reduce our debt, thereby improving our leverage metrics and financial strength. As we approach our target leverage ratio and total debt ranges, we intend to expand our uses of free cash flow to include the return of capital to our shareholders. Free cash flow is a non-GAAP financial measure. We define free cash flow as net cash provided by operating activities, adjusted for (i) changes in assets and liabilities and (ii) cash transaction costs associated with mergers and restructuring, less capital investments. Free cash flow is used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. We believe free cash flow can provide an indicator of excess cash flow available to a company for the repayment of debt or for other general corporate purposes, as it disregards the timing of settlements of operating assets and liabilities.

Natural gas, oil and NGL price fluctuations 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. Although we currently expect to maintain a 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.

Recent Financial and Operating Results

Significant operating and financial highlights for 2021 include:

Total Company

- Completion of the mergers with Indigo on September 1, 2021, and GEPH on December 31, 2021, acquiring 946 producing wells and approximately 256,727 net acres.
- Net loss of $25 million, or ($0.03) per diluted share, improved from a net loss of $3,112 million, or $(5.42) per diluted share, in 2020. Net loss improved as a $5,506 million increase in operating income was partially offset by a $2,660 million reduction resulting from the impact of improved forward pricing on our derivatives position, $806 million of which was unrealized. Excluding the change in derivatives position, the ($2,825) million change in non-cash ceiling test impairments and the ($409) million change in our deferred tax provision recorded 2020, net income increased $2,513 million for 2021, as compared to 2020, primarily as a $2,681 million improvement in operating income was only partially offset by a $128 million change in loss on debt retirement and a $42 million increase in interest expense.
- Operating income was $2,635 million for the year ended December 31, 2021, compared to an operating loss of $2,871 million in 2020. Operating loss in 2020 included $2,825 million in non-cash full cost ceiling impairments. Excluding the non-cash impairments, operating income increased $2,681 million, as increased commodity pricing and natural gas and liquids production were only partially offset by increased operating costs and expenses.
- Net cash provided by operating activities of $1,363 million increased 158% from $528 million in 2020, primarily due to a $2,768 million increase resulting from higher commodity prices, a $524 million increase related to increased production and a $56 million increase in our marketing margin. The increases were partially offset by a $1,854 million decrease in settled derivatives, a $477 million increase in operating costs and expenses, a $132 million decreased impact of working capital and a $42 million increase in interest expense.
- Net cash provided by operating activities, net of changes in working capital, was $1,572 million, a $967 million increase compared to the same period in 2020.
- Total capital invested of $1,108 million increased 23% from $899 million in 2020, as we applied our capital discipline to our recently-acquired natural gas and oil properties, investing at levels designed to keep daily production consistent with the end of the prior year.

E&P

- E&P segment operating income was $2,583 million in 2021, compared to an operating loss of $2,864 million in 2020. E&P segment operating loss in 2020 included $2,825 million in non-cash full cost ceiling impairments. Excluding the non-cash impairments, E&P segment operating income increased $2,622 million from 2020, as improved commodity pricing and higher production volumes more than offset increased operating costs and expenses.

- Year-end reserves of 21,148 Bcfe increased 9,158 Bcfe, or 76%, from 11,990 Bcfe at the end of 2020, as 5,753 Bcfe of acquired reserves, 3,962 Bcfe of additions and 684 Bcfe of positive price and performance revisions were only partially offset by 1,240 Bcfe of production and 1 Bcfe associated with properties that were sold.

- Total net production of 1,240 Bcfe, which was comprised of 82% natural gas, 15% NGLs and 3% oil, increased 41% from 880 Bcfe in 2020. Approximately 80% of this increase came from properties acquired from Montage and Indigo.

- Excluding the effect of derivatives, our realized natural gas price of $3.31 per Mcf, realized oil price of $58.80 per barrel and realized NGL price of $28.72 per barrel increased 147%, 101% and 180%, respectively, from 2020. Our weighted average realized price excluding the effect of derivatives of $3.74 per Mcfe increased 144% from the same period in 2020.

- The E&P segment invested $1,107 million in capital; drilling 87 wells, completing 93 wells and placing 93 wells to sales.

Outlook

Our primary focus in 2022 is to maintain our production profile and improve the safety and efficiency of our operations to optimize our ability to generate free cash flow and further strengthen our balance sheet.

As we develop our core positions in the Appalachian and Haynesville natural gas basins in the U.S., we will concentrate on:

- ***Creating Value.*** We seek to create value for our stakeholders by allocating capital that is focused on earning economic returns; delivering free cash flow; upgrading the quality, depth and capital efficiency of our drilling inventory; and converting resources to proved reserves.

- ***Financial Strength.*** We intend to protect our financial strength by lowering our leverage ratio and total debt; extending the weighted average years to maturity of our debt; lowering our cost of debt; deploying hedges to protect against downward price movement; covering our costs and meeting other financial commitments; and maintaining a strong liquidity position.

- ***Focus on Execution.*** We are focused on operating effectively and efficiently with HSE and ESG as core values; building on our data analytics, operating execution, strategic sourcing, vertical integration and large-scale asset development expertise; further enhancing well performance, optimizing well costs and reducing base production declines; growing margins and securing flow assurance through commercial and marketing arrangements.

- ***Capturing the Tangible Benefits of Scale.*** We strive to create a competitive advantage through strategic transactions that we believe will enhance enterprise returns and deliver financial synergies and operational economies. We believe these transactions lower the risk of our business, expand our opportunity set, increase business optionality and build upon our demonstrated record of asset integration.

We remain committed to achieving these objectives while maintaining our commitment to being environmentally conscious. We believe that we and our industry will continue to face challenges due to evolving environmental standards by both regulators and investors, 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.” As such, we intend to protect our financial strength by reducing our debt while continuing to extend the weighted average years to maturity of our debt, and by maintaining a derivative program designed to reduce our exposure to commodity price volatility.

<u>COVID-19</u>

During 2021, 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, and we continue to monitor its impact on all aspects of our business. The COVID-19 outbreak resulted in state and local governments implementing measures with various levels of stringency to help control the spread of the virus. 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.

Ensuring the health and welfare of our employees, and all who visit our sites, is our top priority, and we are following all U.S. Centers for Disease Control and Prevention and state and local health department guidelines. Further, we implemented infection control measures at all our sites and put in place travel and in-person meeting restrictions and other physical distancing measures. The degree to which the COVID-19 pandemic or any other public health crisis adversely impacts our operations 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 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.

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 year 2021 and fiscal year 2020. For the comparison of fiscal year 2020 and fiscal year 2019, see "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Part II, Item 7 of our 2020 Annual Report on Form 10-K, filed with the Securities and Exchange Commission on March 1, 2021.

E&P

	For the years ended December 31,	
(in millions)	2021	2020
Revenues	$ 4,640 (1)	$ 1,348 (1)
Operating costs and expenses	2,057 (2)	4,212 (3)
Operating income (loss)	$ 2,583	$ (2,864)
Gain (loss) on derivatives, settled	$ (1,492)	$ 362 (4)

(1) Includes $5 million related to gas balancing for the years ended December 31, 2021 and 2020.

(2) Includes $76 million in Merger-related expenses, $7 million of restructuring charges and $6 million of non-cash, non-full cost pool impairments for the year ended December 31, 2021.

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

(4) Includes $11 million amortization of premiums paid related to certain natural gas settled derivatives for the year ended December 31, 2020.

Operating Income

- E&P segment operating income for the year ended December 31, 2021 was $2,583 million compared to an operating loss of $2,864 million for the year ended December 31, 2020. The E&P segment operating loss in 2020 included $2,825 million of non-cash full cost ceiling test impairments. Excluding the non-cash full cost ceiling test impairments in 2020, E&P segment operating income increased $2,622 million for the year ended December 31, 2021, as a 144% improvement in weighted average commodity pricing, excluding derivatives, and a 41% increase in production volumes more than offset a 48% increase in E&P operating costs.

Revenues

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

	For the years ended December 31,			
(in millions except percentages)	Natural Gas	Oil	NGLs	Total
2020 sales revenues (1)	$ 928	$ 150	$ 265	$ 1,343
Changes associated with prices	2,000	196	572	2,768
Changes associated with production volumes	430	43	51	524
2021 sales revenues (1)	**$ 3,358**	**$ 389**	**$ 888**	**$ 4,635**
Increase from 2020	262 %	159 %	235 %	245 %

(1) Excludes $5 million in other operating revenues for the years ended December 31, 2021 and 2020, respectively, related to gas balancing.

Production Volumes

	For the years ended December 31,		
	2021	2020	Increase/ (Decrease)
Natural Gas *(Bcf)*			
Appalachia	883	694	27%
Haynesville [(1)]	132	—	100%
Other	—	—	—%
Total	1,015	694	46%
Oil *(MBbls)*			
Appalachia	6,567	5,124	28%
Haynesville [(1)]	8	—	100%
Other	35	17	106%
Total	6,610	5,141	29%
NGL *(MBbls)*			
Appalachia	30,936	25,923	19%
Other	4	4	—%
Total	30,940	25,927	19%
Production volumes by area *(Bcfe)***:**			
Appalachia	1,108	880	26%
Haynesville [(1)]	132	—	100%
Other	—	—	—%
Total	1,240	880	41%
Total Production by Formation *(Bcfe)*			
Marcellus Shale	943	858	10%
Utica Shale [(2)]	164	22	645%
Haynesville Shale [(1)]	100	—	100%
Bossier Shale [(1)]	32	—	100%
Other	1	—	100%
Total	1,240	880	41%
Production percentage:			
Natural gas	82%	79%	
Oil	3%	4%	
NGL	15%	17%	

(1) The Haynesville E&P assets were acquired through the Indigo Merger in September 2021.

(2) The increase in production from the Utica shale formation was primarily associated with the natural gas and oil properties acquired from the Montage Merger.

- Production volumes for our E&P segment increased 360 Bcfe for the year ended December 31, 2021, compared to the same period in 2020, primarily due the recent acquisitions of producing natural gas and oil properties in Appalachia from Montage in November 2020 and the Haynesville from Indigo in September 2021. Production from these properties accounted for 80% of the increase in production volumes in 2021, as compared to 2020.
- Oil and NGL production increased 29% and 19%, respectively, for the year ended December 31, 2021, compared to 2020, primarily due to our increased activities in Appalachia, as we moved to take advantage of favorable liquids pricing.

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 derivative 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,		
	2021	2020	Increase/ (Decrease)
Natural Gas Price:			
NYMEX Henry Hub Price *($/MMBtu)* [(1)]	$ 3.84	$ 2.08	85%
Discount to NYMEX [(2)]	(0.53)	(0.74)	(28)%
Average realized gas price, excluding derivatives *($/Mcf)*	$ 3.31	$ 1.34	147%
Gain on settled financial basis derivatives *($/Mcf)*	0.09	0.11	
Gain (loss) on settled commodity derivatives *($/Mcf)*	(1.12)	0.25	
Average realized gas price, including derivatives *($/Mcf)*	$ 2.28	$ 1.70	34%
Oil Price:			
WTI oil price *($/Bbl)* [(3)]	$ 67.92	$ 39.40	72%
Discount to WTI [(4)]	(9.12)	(10.20)	(11)%
Average oil price, excluding derivatives *($/Bbl)*	$ 58.80	$ 29.20	101%
Gain (loss) on settled derivatives *($/Bbl)*	(18.32)	17.71	
Average oil price, including derivatives *($/Bbl)*	$ 40.48	$ 46.91	(14)%
NGL Price:			
Average realized NGL price, excluding derivatives *($/Bbl)*	$ 28.72	$ 10.24	180%
Gain (loss) on settled derivatives *($/Bbl)*	(10.52)	0.91	
Average realized NGL price, including derivatives *($/Bbl)*	$ 18.20	$ 11.15	63%
Percentage of WTI, excluding derivatives	42%	26%	
Total Weighted Average Realized Price:			
Excluding derivatives *($/Mcfe)*	$ 3.74	$ 1.53	144%
Including derivatives *($/Mcfe)*	$ 2.53	$ 1.94	30%

(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.

(3) Based on the average daily settlement price of the nearby month futures contract over the period.

(4) This discount primarily includes location and quality adjustments.

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 the risk factor “Our commodity price risk management and measurement systems and economic hedging activities might not be effective and could increase the volatility of our results” included in Item 1A in this Annual Report for additional discussion about our derivatives and risk management activities.

The tables below present the amount of our future natural gas production in which the impact of basis volatility has been limited through derivatives and physical sales arrangements as of December 31, 2021:

	Volume *(Bcf)*	Basis Differential
Basis Swaps – Natural Gas		
2022	322	$ (0.38)
2023	200	(0.45)
2024	46	(0.71)
2025	9	(0.64)
Total	577	
Physical NYMEX Sales Arrangements – Natural Gas [(1)]		
2022	645	$ (0.11)
2023	521	(0.08)
2024	389	(0.06)
2025	308	(0.04)
2026	134	0.00
2027	125	0.01
2028	125	0.01
2029	125	0.01
2030	47	0.00
Total	2,419	

(1) Physical sales volumes are presented on a gross basis.

In addition to protecting basis, the table below presents the amount of our future production in which price is financially protected through derivatives as of December 31, 2021:

	2022	2023	2024
Natural gas *(Bcf)*	1,297	923	279
Oil *(MBbls)*	4,583	2,114	54
Ethane *(MBbls)*	5,932	432	—
Propane *(MBbls)*	6,674	518	—
Normal butane *(MBbls)*	1,587	164	—
Natural gasoline *(MBbls)*	1,840	157	—
Total financial protection on future production *(Bcfe)*	1,421	943	279

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)	2021	2020	Increase/ (Decrease)
Lease operating expenses	$ 1,175	$ 815	44%
General & administrative expenses	124	108	15%
Merger-related expenses	76	41	85%
Restructuring charges	7	16	(56)%
Taxes, other than income taxes	132	54	144%
Full cost pool amortization	521	333	56%
Non-full cost pool DD&A	16	15	7%
Impairments	6	2,830	(100)%
Total operating costs	$ 2,057	$ 4,212	(51)%

Average unit costs per Mcfe:	For the years ended December 31, 2021	2020	Increase/ (Decrease)
Lease operating expenses [1]	$ 0.95	$ 0.93	2%
General & administrative expenses	$ 0.10 [2]	$ 0.12 [3]	(17)%
Taxes, other than income taxes	$ 0.11	$ 0.06	83%
Full cost pool amortization	$ 0.42	$ 0.38	11%

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

(2) Excludes $76 million in merger-related expenses and $7 million in restructuring charges for the year ended December 31, 2021.

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

Lease Operating Expenses

- Lease operating expenses per Mcfe increased $0.02 for the year ended December 31, 2021, compared to 2020, primarily due to increases in liquids production, which includes processing fees, fuel and electricity costs and natural gas treating costs.

General and Administrative Expenses

- General and administrative expenses increased $16 million for the year ended December 31, 2021, compared to 2020, primarily due to increased personnel costs associated with our expanded operations in Appalachia and the Haynesville.

- On a per Mcfe basis, excluding merger-related expenses, restructuring charges and legal settlement charges, general and administrative expenses per Mcfe decreased by $0.02 for the year ended December 31, 2021, compared to 2020, as a 41% increase in production volumes more than offset a 16% increase in expenses.

Merger-Related Expenses

- Beginning with the Montage Merger in November 2020, we have focused on building scale and geographic diversification throughout 2021. As a result of this strategy, we merged with Indigo in September 2021 and GEPH on December 31, 2021. The table below presents the charges incurred for our merger-related activities for the years ended December 31, 2021 and 2020:

	For the years ended December 31, 2021				2020
(in millions)	Indigo Merger	GEPH Merger	Montage Merger	**Total**	Montage Merger
Professional fees (bank, legal, consulting)	$ 27	$ 19	$ 1	**$ 47**	$ 18
Representation & warranty insurance	4	7	—	**11**	—
Contract buyouts, terminations and transfers	7	1	—	**8**	5
Due diligence and environmental	3	1	—	**4**	—
Employee-related	2	—	1	**3**	17
Other	2	—	1	**3**	1
Total merger-related expenses	$ 45	$ 28	$ 3	**$ 76**	$ 41

We refer you to Note 2 of the consolidated financial statements included in this Annual Report for additional details about the Mergers.

Restructuring Charges

- In February 2021, employees were notified of a workforce reduction plan as part of an ongoing strategic effort to reposition our portfolio, optimize operational performance and improve margins. 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, 2021, and were substantially complete by the end of the first quarter of 2021. For the year ended December 31, 2021, we recognized a total restructuring expense of $7 million primarily related to cash severance, including payroll taxes.

- 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.

See Note 3 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 increased $0.05 per Mcfe for the year ended December 31, 2021, compared to the same period in 2020, primarily due to the impact of higher commodity pricing on our severance taxes in West Virginia, which are calculated as a fixed percentage of revenue net of allowable production expenses, and the impact of incremental severance and ad valorem taxes associated with our acquired assets in Louisiana.

Full Cost Pool Amortization

- Our full cost pool amortization rate increased $0.04 per Mcfe for the year ended December 31, 2021, as compared to 2020. The average amortization rate increased primarily as a result of the impact of our acquisitions of natural gas and oil properties in Appalachia and the Haynesville.
- 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 $2,231 million at December 31, 2021 compared to $1,472 million at December 31, 2020. The unevaluated costs excluded from amortization increased by $759 million, as compared to 2020, as the evaluation of previously unevaluated properties totaling $532 million in 2021 was more than offset by the impact of $1,291 million of unevaluated capital invested. Of the total increase, $743 million related to the Haynesville properties acquired during 2021.
- No impairment expense was recorded in 2020 or 2021 in relation to our natural gas and oil properties acquired from Montage. These properties were recorded at fair value as of November 13, 2020, in accordance with ASC Topic 820 – *Fair Value Measurement*. In the fourth quarter of 2020, pursuant to SEC guidance, we determined that the fair value of the properties acquired at the closing of the Montage 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 Montage 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 could continue to demonstrate that the fair value of properties acquired clearly exceeded the full cost ceiling limitation beyond a reasonable doubt in each reporting period. As part of the waiver received from the SEC, we were 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 Montage Merger was based on future commodity market pricing for natural gas and oil pricing existing at the date of the Montage Merger, and we affirmed that there has not been a material decline to the fair value of these acquired assets since the Montage Merger. The properties acquired in the Montage Merger had 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. Due to the improvement in commodity prices during 2021, no impairment charge would have been recorded in 2021 had the Montage natural gas and oil properties been included in the full cost ceiling test.

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 a $6 million impairment to non-core E&P assets for the year ended December 31, 2021.

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

Marketing

	For the years ended December 31,		
(in millions except percentages)	2021	2020	Increase/ (Decrease)
Marketing revenues	$ 6,186	$ 2,145	188%
Other operating revenues	3	—	100%
Marketing purchases	6,114	2,129	187%
Operating costs and expenses	23	23	—%
Operating income (loss)	$ 52	$ (7)	843%
Volumes marketed *(Bcfe)*	1,542	1,138	36%
Percent natural gas production marketed from affiliated E&P operations	95%	89%	
Affiliated E&P oil and NGL production marketed	82%	81%	

Operating Income (Loss)

- Marketing operating income increased $59 million for the year ended December 31, 2021, compared to 2020, primarily due to a $56 million increase in the marketing margin as well as a $1 million increase in gas storage gains and $2 million in non-performance damages received, both recorded in other operating revenues. Operating costs and expenses remained flat over the periods presented.
- The margin generated from marketing activities increased $56 million for the year ended December 31, 2021, as compared to the prior year, primarily due to a 36% increase in volumes marketed and a corresponding reduction in third-party purchases and sales, which were used in 2020 to optimize our transportation folio, due to increased affiliated volumes available for marketing.

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 increased $4,041 million for the year ended December 31, 2021, compared to 2020, primarily due to a 113% increase in the price received for volumes marketed and a 404 Bcfe increase in the volumes marketed.

Operating Costs and Expenses

- Marketing operating costs and expenses remained flat for the year ended December 31, 2021, compared to the year ended December 31, 2020, primarily due to continued efforts to control costs.

Consolidated

Interest Expense

(in millions except percentages)	For the years ended December 31, 2021	2020	Increase/ (Decrease)
Gross interest expense:			
Senior notes	$ 190	$ 155	23%
Credit arrangements	30	16	88%
Amortization of debt costs	13	11	18%
Total gross interest expense	233	182	28%
Less: capitalization	(97)	(88)	10%
Net interest expense	$ 136	$ 94	45%

- Interest expense related to our senior notes increased for the year ended December 31, 2021, as compared to 2020, as the interest savings from the repurchase of $1,091 million of our outstanding senior notes in 2021 was offset by the interest associated with the August 2021 public offering of $1,200 million aggregate principal amount of our 5.375% Senior Notes due 2030 and the September 2021 assumption of Indigo Notes, which were exchanged for $700 million aggregate principal amount of our 5.375% Senior Notes due 2029 related to the Indigo Merger. In late December 2021, we issued $1,150 million aggregate principal amount of our 4.75% Senior Notes due 2032 and $550 million of Term Loan financing, subject to a variable interest rate of 3% at December 31, 2021, each of which will have the effect of increasing our gross interest expense in 2022.

- We capitalize interest associated with the cost of acquiring and assessing our unevaluated natural gas and oil properties. Capitalized interest increased $9 million for the year ended December 31, 2021, compared to 2020, as the acquisition of unevaluated Haynesville natural gas and oil properties on September 1, 2021 outpaced the evaluation of our existing unevaluated natural gas and oil properties over the past twelve months. The impact of the addition of unevaluated Haynesville properties from the Indigo Merger and the GEPH Merger is expected to increase the amount of capitalized interest until such time as they are evaluated.

- Capitalized interest decreased as a percentage of gross interest expense for the year ended December 31, 2021, as compared to 2020, primarily as a result of the smaller percentage change in the unevaluated natural gas and oil properties for most of 2021, prior to the acquisitions of the Haynesville unevaluated natural gas and oil properties, as compared to the larger increase in gross interest expense during 2021, associated with increased debt levels as a result of the Montage Merger and the Indigo Merger over the same period.

We refer you to Note 9 to the consolidated financial statements included in this Annual Report for additional details about our debt and our financing activities.

Gain (Loss) on Derivatives

(in millions)	For the years ended December 31, 2021	2020
Loss on unsettled derivatives	$ (945)	$ (139)
Gain (loss) on settled derivatives	(1,492)	362
Non-performance risk adjustment	1	1
Total gain (loss) on derivatives	$ (2,436)	$ 224

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

- For the year ended December 31, 2021, we recorded a loss on early extinguishment of debt of $93 million as a result of our repurchase of $1,091 million in aggregate principal amount of our outstanding senior notes for $1,177 million in cash, including premiums and fees, and the write-off of $7 million in related unamortized debt discounts and issuance costs.

- 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. 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, 2021	2020
Income tax expense (benefit)	$ —	$ 407
Effective tax rate	0 %	(15)%

- In 2020, due to significant pricing declines and the material write-down of the carrying value of our natural gas and oil properties in addition to other negative evidence, management concluded that it was more likely than not that a portion of our deferred tax assets would not be realized and recorded a valuation allowance. As of December 31, 2021, we still maintain a full valuation allowance. We also retained a valuation allowance of $59 million related to net operating losses in jurisdictions in which we no longer operate. 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.
- Due to the issuance of common stock associated with the Indigo Merger, as discussed in Note 2 to the consolidated financial statements to this Annual Report, we incurred a cumulative ownership change and as such, our net operating losses ("NOLs") prior to the acquisition are subject to an annual limitation under Internal Revenue Code Section 382 of approximately $48 million. The ownership changes and resulting annual limitation will result in the expiration of NOLs or other tax attributes otherwise available, with a corresponding decrease in our valuation allowance. At December 31, 2021, we had approximately $4 billion of federal NOL carryovers, of which approximately $3 billion have an expiration date between 2035 and 2037 and $1 billion have an indefinite carryforward life. We currently estimate that approximately $2 billion of these federal NOLs will expire before they are able to be used. The non-expiring NOLs remain subject to a full valuation allowance. If a subsequent ownership change were to occur as a result of future transactions in our common stock, our use of remaining U.S. tax attributes may be further limited.

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 2021, the banks participating in our 2018 credit facility reaffirmed our elected borrowing base and aggregate commitments to be $2.0 billion. At December 31, 2021, we had approximately $1.4 billion of total available liquidity, which exceeds our currently modeled needs as we remain committed to our strategy of capital discipline.

In November 2021 in conjunction with the GEPH Merger, we amended our 2018 credit facility agreement to permit access to additional secured debt capacity in the form of a term loan for incremental capital up to $900 million, ranking equally with our 2018 credit facility. In December 2021, we raised $550 million in term loan financing to partially fund the GEPH Merger, with no impact to our liquidity at year end. The remaining $350 million of incremental term loan capacity remains accessible through November 2022 and provides access to another secured debt capital source for liquidity purposes.

Our flexibility to access incremental secured debt capital is derived from our excess asset collateral value above the elected $2.0 billion borrowing base and aggregate commitments of our 2018 credit facility. Our ability to issue secured debt is governed by the limitations of our 2018 credit facility as well as our secured debt capacity (as defined by our senior note indentures) which was $3.7 billion as of December 31, 2021, based on 25% of adjusted consolidated net tangible assets.

Looking forward in 2022, we expect to continue to generate free cash flow from operations, net of changes in working capital, in excess of our expected capital investments, and we intend to utilize this free cash flow to pay down our debt. 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. Although we are continually adding additional derivative positions for portions of our expected 2022, 2023 and 2024 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 entered into a 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 2021, the banks participating in our 2018 credit facility reaffirmed the elected borrowing base to be $2.0 billion, which also reflected our aggregate commitments. The borrowing base is subject to redetermination at least twice a year, which typically occurs 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. 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, 2021, we had $460 million of borrowings on our 2018 credit facility and $160 million in outstanding letters of credit. We currently do not anticipate being required to supply a materially greater amount of letters of credit under our existing contracts. We refer you to Note 9 to the consolidated financial statements included in this Annual Report for additional discussion of our 2018 credit facility.

As of December 31, 2021, we were in compliance with all of the applicable covenants contained in the credit agreement governing our 2018 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 credit facility.

The credit status of the financial institutions participating in our 2018 credit facility could adversely impact our ability to borrow funds under the 2018 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 2018 credit facility.

Our exposure to the anticipated transition from LIBOR is limited to the 2018 credit facility. The USD-LIBOR settings are expected to be published through June 2023, and we anticipate using a variation of this rate until the underlying agreements are extended beyond the LIBOR publication date.

Key financing activities for the years ended December 31, 2021 and 2020 are as follows:

Debt and Common Stock Issuance

- On December 22, 2021, we completed a public offering of $1,150 million aggregate principal amount of our 4.75% Senior Notes due 2032 (the "2032 Notes"), with net proceeds from the offering totaling $1,133 million after underwriting discounts and offering expenses. The net proceeds were used to fund a portion of the GEPH Merger, which closed on December 31, 2021, and to fund tender offers for $300 million of our 2025 Notes. The remaining proceeds were used for general corporate purposes.

- In contemplation of the GEPH Merger, on December 22, 2021, we entered into a term loan credit agreement with a group of lenders that provided for a $550 million secured term loan facility which matures on June 22, 2027 (the "Term Loan"). As of December 31, 2021, we had borrowings under the Term Loan of $550 million. The net proceeds from the initial loans of $542 million were used to fund a portion of the GEPH Merger on December 31, 2021.

- On December 31, 2021, we issued 99,337,748 shares of our common stock in conjunction with the GEPH Merger. These shares of our common stock had an aggregate dollar value equal to approximately $463 million, based on the closing price of $4.66 per share of our common stock on the NYSE on December 31, 2021. See Note 2 for additional details on the GEPH Merger.

- In November 2021, in contemplation of the GEPH Merger, we amended our 2018 credit facility agreement to permit access to additional secured debt capacity in the form of the previously-described Term Loan for incremental capital up to $900 million, ranking equally with our 2018 credit facility. As of December 31, 2021, we had borrowings under the Term Loan of $550 million, which were used to partially fund the GEPH Merger, and $350 million of incremental term loan capacity, which remains accessible through November 2022.

- In August 2021, we completed a public offering of $1,200 million aggregate principal amount of our 5.375% Senior Notes due 2030 (the "2030 Notes"), with net proceeds from the offering totaling $1,183 million after underwriting discounts and offering expenses. The proceeds were used to repurchase the $791 million principal amount of certain of our outstanding senior notes. The remaining proceeds were used to pay borrowings under our 2018 credit facility and for general corporate purposes, including consideration for the Indigo Merger.

- In September 2021, we issued 337,827,171 shares of our common stock in conjunction with the Indigo Merger. These shares of our common stock had an aggregate dollar value equal to approximately $1,588 million, based on the closing price of $4.70 per share of our common stock on the NYSE on September 1, 2021. See Note 2 for additional details on the Indigo Merger.

- In conjunction with the Indigo Merger and pursuant to the terms of the merger agreement, in September 2021, we assumed $700 million in aggregate principal amount of Indigo's 5.375% Senior Notes due 2029 (the "Indigo Notes"). Subsequent to the Indigo Merger, we exchanged the Indigo Notes for approximately $700 million of newly issued 5.375% Senior Notes due 2029.

- In November 2020, we issued 69,740,848 shares of our common stock in conjunction with the Montage Merger. These shares of our common stock had an aggregate dollar value equal to approximately $213 million, based on the closing price of $3.05 per share of our common stock on the NYSE on November 13, 2020. See Note 2 for additional details on the Montage Merger.

- 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. The net proceeds were used to fund a portion of the Montage Merger in November 2020.

- 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 2018 credit facility were used to fund a redemption of $510 million aggregate principal amount of Montage's senior notes in connection with the closing of the Montage Merger.

<u>Debt Repurchases</u>

- In 2021, we repurchased $6 million of our 4.10 % Senior Notes due 2022, $467 million of our 4.95% Senior Notes due 2025 and $618 million of our 7.50% Senior Notes due 2026 for $1,177 million in cash, including premiums and fees, and we recognized an additional $7 million in unamortized debt expenses, resulting in a loss on early extinguishment of debt of $93 million.

- 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. We refer you to Note 9 to the consolidated financial statements included in this Annual Report for additional discussion of our senior notes.

In January 2022, we repurchased the remaining outstanding principal balance of $201 million on our 2022 Senior Notes using our 2018 credit facility. As a result of the focused work on refinancing and repayment of our debt in recent years, our outstanding revolver balance and $16 million of our Term Loan principal are the only debt balances scheduled to become due prior to 2025.

At February 25, 2022, we had long-term debt issuer ratings of Ba2 by Moody's (rating and stable outlook affirmed on November 29, 2021), BB+ by S&P (rating upgraded to BB+ with stable outlook on January 6, 2022) and BB by Fitch Ratings (rating and stable outlook affirmed on November 29, 2021). Effective in July 2018, the interest rate for our 2025 Notes was 6.20%, reflecting a net downgrade in our bond ratings since their issuance. 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, with the first coupon payment at the higher interest rate in January 2021. On September 1, 2021, S&P upgraded our bond rating to BB, and on January 6, 2022, S&P further upgraded our bond rating to BB+, which will have the effect of decreasing the interest rate on the 2025 Notes to 5.95%, beginning with coupon payments after January 2022. 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)	2021	2020
Net cash provided by operating activities	$ 1,363	$ 528
Net cash used in investing activities	(2,604)	(881)
Net cash provided by financing activities	1,256	361

Cash Flow from Operations

	For the years ended December 31,	
(in millions)	2021	2020
Net cash provided by operating activities	$ 1,363	$ 528
Add back (subtract): changes in working capital	209	77
Net cash provided by operating activities, net of changes in working capital	$ 1,572	$ 605

- Net cash provided by operating activities increased 158% or $835 million for the year ended December 31, 2021, compared to the same period in 2020, primarily due to a $2,768 million increase resulting from higher commodity prices, a $524 million increase related to increased production and a $56 million increase in our marketing margin. The increases were partially offset by a $1,854 million decrease in settled derivatives, a $477 million increase in operating costs and expenses, a $132 million decreased impact of working capital and a $42 million increase in interest expense.

- Net cash generated from operating activities, net of changes in working capital, exceeded our capital investments by $464 million for the year ended December 31, 2021, compared to providing 67% of our cash requirements for capital investments for the same period in 2020.

Cash Flow from Investing Activities

- Total E&P capital investing increased $208 million for the year ended December 31, 2021, compared to the same period in 2020, due to a $191 million increase in direct E&P capital investing, an $8 million increase in capitalized internal costs and a $9 million increase in capitalized interest.

- Capitalized interest increased for the year ended December 31, 2021, as compared to the same period in 2020, as the acquisition of Haynesville unevaluated natural gas and oil properties on September 1, 2021 outpaced the evaluation of our existing unevaluated natural gas and oil properties over the past twelve months. The impact of the addition of additional Haynesville properties from the GEPH Merger on December 31, 2021 is expected to increase the amount of capitalized interest until such time as it is evaluated.

- Cash paid in mergers includes cash consideration of $373 million and $1,269 million paid for the Indigo Merger and GEPH Merger, respectively.

(in millions)	For the years ended December 31, 2021	2020
Additions to properties and equipment	$ 1,032	$ 896
Adjustments for capital investments:		
Changes in capital accruals	70	(3)
Other [1]	6	6
Total capital investing	$ 1,108	$ 899

(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, 2021	2020	Increase/ (Decrease)
E&P capital investing	$ 1,107	$ 899	
Other capital investing [1]	1	—	
Total capital investing	$ 1,108	$ 899	23%

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

(in millions)	For the years ended December 31, 2021	2020
E&P Capital Investments by Type:		
Exploratory and development, including workovers	$ 886	$ 692
Acquisition of properties [2]	43	37
Water infrastructure project	5	9
Other	12	17
Capitalized interest and expenses	161	144
Total E&P capital investments	$ 1,107	$ 899
E&P Capital Investments by Area		
Appalachia	$ 882	$ 872
Haynesville	200	—
Other E&P [1]	25	27
Total E&P capital investments	$ 1,107	$ 899

(1) Includes $5 million and $9 million for the years ended December 31, 2021 and 2020, respectively, related to water infrastructure.

(2) Excludes the impact of $1,269 million and $373 million paid for the GEPH Merger and Indigo Merger, respectively.

	For the years ended December 31, 2021	2020
Gross Operated Well Count Summary:		
Drilled	87	98
Completed	93	96
Wells to sales	93	100

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, 2021 was $1,256 million, compared to net cash provided by financing activities of $361 million for the same period in 2020.
- In December 2021, we completed a public offering of $1,150 million aggregate principal amount of our 2032 Notes, with net proceeds from the offering totaling $1,133 million after underwriting discounts and offering expenses. The net proceeds were used to fund a portion of the GEPH Merger, which closed on December 31, 2021, and to repurchase $300 million of our 2025 Notes. The remaining proceeds were used for general corporate purposes.

- In December 2021, we entered into our secured Term Loan facility and, as of December 31, 2021, had borrowings of $550 million outstanding. The net proceeds from the initial loans of $542 million were used to fund a portion of the GEPH Merger on December 31, 2021.
- In December 2021, we repaid the outstanding balance of $81 million related to GEPH's revolving credit facility.
- In September 2021, we repaid the outstanding balance of $95 million related to Indigo's revolving credit facility.
- In August 2021, we completed a public offering of $1,200 million aggregate principal amount of our 2030 Notes, with net proceeds from the offering totaling $1,183 million after underwriting discounts and offering expenses. The net proceeds were used to repurchase the $791 million principal amount of certain of our outstanding senior notes. The remaining proceeds were used to pay borrowings under our 2018 credit facility and for general corporate purposes, including consideration for the Indigo Merger.
- 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 August 2020, we completed an underwritten 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.
- 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.

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 $1,639 million at December 31, 2021, a $1,298 million decrease from December 31, 2020, as a $792 million increase in accounts receivable and a $15 million increase in cash were more than offset by $1,092 million reduction in the current mark-to-market value of our derivatives position related to improved forward pricing across all commodities, along with a $745 million increase in various payables and the reclassification of long-term debt to short-term debt of $206 million. Additionally, other current liabilities at December 31, 2021 increased $55 million, compared to December 31, 2020, primarily due to the assumption of $47 million in liabilities related to the Indigo Merger and $8 million in prepayments/collateral received from certain customers. 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, 2021, our material off-balance sheet arrangements and transactions include operating service arrangements and $160 million in letters of credit outstanding against our 2018 credit facility. 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, 2021, 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)	**$ 10,456**	$ 1,144	$ 2,046	$ 1,894	$ 2,416	$ 2,956
Debt	**5,440**	206	471	400	2,013	2,350
Interest on debt (2)	**2,037**	262	543	484	552	196
Operating leases (3)	**187**	38	61	49	38	1
Compression services (4)	**39**	24	14	1	—	—
Operating agreements	**89**	54	18	12	5	—
Purchase obligations	**64**	64	—	—	—	—
Other obligations (5)	**10**	7	3	—	—	—
	$ 18,322	$ 1,799	$ 3,156	$ 2,840	$ 5,024	$ 5,503

(1) As of December 31, 2021, 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 \$10.5 billion, \$872 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 \$869 million.

Prior to the Indigo Merger, in May 2021, Indigo closed on an agreement to divest its Cotton Valley natural gas and oil properties. Indigo retained certain contractual commitments related to volume commitments associated with natural gas gathering, for which Southwestern will assume the obligation to pay the gathering provider for any unused portion of the volume commitment under the agreement through 2027, depending on the buyer's actual use. As of December 31, 2021, up to approximately \$36 million of these contractual commitments remain (included in the table above), and the Company has recorded a \$17 million liability for its portion of the estimated future payments.

Includes firm transportation commitments acquired with the Montage Merger totaling approximately \$976 million. These commitments approximate \$96 million within the next year, \$192 million from 1 to 3 years, \$189 million from 3 to 5 years, \$270 million from 5 to 8 years and \$229 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, with \$327 million in total contractual commitments remaining of which the seller has agreed to reimburse \$100 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, 2021. Senior note interest rates were based on our credit ratings as of December 31, 2021.

(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, 2021, our E&P segment had commitments of approximately \$38 million for compression services associated primarily with our Appalachia division.

(5) Our other significant contractual obligations include approximately \$10 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 closing of the Mergers, discussed further in Note 2 to the consolidated financials included in this Annual Report, certain acquired 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. Prices used to calculate the ceiling value of reserves were as follows:

	December 31, 2021	December 31, 2020
Natural gas *(per MMBtu)*	**$ 3.60**	$ 1.98
Oil *(per Bbl)*	**$ 66.56**	$ 39.57
NGLs *(per Bbl)*	**$ 28.65**	$ 10.27

Using the average quoted prices above, adjusted for market differentials, our net book value of our United States natural gas and oil properties did not exceed the ceiling amount at December 31, 2021. We had no derivative positions that were designated for hedge accounting as of December 31, 2021. 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 future non-cash impairments to our natural gas and oil properties.

The net book value of our natural gas and oil properties exceeded the ceiling amount in each quarter of 2020 resulting in a total non-cash full cost ceiling test impairment of $2,825 million. We had no derivative positions that were designated for hedge accounting as of December 31, 2020.

No impairment expense was recorded in 2020 or 2021 in relation to our natural gas and oil properties acquired from Montage. These properties were recorded at fair value as of November 13, 2020, in accordance with ASC Topic 820 – *Fair Value Measurement*. In the fourth quarter of 2020, pursuant to SEC guidance, we determined that the fair value of the properties acquired at the closing of the Montage 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 Montage 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 could continue to demonstrate that the fair value of properties acquired clearly exceeded the full cost ceiling limitation beyond a reasonable doubt in each reporting period. As part of the waiver received from the SEC, we were 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 Montage Merger was based on future commodity market pricing for natural gas and oil pricing existing at the date of the Montage Merger, and we affirmed that there has not been a material decline to the fair value of these acquired assets since the Montage Merger. The properties acquired in the Montage Merger had 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. Due to the improvement in commodity prices during 2021, no impairment charge would have been recorded in 2021 had the Montage natural gas and oil properties been included in the full cost ceiling test.

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, 2021 was approximately 82% natural gas, 2% NGLs and 16% oil, and our standardized measure and reserve quantities as of December 31, 2021, were $18.73 billion and 21.1 Tcfe, respectively.

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, 2021, we had approximately $2,231 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.

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 27 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 33 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 24 years and over 20 years of practical experience in petroleum geosciences and petroleum engineering, respectively; (2) have over 13 years and over 20 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 54% of our total reserve base as of December 31, 2021. 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 all operated proved developed properties plus all proved undeveloped locations. The proved developed properties included in the NSAI audit account for approximately 99% of the proved developed reserve volume and 99% of the proved developed present worth as of December 31, 2021. The proved undeveloped properties included in the NSAI audit account for 100% of the proved undeveloped reserve volume and 100% of the proved undeveloped present worth as of December 31, 2021. 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 January 28, 2022, NSAI issued its audit opinion as to the reasonableness of our reserve estimates for the year-ended December 31, 2021 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 as this is an indication of the amount that 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 Mergers qualified as business combinations, and as such, we estimated the fair values of the assets acquired and liabilities assumed as of respective acquisition dates. 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 discounted cash flow models and we 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 on November 13, 2020 of approximately $213 million.
- We recorded the net assets acquired and liabilities assumed in the Indigo Merger at their estimated fair value on September 1, 2021 of approximately $1,961 million.
- We recorded the net assets acquired and liabilities assumed in the GEPH Merger at their estimated fair value on December 31, 2021 of approximately $1,732 million.

We consider the estimated fair values above to be representative of the prices paid by typical market participants. These measurements resulted in no goodwill or bargain purchases 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 both 2021 and 2020, we financially protected 83% 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, 2021, 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, 2021.

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

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. We have commenced the pension plan termination process, but the specific date for the completion of the process is unknown at this time and will depend on certain legal and regulatory requirements or approvals. As part of the termination process, we expect to distribute lump sum payments to or purchase annuities for the benefit of plan participants, which is dependent on the participants' elections. In addition, we expect to make a payment equal to the difference between the total benefits due under the plan and the total value of the assets available, which, as of December 31, 2021, was approximately $12 million. Our current funding policy is to continue to contribute amounts which are actuarially determined to provide the plan with sufficient assets to meet future benefit payment requirements and which are tax deductible. We are in the process of evaluating the impact of the termination and future settlement accounting on our consolidated financial statements and related disclosures.

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, 2021 benefit obligation the initial discount rate assumed is 3.20%. This compares to an initial discount rate of 3.10% for the benefit obligation and periodic benefit cost recorded in 2021. For the 2022 periodic benefit cost, the expected return assumed was reduced from 5.10% to 0.10%, as the investment allocations have shifted from a balanced portfolio to short-term fixed-income assets in alignment with the plan termination process. Using the assumed rates discussed above, we recorded total benefit cost of $4 million in 2021 related to our pension and other postretirement benefit plans, which included a $2 million settlement adjustment.

As of December 31, 2021, we recognized a liability of $25 million, compared to $46 million at December 31, 2020, related to our pension and other postretirement benefit plans. During 2021, we made cash contributions totaling $12 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 2021 and 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.

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, 2021, one purchaser accounted for 12% of our revenues. If we had completed the Indigo Merger and the GEPH Merger at the beginning of 2021, this same purchaser would have accounted for approximately 16% of our revenues. A default on this account could have a material impact on the Company. For the year ended December 31, 2020, one purchaser accounted for 10% of our revenues. See "Commodities Risk" below for discussion of credit risk associated with commodities trading.

Interest Rate Risk

As of December 31, 2021, we had approximately $4.4 billion of outstanding senior notes with a weighted average interest rate of 5.68%, $550 million of borrowings under our Term Loan facility and $460 million of borrowings under our 2018 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, 2021, we had long-term debt issuer ratings of Ba2 by Moody's, BB by S&P and BB by Fitch Ratings. On September 1, 2021, S&P upgraded our bond rating to BB, and on January 6, 2022, S&P further upgraded our bond rating to BB+, which will have the effect of decreasing the interest rate on the 2025 notes to 5.95%, beginning with coupon payments paid after January 2022. 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)	2022	2023	2024	2025	2026	Thereafter	**Total**
Fixed rate payments [1]	$ 201	$ —	$ —	$ 389	$ —	$ 3,840	**$ 4,430**
Weighted average interest rate	4.10 %	— %	— %	5.95 %	— %	5.73 %	**5.68 %** [2]
Variable rate payments [1]	$ 5	$ 6	$ 465	$ 6	$ 5	$ 523	**$ 1,010**
Weighted average interest rate	3.00 %	3.00 %	2.09 %	3.00 %	3.00 %	3.00 %	**2.58 %**

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

(2) Outstanding senior notes weighted average interest rate includes the benefit of S&P upgrades from BB- to BB+, resulting in an improvement of the 2025 senior notes' interest rate from 6.45% to 5.95%, beginning with coupon payments paid after January 2022.

Commodities Risk

We use 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, 2021, 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, 2021.

The effectiveness of our internal control over financial reporting as of December 31, 2021 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, 2021 and 2020, 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, 2021, 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, 2021, 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, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021 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, 2021, 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.

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

As described in Note 1 to the consolidated financial statements, the Company's consolidated natural gas and oil properties balance was $33,631 million as of December 31, 2021, and depreciation, depletion and amortization expense for the year ended December 31, 2021 was $546 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 natural gas liquids (NGL) reserves. 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%. 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 "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 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 and its specialists in developing the estimates of proved natural gas, oil and NGL reserves and the assumption applied to the full cost ceiling test 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 full cost ceiling 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, 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 specialists, tests of the completeness and accuracy of the data used by the specialists, and an evaluation of specialists' findings.

Acquisitions of Indigo Natural Resources LLC and GEP Haynesville, LLC – Valuation of Proved Natural Gas and Oil Properties

As described in Note 2 to the consolidated financial statements, the Company completed the acquisitions of Indigo Natural Resources LLC and GEP Haynesville, LLC for net consideration of $1,961 million and $1,732 million, respectively, which resulted in $4,507 million of proved natural gas and oil properties being recorded from these acquisitions. 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. The most significant assumptions relate to the estimated fair values of proved natural gas and oil 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 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 “specialists”).

The principal considerations for our determination that performing procedures relating to the valuation of proved natural gas and oil properties from the acquisitions of Indigo Natural Resources LLC and GEP Haynesville, LLC is a critical audit matter are (i) the significant judgment by management, including the use of management’s specialists, when developing the fair value of acquired proved natural gas and oil properties, which in turn led to (ii) a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating management’s significant assumptions related to future production volumes, future commodity prices, and the weighted average cost of capital rate; 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) reading the purchase agreement; (ii) testing management’s process for developing the fair value of acquired proved natural gas and oil properties; (iii) evaluating the appropriateness of the discounted cash flow models; (iv) testing the completeness and accuracy of underlying data used in the discounted cash flow models; and (v) evaluating the reasonableness of significant assumptions used by management related to future production volumes, future commodity prices, and the weighted average cost of capital rate. Evaluating the reasonableness of management’s significant assumption related to future commodity prices involved comparing the future commodity prices against observable market data and evaluating commodity price differentials through inspection of the underlying contracts. Professionals with specialized skill and knowledge were used to assist in evaluating the appropriateness of the discounted cash flow models and the reasonableness of the weighted average cost of capital rate significant assumption. The work of management’s specialists was used in performing the procedures to evaluate the reasonableness of the proved natural gas and oil reserves as stated in the Critical Audit Matter titled “Impact of Proved Natural Gas, Oil and NGL Reserves on Natural Gas and Oil Properties” 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 completeness and accuracy of the data used by the specialists, and an evaluation of the specialists’ findings.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
March 1, 2022

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, 2021	2020	2019
Operating Revenues:			
Gas sales	$ 3,412	$ 967	$ 1,241
Oil sales	394	154	223
NGL sales	890	265	274
Marketing	1,963	917	1,297
Other	8	5	3
	6,667	2,308	3,038
Operating Costs and Expenses:			
Marketing purchases	1,957	946	1,320
Operating expenses	1,170	813	720
General and administrative expenses	138	121	166
Merger-related expenses	76	41	—
Restructuring charges	7	16	11
Loss on sale of operating assets	—	—	2
Depreciation, depletion and amortization	546	357	471
Impairments	6	2,830	16
Taxes, other than income taxes	132	55	62
	4,032	5,179	2,768
Operating Income (Loss)	2,635	(2,871)	270
Interest Expense:			
Interest on debt	220	171	166
Other interest charges	13	11	8
Interest capitalized	(97)	(88)	(109)
	136	94	65
Gain (Loss) on Derivatives	(2,436)	224	274
Gain (Loss) on Early Extinguishment of Debt	(93)	35	8
Other Income (Loss), Net	5	1	(7)
Income (Loss) Before Income Taxes	(25)	(2,705)	480
Provision (Benefit) for Income Taxes			
Current	—	(2)	(2)
Deferred	—	409	(409)
	—	407	(411)
Net Income (Loss)	$ (25)	$ (3,112)	$ 891
Earnings (Loss) Per Common Share			
Basic	$ (0.03)	$ (5.42)	$ 1.65
Diluted	$ (0.03)	$ (5.42)	$ 1.65
Weighted Average Common Shares Outstanding:			
Basic	789,657,776	573,889,502	539,345,343
Diluted	789,657,776	573,889,502	540,382,914

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)	2021	2020	2019
Net income (loss)	$ (25)	$ (3,112)	$ 891
Change in value of pension and other postretirement liabilities:			
Amortization of prior service cost and net (gain) loss, including (gain) loss on settlements and curtailments included in net periodic pension cost (1)	2	3	8
Net actuarial gain (loss) incurred in period (2)	11	(8)	(5)
Total change in value of pension and postretirement liabilities	13	(5)	3
Comprehensive income (loss)	$ (12)	$ (3,117)	$ 894

(1) Includes $0.4 million and $2 million in tax effects for the years ended December 31, 2021 and 2019, respectively, which were netted against a valuation allowance and therefore included in accumulated other comprehensive income. The year ended December 31, 2020 is presented net of $1 million in taxes.

(2) Includes $2.7 million and ($1) million in tax effects for the years ended December 31, 2021 and 2019, respectively, which were netted against a valuation allowance and therefore included in accumulated other comprehensive income. The year ended December 31, 2020 is presented net of ($2) million in taxes.

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2021	December 31, 2020
ASSETS	*(in millions, except share amounts)*	
Current assets:		
Cash and cash equivalents	$ 28	$ 13
Accounts receivable, net	1,160	368
Derivative assets	183	241
Other current assets	42	49
Total current assets	1,413	671
Natural gas and oil properties, using the full cost method, including $2,231 million as of December 31, 2021 and $1,472 million as of December 31, 2020 excluded from amortization	33,631	27,261
Other	509	523
Less: Accumulated depreciation, depletion and amortization	(24,202)	(23,673)
Total property and equipment, net	9,938	4,111
Operating lease assets	187	163
Long-term derivative assets	226	146
Deferred tax assets	—	—
Other long-term assets	84	69
Total long-term assets	497	378
TOTAL ASSETS	$ 11,848	$ 5,160
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 206	$ —
Accounts payable	1,282	573
Taxes payable	93	74
Interest payable	75	58
Derivative liabilities	1,279	245
Current operating lease liabilities	42	42
Other current liabilities	75	20
Total current liabilities	3,052	1,012
Long-term debt	5,201	3,150
Long-term operating lease liabilities	142	117
Long-term derivative liabilities	632	183
Pension and other postretirement liabilities	23	45
Other long-term liabilities	251	156
Total long-term liabilities	6,249	3,651
Commitments and contingencies (Note 10)		
Equity:		
Common stock, $0.01 par value; 2,500,000,000 shares authorized; issued 1,158,672,666 shares as of December 31, 2021 and 718,795,700 as of December 31, 2020	12	7
Additional paid-in capital	7,150	5,093
Accumulated deficit	(4,388)	(4,363)
Accumulated other comprehensive loss	(25)	(38)
Common stock in treasury, 44,353,224 shares as of December 31, 2021 and 2020	(202)	(202)
Total equity	2,547	497
TOTAL LIABILITIES AND EQUITY	$ 11,848	$ 5,160

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)	For the years ended December 31, 2021	2020	2019
Cash Flows From Operating Activities:			
Net income (loss)	$ (25)	$ (3,112)	$ 891
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	546	357	471
Amortization of debt issuance costs	9	9	8
Impairments	6	2,830	16
Deferred income taxes	—	409	(409)
(Gain) loss on derivatives, unsettled	944	138	(94)
Stock-based compensation	2	3	8
(Gain) loss on early extinguishment of debt	93	(35)	(8)
Loss on sale of assets	—	—	2
Other	(3)	6	10
Changes in assets and liabilities, net of effect of Mergers:			
Accounts receivable	(425)	50	234
Accounts payable	261	(131)	(141)
Taxes payable	(4)	(7)	—
Interest payable	6	(11)	—
Inventories	(3)	2	(7)
Other assets and liabilities	(44)	20	(17)
Net cash provided by operating activities	1,363	528	964
Cash Flows From Investing Activities:			
Capital investments	(1,032)	(896)	(1,099)
Proceeds from sale of property and equipment	4	12	54
Cash acquired in mergers	66	3	—
Cash paid in mergers	(1,642)	—	—
Net cash used in investing activities	(2,604)	(881)	(1,045)
Cash Flows From Financing Activities:			
Payments on current portion of long-term debt	—	—	(52)
Payments on long-term debt	(1,177)	(72)	(54)
Payments on revolving credit facility	(6,628)	(1,671)	(532)
Borrowings under revolving credit facility	6,388	2,337	566
Change in bank drafts outstanding	5	1	(19)
Repayment of revolving credit facilities associated with Mergers	(176)	(200)	—
Repayment of Montage senior notes	—	(522)	—
Proceeds from issuance of long-term debt	2,900	350	—
Debt issuance and other financing costs	(53)	(10)	(3)
Proceeds from issuance of common stock	—	152	—
Purchase of treasury stock	—	—	(21)
Cash paid for tax withholding	(3)	(4)	(1)
Other	—	—	1
Net cash provided by (used in) financing activities	1,256	361	(115)
Increase (decrease) in cash and cash equivalents	15	8	(196)
Cash and cash equivalents at beginning of year	13	5	201
Cash and cash equivalents at end of year	$ 28	$ 13	$ 5

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		Additional		Accumulated Other	Common Stock in Treasury		
(in millions, except share amounts)	Shares Issued	Amount	Paid-In Capital	Accumulated Deficit	Comprehensive Income (Loss)	Shares	Amount	**Total**
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 consideration	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**
Comprehensive loss								
Net loss	—	—	—	(25)	—	—	—	(25)
Other comprehensive income	—	—	—	—	13	—	—	13
Total comprehensive loss	—	—	—	—	—	—	—	(12)
Stock-based compensation	—	—	2	—	—	—	—	2
Issuance of restricted stock	289,442	—	—	—	—	—	—	—
Cancellation of restricted stock	(405)	—	—	—	—	—	—	—
Restricted units granted	2,184,681	—	8	—	—	—	—	8
Performance units vested	1,001,505	—	4	—	—	—	—	4
Merger consideration	437,164,919	5	2,046	—	—	—	—	2,051
Tax withholding – stock compensation	(763,176)	—	(3)	—	—	—	—	(3)
Balance at December 31, 2021	**1,158,672,666**	**$ 12**	**$ 7,150**	**$ (4,388)**	**$ (25)**	**44,353,224**	**$ (202)**	**$ 2,547**

The accompanying notes are an integral part of these 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"). 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 as well as associated NGLs and oil, with ongoing operations focused on the development of unconventional natural gas and oil reservoirs located in Pennsylvania, West Virginia, Ohio and Louisiana. The Company's operations in Pennsylvania, West Virginia and Ohio, herein referred to as "Appalachia," are primarily focused on the Marcellus Shale, the Utica and the Upper Devonian unconventional natural gas and liquids reservoirs. The Company's operations in Louisiana, herein referred to as "Haynesville," are primarily focused on the Haynesville and Bossier natural gas reservoirs. The Company also operates drilling rigs and provides certain oilfield products and services, principally serving the Company's E&P operations through vertical integration.

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.

The comparability of certain 2021 amounts to prior periods could be impacted as a result of the Montage Merger (as defined below) in November 2020, the Indigo Merger (as defined below) on September 1, 2021, and the GEPH Merger (as defined below) on December 31, 2021. The Company believes the disclosures made are adequate to make the information presented not misleading.

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 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, 2021, 2020 and 2019 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, 2021 one purchaser accounted for 12% of annual 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 a default. For the year ended December 31, 2020, one purchaser accounted for 10% of annual revenues. No other purchasers accounted for more than 10% of consolidated revenues. 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 Company had $28 million and $13 million in cash and cash equivalents as of December 31, 2021 and 2020, respectively.

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 $21 million and $16 million as of December 31, 2021 and 2020, 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. Prices used to calculate the ceiling value of reserves were as follows:

	For the years ended December 31,		
	2021	2020	2019
Natural gas *(per MMBtu)*	$ 3.60	$ 1.98	$ 2.58
Oil *(per Bbl)*	$ 66.56	$ 39.57	$ 55.69
NGLs *(per Bbl)*	$ 28.65	$ 10.27	$ 11.58

Using the average quoted prices above, adjusted for market differentials, the net book value of the Company's United States natural gas and oil properties did not exceed the ceiling amount at December 31, 2021 or 2019. The net book value of its natural gas and oil properties exceeded the ceiling amount in each quarter of 2020 resulting in a total non-cash full cost ceiling test impairment of $2,825 million. The Company had no derivative positions that were designated for hedge accounting as of December 31, 2021, 2020 and 2019. 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 future non-cash impairments to the Company's natural gas and oil properties.

No impairment expense was recorded in 2020 or 2021 in relation to the Company's natural gas and oil properties acquired from Montage. These properties were recorded at fair value as of November 13, 2020, in accordance with Accounting Standards Codification ("ASC") Topic 820 – *Fair Value Measurement*. In the fourth quarter of 2020, pursuant to SEC guidance, the Company determined that the fair value of the properties acquired at the closing of the Montage 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 Montage 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 could continue to demonstrate that the fair value of properties acquired clearly exceeded the full cost ceiling limitation beyond a reasonable doubt in each reporting period. As part of the waiver received from the SEC, the Company was 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 Montage Merger was based on future commodity market pricing for natural gas and oil pricing existing at the date of the Montage Merger, and management affirmed that there has not been a material decline to the fair value of these acquired assets since the Montage Merger. The properties acquired in the Montage Merger had 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. Due to the improvement in commodity prices during 2021, no impairment charge would have been recorded in 2021 had the Montage natural gas and oil properties been included in the full cost ceiling test.

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, 2021, the Company had a total of $2,231 million of costs excluded from the amortization base, all of which related to its properties in the United States.

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, 2021	December 31, 2020
Water facilities	$ 237	$ 228
Gathering systems	56	54
Technology infrastructure	135	133
Drilling rigs and equipment	28	26
Land, buildings and leasehold improvements	16	41
Other	37	41
Less: Accumulated depreciation and impairment	(319)	(311)
Total	$ 190	$ 212

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, 2021 and 2020 the Company recognized non-cash impairments of $6 million and $5 million, respectively, for 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, 2021 and 2020, the Company had $48 million and $57 million, respectively, in marketing-related intangible assets, of which $43 million and $48 million were included in Other long-term assets on the respective consolidated balance sheets. The Company amortized $8 million of its marketing-related intangible asset in December 31, 2021 and $9 million in each of the years ended December 31, 2020 and 2019, and expects to amortize $5 million in 2022 and 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, 2021. 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 2039. 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 Cuts and Jobs 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.

On December 31, 2021, the Company issued 99,337,748 shares of its common stock in conjunction with the GEPH Merger. These shares of the Company's common stock had an aggregate dollar value equal to approximately $463 million, based on the closing price of $4.66 per share of its common stock on the NYSE on December 31, 2021. See Note 2 for additional details on the GEPH Merger.

In September 2021, the Company issued 337,827,171 shares of its common stock in conjunction with the Indigo Merger. These shares of the Company's common stock had an aggregate dollar value equal to approximately $1,588 million, based on the closing price of $4.70 per share of its common stock on the NYSE on September 1, 2021. See Note 2 for additional details on the Indigo Merger.

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 Montage 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 consideration. See Note 2 for additional details on the Montage Merger.

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 2 for additional details regarding the Company's use of proceeds from the equity offering.

As part of a share repurchase program, the Company 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, 2021, 2020 and 2019:

	For the years ended December 31,		
(in millions, except share/per share amounts)	2021	2020	2019
Net income (loss)	$ (25)	$ (3,112)	$ 891
Number of common shares:			
Weighted average outstanding	789,657,776	573,889,502	539,345,343
Issued upon assumed exercise of outstanding stock options	—	—	—
Effect of issuance of non-vested restricted common stock	—	—	361,380
Effect of issuance of non-vested restricted units	—	—	—
Effect of issuance of non-vested performance units	—	—	676,191
Weighted average and potential dilutive outstanding	789,657,776	573,889,502	540,382,914
Earnings (loss) per common share:			
Basic	$ (0.03)	$ (5.42)	$ 1.65
Diluted	$ (0.03)	$ (5.42)	$ 1.65

The following table presents the common stock shares equivalent excluded from the calculation of diluted earnings per share for the years ended December 31, 2021, 2020 and 2019, as they would have had an antidilutive effect:

	For the years ended December 31,		
	2021	2020	2019
Unexercised stock options	3,683,363	4,427,040	5,078,253
Unvested share-based payment	832,989	962,662	1,728,264
Restricted units	2,226,981	4,452,876	—
Performance units	2,194,477	2,818,653	271,268
Total	8,937,810	12,661,231	7,077,785

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, 2021, 2020 and 2019:

	For the years ended December 31,		
(in millions)	2021	2020	2019
Cash paid during the year for interest, net of amounts capitalized	$ 106	$ 75	$ 58
Cash paid (received) during the year for income taxes	— (1)	(32)	(52)
Non-cash investing activities	3,690 (2)	1,084 (3)	41
Non-cash financing activities	2,051 (4)	213 (5)	—

(1) Cash received in 2021 for income taxes was immaterial.

(2) Includes $3,039 million and $575 million in non-cash property additions related to the Indigo Merger and the GEPH Merger, respectively.

(3) Includes $1,097 million in non-cash additions related to the Montage Merger.

(4) Includes $1,588 million and $463 million in common stock consideration related to the Indigo Merger and the GEPH Merger, respectively.

(5) Common stock consideration 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. In 2021, two types of performance unit awards were granted. One type of award includes a performance condition based on return on capital employed and a performance condition based on a reinvestment rate, and the second type of award includes one 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, 2021 and 2020, 2,035 shares and 3,632 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 Financial Accounting Standards Board (the "FASB") issued ASU 2018-14, Disclosure Framework – Changes to the Disclosure Requirements for Defined Benefit Plans ("ASU 2018-14"). ASU 2018-14 amends, adds and removes certain disclosure requirements under FASB Accounting Standards Codification ("ASC") Topic 715 – Compensation – Retirement Benefits. The guidance in ASU 2018-14 is effective for fiscal years beginning after December 15, 2020 and was adopted on January 1, 2021. Adoption of ASU 2018-14 resulted in certain disclosure changes within the Company's footnote disclosures. The adoption of ASU 2018-14 did not have a material impact on the Company's consolidated financial statements. Refer to Pension Plan and Other Postretirement Benefits footnote.

In December 2019, the FASB issued ASU 2019-12, Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes. ASU 2019-12 eliminates certain exceptions to the guidance in Topic 740 related to the approach for intraperiod tax allocation, the methodology for calculating income taxes in an interim period and the recognition of deferred tax liabilities for outside basis differences. The new guidance also clarifies certain aspects of the existing guidance, among other things. The standard became effective for interim and annual periods beginning after December 15, 2020 and shall be applied on either a prospective basis, a retrospective basis for all periods presented or a modified retrospective basis through a cumulative-effect adjustment to retained earnings depending on which aspects of the new standard are applicable to an entity. The Company adopted the new standard on January 1, 2021 on a prospective basis, which did not have a material impact on its consolidated financial statements.

New Accounting Standards Not Yet Adopted in this Report

In March 2020, the FASB issued ASU 2020-04, Reference Rate Reform, as a new 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 was 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 USD-LIBOR settings are expected to be published through June 2023 and Southwestern will use a variation of this rate until the underlying agreements are extended beyond the LIBOR publication date. The standard was adopted on January 1, 2022 and did not have a significant impact on Southwestern's consolidated financial statements upon adoption.

(2) ACQUISITIONS AND DIVESTITURES

GEP Haynesville, LLC Merger

On November 3, 2021, Southwestern entered into an Agreement and Plan of Merger with Mustang Acquisition Company, LLC ("Mustang"), GEP Haynesville, LLC ("GEPH") and GEPH Unitholder Rep, LLC (the "GEPH Merger Agreement"). Pursuant to the terms of the GEPH Merger Agreement, GEPH merged with and into Mustang, a subsidiary of Southwestern, and became a wholly-owned subsidiary of Southwestern (the "GEPH Merger"). The GEPH Merger closed on December 31, 2021 and expanded the Company's operations in the Haynesville.

Under the terms and conditions of the GEPH Merger Agreement, the outstanding equity interests in GEPH were cancelled and converted into the right to receive $1,269 million in cash consideration and 99,337,748 shares of Southwestern common stock. These shares of Southwestern common stock had an aggregate dollar value equal to approximately $463 million, based on the closing price of $4.66 per share of Southwestern common stock on the NYSE on December 31, 2021. In addition, the Company assumed GEPH's revolving line of credit balance of $81 million as of December 31, 2021. This balance was subsequently repaid, and the GEPH revolving line of credit was retired on December 31, 2021. See Note 1 and Note 9 for additional information.

The GEPH Merger constituted a business combination, and was accounted for using the acquisition method of accounting. For tax purposes, the GEPH Merger was treated as a sale of partnership interests and an acquisition of assets. The following table presents the fair value of consideration transferred to GEPH equity holders as a result of the GEPH Merger:

(in millions, except share, per share amounts)		As of December 31, 2021
Shares of Southwestern common stock issued		99,337,748
NYSE closing price per share of Southwestern common shares on December 31, 2021	$	4.66
	$	463
Cash consideration		1,269
Total consideration	$	1,732

The following table sets forth the preliminary fair value of the assets acquired and liabilities assumed as of the acquisition date. Certain data and studies necessary to complete the purchase price allocation are still under evaluation, including, but not limited to, the final actualization of accrued liabilities and receivable balances and the valuation of natural gas and oil properties. The Company will finalize the purchase price allocation during the twelve-month period following the acquisition date, during which time the value of the assets and liabilities may be revised as appropriate.

(in millions)		As of December 31, 2021
Consideration:		
Total consideration	$	1,732
Fair Value of Assets Acquired:		
Cash and cash equivalents		11
Accounts receivable		171
Other current assets		3
Commodity derivative assets		56
Evaluated oil and gas properties		1,783
Unevaluated oil and gas properties		59
Other property, plant and equipment		2
Other long-term assets		3
Total assets acquired		2,088
Fair Value of Liabilities Assumed:		
Accounts payable		170
Other current liabilities		1
Derivative liabilities		75
Revolving credit facility		81
Asset retirement obligations		24
Other noncurrent liabilities		5
Total liabilities assumed		356
Net Assets Acquired and Liabilities Assumed	$	1,732

The assets acquired and liabilities assumed were recorded at their preliminary estimated fair values at the date of the GEPH Merger. Acquired working capital amounts are expected to approximate fair value due to their short-term nature. 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.

With the completion of the GEPH Merger, Southwestern acquired proved and unproved properties of approximately $1,783 million and $59 million, respectively, primarily associated with the Haynesville and Bossier formations. The remaining $2 million in Other property, plant and equipment consists of land, facilities and various equipment.

The income approach was utilized for unevaluated and evaluated oil and gas properties based on underlying reserve projections at the GEPH 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.

The Company considered the borrowings under the revolving credit facility to approximate fair value as the balance on the GEPH revolving credit facility was immediately paid off after the GEPH Merger close. The value of derivative instruments was based on observable inputs, primarily forward commodity-price curves, and is considered Level 2.

Since the date of the GEPH Merger occurred on December 31, 2021, there were no revenues or operating income associated with the operations acquired recorded in the Company's consolidated statements of operations for the year ended December 31, 2021.

Indigo Natural Resources Merger

On June 1, 2021, Southwestern entered into an Agreement and Plan of Merger with Ikon Acquisition Company, LLC ("Ikon"), Indigo Natural Resources LLC ("Indigo") and Ibis Unitholder Representative LLC (the "Indigo Merger Agreement"). Pursuant to the terms of the Indigo Merger Agreement, Indigo merged with and into Ikon, a subsidiary of Southwestern, and became a wholly-owned subsidiary of Southwestern (the "Indigo Merger"). On August 27, 2021, Southwestern's stockholders voted to approve the Indigo Merger and the transaction closed on September 1, 2021. The Indigo Merger established Southwestern's natural gas operations in the Haynesville and Bossier Shales.

The outstanding equity interests in Indigo were cancelled and converted into the right to receive (i) $373 million in cash consideration, subject to adjustment as provided in the Indigo Merger Agreement, and (ii) 337,827,171 shares of Southwestern common stock. These shares of Southwestern common stock had an aggregate dollar value equal to approximately $1,588 million, based on the closing price of $4.70 per share of Southwestern common stock on the NYSE on September 1, 2021. Additionally, Southwestern assumed $700 million in aggregate principal amount of Indigo's 5.375% Senior Notes due 2029 (the "Indigo Notes") with a fair value of $726 million as of September 1, 2021, which were subsequently exchanged for $700 million of newly issued 5.375% Senior Notes due 2029. In addition, the Company assumed Indigo's revolving line of credit balance of $95 million as of September 1, 2021. This balance was subsequently repaid, and the Indigo revolving line of credit was retired in September 2021. See Note 1 and Note 9 for additional information.

The Indigo Merger constituted a business combination, and was accounted for using the acquisition method of accounting. For tax purposes, the Indigo Merger was treated as a sale of partnership interests and an acquisition of assets. The following table presents the fair value of consideration transferred to Indigo equity holders as a result of the Indigo Merger:

(in millions, except share, per share amounts)		As of September 1, 2021
Shares of Southwestern common stock issued		337,827,171
NYSE closing price per share of Southwestern common shares on September 1, 2021	$	4.70
	$	1,588
Cash consideration		373
Total consideration	$	1,961

The following table sets forth the preliminary fair value of the assets acquired and liabilities assumed as of the acquisition date. Certain data and studies necessary to complete the purchase price allocation are still under evaluation, including, but not limited to, the valuation of natural gas and oil properties and the resolution of certain matters that the Company is indemnified for under the Indigo Merger Agreement for which not enough information is available to assess the final fair value of at this time. The Company will finalize the purchase price allocation during the twelve-month period following the acquisition date, during which time the value of the assets and liabilities may be revised as appropriate.

(in millions)		As of September 1, 2021
Consideration:		
Total consideration	$	1,961
Fair Value of Assets Acquired:		
Cash and cash equivalents		55
Accounts receivable		192
Other current assets		2
Commodity derivative assets		2
Evaluated oil and gas properties		2,724
Unevaluated oil and gas properties (1)		684
Other property, plant and equipment		4
Other long-term assets		27
Total assets acquired		3,690
Fair Value of Liabilities Assumed:		
Accounts payable (1)		274
Other current liabilities		55
Derivative liabilities		501
Revolving credit facility		95
Senior unsecured notes		726
Asset retirement obligations		8
Other noncurrent liabilities		70
Total liabilities assumed		1,729
Net Assets Acquired and Liabilities Assumed	$	1,961

(1) Reflects an $8 million purchase price adjustment due to ongoing valuation.

The assets acquired and liabilities assumed were recorded at their preliminary estimated fair values at the date of the Indigo Merger. Acquired working capital amounts are expected to approximate fair value due to their short-term nature. 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.

With the completion of the Indigo Merger, Southwestern acquired proved and unproved properties of approximately $2,724 million and $684 million, respectively, primarily associated with the Haynesville and Bossier formations. The remaining $4 million in Other property, plant and equipment consists of land, water facilities and various equipment.

The income approach was utilized for unevaluated and evaluated oil and gas properties based on underlying reserve projections at the Indigo 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.

The measurement of senior unsecured notes was based on unadjusted quoted prices in an active market and are Level 1. The Company considered the borrowings under the 2018 credit facility to approximate fair value as the outstanding Indigo revolving credit facility was immediately paid off after the Indigo Merger close. The value of derivative instruments was based on observable inputs, primarily forward commodity-price and interest-rate curves and is considered Level 2.

From the date of the Indigo Merger through December 31, 2021, revenues and operating income associated with the operations acquired through the Indigo Merger totaled $682 million and $472 million, respectively.

Prior to the Indigo Merger, in May 2021, Indigo closed on an agreement to divest its Cotton Valley natural gas and oil properties. Indigo retained certain contractual commitments related to volume commitments associated with natural gas gathering, for which Southwestern will assume the obligation to pay the gathering provider for any unused portion of the volume commitment under the agreement through 2027, depending on the buyer’s actual use. As of December 31, 2021, up to approximately $36 million of these contractual commitments remain, and the Company has recorded a $17 million liability for the estimated future payments.

Excluding the Cotton Valley gathering agreement (discussed above), the Company has recorded additional liabilities totaling $74 million as of December 31, 2021, primarily related to purchase or volume commitments associated with gathering, fresh water and sand. These amounts will be recognized as payments are made over a period ranging from two to seven years.

Montage Resources Merger

In August 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 “Montage Merger”). On November 12, 2020, Montage’s stockholders voted to approve the Montage Merger and it was made effective on November 13, 2020. The Montage 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.

In anticipation of the Montage 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 2018 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 Montage Merger. See Note 1 and Note 9 for additional information.

The Montage 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 Montage 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

The following table sets forth the fair value of the assets acquired and liabilities assumed as of the acquisition date. The purchase price allocation is complete as of the fourth quarter of 2021.

(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 [(1)]		100
Other property, plant and equipment		28
Other long-term assets		26
Total assets acquired		1,254
Fair value of liabilities assumed:		
Accounts payable [(1)]		155
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		1,041
Net assets acquired and liabilities assumed	$	213

(1) Reflects a $10 million purchase price adjustment due to completion of valuation assessments during the measurement period.

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

With the completion of the Montage Merger, Southwestern acquired proved and unproved properties of approximately $1,012 million and $100 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.

Unevaluated oil and gas properties were valued primarily using a market approach based on comparable transactions for similar properties. The income approach was utilized for proved oil and gas properties based on underlying reserve projections at the Montage 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 2018 credit facility to approximate fair value as the outstanding Montage revolving credit facility was immediately paid off after the Montage Merger closed. The value of derivative instruments was based on observable inputs, primarily forward commodity-price and interest-rate curves and is considered Level 2.

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

Pro Forma Information

The following table summarizes the unaudited pro forma condensed financial information of Southwestern as if the Montage Merger had occurred on January 1, 2019, and the Indigo Merger and the GEPH Merger each had occurred on January 1, 2020:

(in millions, except per share amounts)	For the years ended December 31, 2021 [(1)]	2020	2019
Revenues	$ 8,301	$ 3,836	$ 3,673
Net income (loss) attributable to common stock	$ (354)	$ (3,243)	$ 995
Net income (loss) attributable to common stock per share – basic	$ (0.32)	$ (2.92)	$ 1.48
Net income (loss) attributable to common stock per share – diluted	$ (0.32)	$ (2.92)	$ 1.48

(1) The year ended December 31, 2021 includes the actual operating results from the Montage Merger, which occurred in November 2020.

The unaudited pro forma information is not necessarily indicative of the operating results that would have occurred had the Montage Merger been completed at January 1, 2019, and the Indigo Merger and the GEPH Merger each been completed at January 1, 2020, nor is it necessarily indicative of future operating results of the combined entities. The unaudited pro forma information gives effect to the Mergers and any related equity and debt issuances, along with the use of proceeds therefrom, as if they had occurred on the respective dates discussed above and is a result of combining the statements of operations of Southwestern with the pre-merger results of Montage, Indigo and GEPH, including adjustments for revenues and direct expenses. The pro forma results exclude any cost savings anticipated as a result of the Mergers, and 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 any retirement of assumed senior notes, credit facilities, all related accrued interest and the associated decrease in amortization of issuance costs related to notes retired and revolving lines of credit. These decreases were partially offset by increases in interest on debt associated with the issuance of $350 million in 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. Interest expense was also adjusted to include the impact of the assumption and exchange of Indigo’s $700 million of 5.375% Senior Notes due 2029 for equivalent Southwestern senior notes and to reflect the retirement of the Montage, Indigo and GEPH credit facilities, all related accrued interest and the associated decreases in amortization of issuance costs related to the respective revolving lines of credit. Management believes the estimates and assumptions are reasonable, and the relative effects of the three Mergers are properly reflected.

Merger-Related Expenses

The following table summarizes the merger-related expenses incurred for the years ended December 31, 2021 and 2020:

	For the years ended December 31, 2021				2020
(in millions)	Indigo Merger	GEPH Merger	Montage Merger	**Total**	Montage Merger
Professional fees (bank, legal, consulting)	$ 27	$ 19	$ 1	**$ 47**	$ 18
Representation & warranty insurance	4	7	—	**11**	—
Contract buyouts, terminations and transfers	7	1	—	**8**	5
Due diligence and environmental	3	1	—	**4**	—
Employee-related	2	—	1	**3**	17
Other	2	—	1	**3**	1
Total merger-related expenses	$ 45	$ 28	$ 3	**$ 76**	$ 41

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.

(3) RESTRUCTURING CHARGES

As part of a strategic effort to reposition its portfolio, optimize operational performance and improve margins, the Company incurred charges in recent years 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 in December 2018. 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, 2021, 2020 and 2019:

	For the years ended December 31,		
(in millions)	2021	2020	2019
Severance (including payroll taxes)	$ 7	$ 16	$ 5
Office consolidation	—	—	6
Total restructuring charges [(1)]	$ 7	$ 16	$ 11

(1) All restructuring charges were recorded on the Company's E&P segment for all years presented.

On February 24, 2021, the Company notified employees of a workforce reduction plan as part of an ongoing strategic effort to reposition its portfolio, optimize operational performance and improve margins. 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, 2021, and were substantially complete by the end of the first quarter of 2021.

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. 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.

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 for the year ended December 31, 2019.

In July 2019, the Company terminated its existing lease agreement in its headquarters office building and entered into a new 10 years 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 liabilities associated with the Company’s restructuring activities at December 31, 2021, which are reflected in accounts payable on the consolidated balance sheet:

(in millions)	
Liability at December 31, 2020	$ 3
Additions	7
Distributions	(10)
Liability at December 31, 2021	**$ —**

(4) LEASES

As part of the Indigo Merger, the Company acquired $4 million of operating right of use assets and corresponding lease liabilities which were recognized as part of the Company’s acquisition accounting in the third quarter of 2021. The Company also acquired $2 million of operating right of use assets and corresponding lease liabilities related to the GEPH Merger of which $1 million had already commenced and was reflected on the balance sheet as of December 31, 2021. The GEPH Merger closed during the fourth quarter of 2021.

The Company’s variable lease costs are primarily comprised of variable operating charges incurred in connection with its headquarters lease. The variable lease costs 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:

(in millions)	For the years ended December 31, 2021	2020	2019
Operating lease cost	$ 54	$ 48	$ 45
Short-term lease cost	15	35	45
Variable lease cost	3	3	1
Total lease cost	$ 72	$ 86	$ 91

As of December 31, 2021, the Company had operating leases of $13 million, related primarily to compressor leases, which have been executed but not yet commenced. These operating leases are planned to commence during 2022 with lease terms expiring through 2025. The Company's existing operating leases do not contain any material restrictive covenants.

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

(in millions)	For the years ended December 31, 2021	2020	2019
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows from operating leases	$ 53	$ 47	$ 47
Right-of-use assets obtained in exchange for operating liabilities:			
Operating leases	$ 73	$ 48	$ 95

Supplemental balance sheet information related to leases is as follows:

(in millions)	December 31, 2021	December 31, 2020
Right-of-use asset balance:		
Operating leases	$ 187	$ 163
Lease liability balance:		
Current operating leases	$ 42	$ 42
Long-term operating leases	142	117
Total operating leases	$ 184	$ 159
Weighted average remaining lease term: *(years)*		
Operating leases	5.5	5.6
Weighted average discount rate:		
Operating leases	6.77%	5.97%

Maturity analysis of operating lease liabilities:

(in millions)	December 31, 2021
2022	$ 53
2023	42
2024	31
2025	28
2026	25
Thereafter	42
Total undiscounted lease liability	221
Imputed interest	(37)
Total discounted lease liability	$ 184

(5) REVENUE RECOGNITION

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.

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, 2021				
Gas sales	$ 3,358	$ —	$ 54	**$ 3,412**
Oil sales	389	—	5	**394**
NGL sales	888	—	2	**890**
Marketing	—	6,186	(4,223)	**1,963**
Other (1)	5	3	—	**8**
Total	**$ 4,640**	**$ 6,189**	**$ (4,162)**	**$ 6,667**
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**

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

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 Appalachia and Haynesville.

	For the years ended December 31,		
(in millions)	2021	2020	2019
Appalachia	$ 3,955	$ 1,348	$ 1,700
Haynesville	682	—	—
Other	3	—	3
Total	$ 4,640	$ 1,348	$ 1,703

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, 2021	December 31, 2020
Receivables from contracts with customers	$ 1,085	$ 350
Other accounts receivable	75	18
Total accounts receivable	$ 1,160	$ 368

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, 2021 and 2020. 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, 2021, 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 price 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 that, 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 stated terms of the contract, and receives a payment from the counterparty if the price differential is less than the stated terms of the contract.
Options (Calls and Puts)	The Company purchases and sells options in exchange for premiums. 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 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 purchases a put option, the Company receives from the counterparty the excess (if any) of the strike price over the market price of the put option at the time of settlement, but if the market price is above the put's strike price, no payment is due from either party. If the Company sells a put option, the Company pays the counterparty the excess (if any) of the strike price over the market price of the put option at the time of settlement, but if the market price is above the put'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, 2021:

Financial Protection on Production

	Volume *(Bcf)*	Weighted Average Price per MMBtu					Fair value at December 31, 2021 *($ in millions)*
		Swaps	Sold Puts	Purchased Puts	Sold Calls	Basis Differential	
Natural Gas							
2022							
Fixed price swaps	806	$ 3.08	$ —	$ —	$ —	$ —	$ (486)
Two-way costless collars	144	—	—	2.71	3.14	—	(95)
Three-way costless collars	347	—	2.06	2.52	2.94	—	(286)
Total	1,297						$ (867)
2023							
Fixed price swaps	489	$ 3.07	$ —	$ —	$ —	$ —	$ (143)
Two-way costless collars	219	—	—	3.03	3.55	—	(19)
Three-way costless collars	215	—	2.09	2.54	3.00	—	(136)
Total	923						$ (298)
2024							
Fixed price swaps	224	$ 2.96	$ —	$ —	$ —	$ —	$ (39)
Two-way costless collars	44	$ —	$ —	$ 3.07	$ 3.53	$ —	4
Three-way costless collars	11	$ —	$ 2.25	$ 2.80	$ 3.54	$ —	(5)
Total	279						$ (40)
Basis swaps							
2022	322	$ —	$ —	$ —	$ —	$ (0.38)	$ 68
2023	200	—	—	—	—	(0.45)	(1)
2024	46	—	—	—	—	(0.71)	—
2025	9	—	—	—	—	(0.64)	1
Total	577						$ 68

	Volume *(MBbls)*	Weighted Average Price per Bbl				Fair value at December 31, 2021 *($ in millions)*
		Swaps	Sold Puts	Purchased Puts	Sold Calls	
Oil						
2022						
Fixed price swaps	3,203	$ 53.54	$ —	$ —	$ —	$ (60)
Three-way costless collars	1,380	—	39.89	50.23	57.05	(23)
Total	4,583					$ (83)
2023						
Fixed price swaps	846	$ 55.98	$ —	$ —	$ —	$ (8)
Three-way costless collars	1,268	—	33.97	45.51	56.12	(18)
Total	2,114					$ (26)
2024						
Fixed price swaps	54	$ 53.15	$ —	$ —	$ —	$ (1)

	Volume *(MBbls)*	Weighted Average Price per Bbl: Swaps	Sold Puts	Purchased Puts	Sold Calls	Fair value at December 31, 2021 *($ in millions)*
Ethane						
2022						
Fixed price swaps	5,797	$ 11.37	$ —	$ —	$ —	$ (8)
Two-way costless collars	135	—	—	7.56	9.66	(1)
Total	5,932					$ (9)
2023						
Fixed price swaps	432	$ 11.67	$ —	$ —	$ —	$ —
Propane						
2022						
Fixed price swaps	6,369	$ 31.14	$ —	$ —	$ —	$ (76)
Three-way costless collars	305	$ —	$ 16.80	$ 21.00	31.92	(4)
Total	6,674					$ (80)
2023						
Fixed price swaps	518	$ 33.62	$ —	$ —	—	$ (1)
Normal Butane						
2022						
Fixed price swaps	1,587	$ 32.86	$ —	$ —	$ —	$ (26)
2023						
Fixed price swaps	164	$ 37.84	$ —	$ —	$ —	$ —
Natural Gasoline						
2022						
Fixed price swaps	1,840	$ 52.85	$ —	$ —	$ —	$ (33)
2023						
Fixed price swaps	157	$ 58.65	$ —	$ —	$ —	$ (1)

Other Derivative Contracts

	Volume *(Bcf)*	Weighted Average Strike Price per MMBtu	Fair value at December 31, 2021 *($ in millions)*
Call Options – Natural Gas (Net)			
2022	84	$ 3.01	$ (67)
2023	46	2.94	(33)
2024	9	3.00	(9)
Total	139		$ (109)
Put Options – Natural Gas			
2022	5	$ 2.00	$ —

Storage (1)	Volume *(Bcf)*	Weighted Average Strike Price per MMBtu: Swaps	Basis Differential	Fair value at December 31, 2021 *($ in millions)*
2022				
Purchased fixed price swap	—	$ 2.14	$ —	$ —
Fixed price swaps	2	2.82	—	(1)
Basis swaps	1	—	(0.57)	—
Total	3			$ (1)

(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.

At December 31, 2021, the net fair value of the Company's financial instruments was a $1,502 million liability, including a net reduction of the liability of $3 million due to a non-performance risk adjustment. See Note 8 for additional details regarding the Company's fair value measurements of its derivative positions.

As of December 31, 2021, 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, 2021 and 2020:

Derivative Assets

		Fair Value	
(in millions)	Balance Sheet Classification	December 31, 2021	December 31, 2020
Derivatives not designated as hedging instruments:			
Purchased fixed price swaps – natural gas	Derivative assets	$ —	$ 1
Fixed price swaps – natural gas	Derivative assets	79	37
Fixed price swaps – oil	Derivative assets	—	13
Fixed price swaps – ethane	Derivative assets	2	—
Fixed price swaps – propane	Derivative assets	2	—
Fixed price swaps – normal butane	Derivative assets	1	—
Two-way costless collars – natural gas	Derivative assets	9	54
Three-way costless collars – natural gas	Derivative assets	12	57
Three-way costless collars – oil	Derivative assets	1	15
Basis swaps – natural gas	Derivative assets	77	60
Call options – natural gas	Derivative assets	—	4
Fixed price swaps – natural gas	Other long-term assets	64	7
Fixed price swaps – oil	Other long-term assets	—	2
Two-way costless collars – natural gas	Other long-term assets	100	20
Three-way costless collars – natural gas	Other long-term assets	37	87
Three-way costless collars – oil	Other long-term assets	3	15
Basis swaps – natural gas	Other long-term assets	22	15
Interest rate swaps	Other long-term assets	2	—
Total derivative assets		$ 411	$ 387

Derivative Liabilities

(in millions)	Balance Sheet Classification	Fair Value December 31, 2021	Fair Value December 31, 2020
Derivatives not designated as hedging instruments:			
Fixed price swaps – natural gas storage	Derivative liabilities	$ 1	$ —
Fixed price swaps – natural gas	Derivative liabilities	565	7
Fixed price swaps – oil	Derivative liabilities	60	12
Fixed price swaps – ethane	Derivative liabilities	10	10
Fixed price swaps – propane	Derivative liabilities	78	36
Fixed price swaps – normal butane	Derivative liabilities	27	8
Fixed price swaps – natural gasoline	Derivative liabilities	33	13
Two-way costless collars – natural gas	Derivative liabilities	104	43
Two-way costless collars – oil	Derivative liabilities	—	1
Two-way costless collars – ethane	Derivative liabilities	1	—
Three-way costless collars – natural gas	Derivative liabilities	298	82
Three-way costless collars – oil	Derivative liabilities	24	15
Three-way costless collars – propane	Derivative liabilities	4	—
Basis swaps – natural gas	Derivative liabilities	9	3
Call options – natural gas	Derivative liabilities	67	12
Put options – natural gas	Derivative liabilities	—	1
Swaptions – natural gas	Derivative liabilities	—	2
Fixed price swaps – natural gas	Other long-term liabilities	246	3
Fixed price swaps – oil	Other long-term liabilities	9	2
Fixed price swaps – propane	Other long-term liabilities	1	2
Fixed price swaps – normal butane	Other long-term liabilities	—	1
Fixed price swaps – natural gasoline	Other long-term liabilities	1	2
Two-way costless collars – natural gas	Other long-term liabilities	115	21
Two-way costless collars – oil	Other long-term liabilities	—	—
Three-way costless collars – natural gas	Other long-term liabilities	178	103
Three-way costless collars – oil	Other long-term liabilities	21	15
Basis swaps – natural gas	Other long-term liabilities	22	7
Call options – natural gas	Other long-term liabilities	42	28
Total derivative liabilities		$ 1,916	$ 429

Net Derivative Position

	As of December 31, 2021	As of December 31, 2020
	(in millions)	
Net current derivative liabilities	$ (1,098)	$ (4)
Net long-term derivative liabilities	(407)	(38)
Non-performance risk adjustment	3	1
Net total derivative liabilities	$ (1,502)	$ (41)

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, 2021 and 2020:

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, 2021	2020
		(in millions)	
Purchased fixed price swaps – natural gas	Gain (Loss) on Derivatives	$ (1)	$ 2
Fixed price swaps – natural gas	Gain (Loss) on Derivatives	(237)	(25)
Fixed price swaps – oil	Gain (Loss) on Derivatives	(70)	—
Fixed price swaps – ethane	Gain (Loss) on Derivatives	2	(21)
Fixed price swaps – propane	Gain (Loss) on Derivatives	(40)	(60)
Fixed price swaps – normal butane	Gain (Loss) on Derivatives	(18)	(9)
Fixed price swaps – natural gasoline	Gain (Loss) on Derivatives	(18)	(15)
Two-way costless collars – natural gas	Gain (Loss) on Derivatives	(83)	10
Two-way costless collars – oil	Gain (Loss) on Derivatives	1	(1)
Two-way costless collars – propane	Gain (Loss) on Derivatives	—	(1)
Three-way costless collars – natural gas	Gain (Loss) on Derivatives	(375)	(78)
Three-way costless collars – oil	Gain (Loss) on Derivatives	(41)	3
Three-way costless collars – propane	Gain (Loss) on Derivatives	(4)	—
Basis swaps – natural gas	Gain (Loss) on Derivatives	3	59
Call options – natural gas	Gain (Loss) on Derivatives	(68)	(10)
Call options – oil	Gain (Loss) on Derivatives	—	1
Put options – natural gas	Gain (Loss) on Derivatives	1	—
Swaptions – natural gas	Gain (Loss) on Derivatives	2	7
Fixed price swaps – natural gas storage	Gain (Loss) on Derivatives	(1)	(1)
Interest rate swaps	Gain (Loss) on Derivatives	2	—
Total loss on unsettled derivatives		$ (945)	$ (139)

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, 2021	2020
		(in millions)	
Purchased fixed price swaps – natural gas	Gain (Loss) on Derivatives	$ 7	$ (3)
Purchased fixed price swaps – oil	Gain (Loss) on Derivatives	1	—
Fixed price swaps – natural gas	Gain (Loss) on Derivatives	(418)	142 [(2)]
Fixed price swaps – oil	Gain (Loss) on Derivatives	(86)	65
Fixed price swaps – ethane	Gain (Loss) on Derivatives	(39)	6
Fixed price swaps – propane	Gain (Loss) on Derivatives	(173)	18
Fixed price swaps – normal butane	Gain (Loss) on Derivatives	(53)	(2)
Fixed price swaps – natural gasoline	Gain (Loss) on Derivatives	(59)	(1)
Two-way costless collars – natural gas	Gain (Loss) on Derivatives	(325)	(5)
Two-way costless collars – oil	Gain (Loss) on Derivatives	(4)	17
Two-way costless collars – propane	Gain (Loss) on Derivatives	—	2
Two-way costless collars – ethane	Gain (Loss) on Derivatives	(2)	—
Three-way costless collars – natural gas	Gain (Loss) on Derivatives	(335)	38
Three-way costless collars – oil	Gain (Loss) on Derivatives	(29)	9
Basis swaps – natural gas	Gain (Loss) on Derivatives	92	76
Call options – natural gas	Gain (Loss) on Derivatives	(66)	—
Call options – oil	Gain (Loss) on Derivatives	(2)	—
Put options - natural gas	Gain (Loss) on Derivatives	(2) [(3)]	—
Purchased fixed price swaps – natural gas storage	Gain (Loss) on Derivatives	2	(1)
Fixed price swaps – natural gas storage	Gain (Loss) on Derivatives	(1)	2
Interest rate swaps	Gain (Loss) on Derivatives	—	(1)
Total gain (loss) on settled derivatives		$ (1,492)	$ 362

(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 swaps 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 put options for the year ended December 31, 2021, which is included in gain (loss) on derivatives on the consolidated statements of operations.

Total Gain (Loss) on Derivatives Recognized in Earnings

	For the years ended December 31, 2021	2020
	(in millions)	
Total loss on unsettled derivatives	$ (945)	$ (139)
Total gain (loss) on settled derivatives	(1,492)	362
Non-performance risk adjustment	1	1
Total gain (loss) on derivatives	$ (2,436)	$ 224

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

In 2021, 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, 2021:

	For the year ended December 31, 2021		
(in millions)	Pension and Other Postretirement	Foreign Currency	**Total**
Beginning balance, December 31, 2020	$ (24)	$ (14)	**$ (38)**
Other comprehensive income before reclassifications	11	—	**11**
Amounts reclassified from other comprehensive income (1)	2	—	**2**
Net current-period other comprehensive income	13	—	**13**
Ending balance, December 31, 2021	**$ (11)**	**$ (14)**	**$ (25)**

(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, 2021
Pension and other postretirement: (1)		*(in millions)*
Amortization of prior service cost and net loss	Other income, net	$ 1
Settlement loss	Other income, net	1
	Provision for income taxes (2)	—
Total reclassifications for the period	Net income	$ 2

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

(2) As of December 31, 2021, the Company maintained a tax valuation allowance, therefore there was no tax effect on net income.

(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, 2021 and 2020 were as follows:

	December 31, 2021		December 31, 2020	
(in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	$ 28	$ 28	$ 13	$ 13
2018 revolving credit facility due April 2024	460	460	700	700
Term Loan B due 2027	550	550	—	—
Senior notes (1)	4,430	4,745	2,471	2,609
Derivative instruments, net	(1,502)	(1,502)	(41)	(41)

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

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. Due to limited trading activity, 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 more actively traded remaining senior notes are considered to be a Level 1 measurement. The carrying values of the borrowings under both the Company's 2018 credit facility (to the extent utilized) and Term Loan approximates fair value because the interest rates are variable and reflective of market rates. The Company considers the fair values of its 2018 credit facility and Term Loan 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, 2021, 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 $3 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, 2021 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 and put options, two-way costless collars, and three-way costless collars (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. Swaptions are valued using a variant of the Black-Scholes model referred to as the Black Swaption model, which uses its own separate volatility inputs.

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, 2021			
	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	$ —	$ —	$ —	$ —
Fixed price swaps	—	148	—	148
Two-way costless collars	—	109	—	109
Three-way costless collars	—	53	—	53
Basis swaps	—	99	—	99
Interest rate swaps	—	2	—	2
Liabilities: [1]				
Fixed price swaps	—	(1,031)	—	(1,031)
Two-way costless collars	—	(220)	—	(220)
Three-way costless collars	—	(525)	—	(525)
Basis swaps	—	(31)	—	(31)
Call options	—	(109)	—	(109)
Put options	—	—	—	—
Swaptions	—	—	—	—
Total	$ —	$ (1,505)	$ —	$ (1,505)

(1) Excludes a net reduction to the liability fair value of $3 million related to estimated non-performance risk.

	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: [1]				
Fixed price swaps	—	(96)	—	(96)
Two-way costless collars	—	(65)	—	(65)
Three-way costless collars	—	(215)	—	(215)
Basis swaps	—	(10)	—	(10)
Call options	—	(40)	—	(40)
Put options	—	(1)	—	(1)
Swaptions	—	(2)	—	(2)
Total	$ —	$ (42)	$ —	$ (42)

(1) Excludes a net reduction to the liability fair value of $1 million related to estimated non-performance risk.

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

The Company completed the Indigo Merger and the GEPH Merger on September 1, 2021 and December 31, 2021, respectively. In November 2020, the Company completed the Montage Merger. See Note 2 for a discussion of the fair value measurement of assets acquired and liabilities assumed.

In the third quarter of 2021, the Company determined that the carrying value of certain non-core assets exceeded their respective fair value less costs to sell and recognized a $6 million non-cash impairment. The Company used Level 3 measurements to determine the fair value of these assets.

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.

(9) DEBT

The components of debt as of December 31, 2021 and 2020 consisted of the following:

	December 31, 2021			
(in millions)	Debt Instrument	Unamortized Issuance Expense	Unamortized Debt Premium / Discount	Total
Current portion of long-term debt:				
4.10% Senior Notes due March 2022	$ 201	$ —	$ —	$ 201
Variable rate (3.0% at December 31, 2021) Term Loan B due June 2027	$ 5 (1)	$ —	$ —	$ 5
Total current portion of long-term debt	$ 206	$ —	$ —	$ 206
Long-term debt:				
Variable rate (2.08% at December 31, 2021) 2018 revolving credit facility, due April 2024	$ 460	$ — (2)	$ —	$ 460
4.95% Senior Notes due January 2025 (3)	389	(1)	—	388
Variable rate (3.0% at December 31, 2021) Term Loan B due June 2027	545	(7)	(1)	537
7.75% Senior Notes due October 2027	440	(4)	—	436
8.375% Senior Notes due September 2028	350	(5)	—	345
5.375% Senior Notes due February 2029	700	(6)	25	719
5.375% Senior Notes due March 2030	1,200	(17)	—	1,183
4.75% Senior Notes due February 2032	1,150	(17)	—	1,133
Total long-term debt	$ 5,234	$ (57)	$ 24	$ 5,201
Total debt	$ 5,440	$ (57)	$ 24	$ 5,407

	December 31, 2020			
(in millions)	Debt Instrument	Unamortized Issuance Expense	Unamortized Debt Premium / Discount	Total
Long-term debt:				
Variable rate (2.11% at December 31, 2020) 2018 revolving credit facility, due April 2024	$ 700	$ — (2)	$ —	$ 700
4.10% Senior Notes due March 2022	207	—	—	207
4.95% Senior Notes due January 2025 (3)	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

(1) The Term Loan requires quarterly principal repayments of $1.375 million, subject to adjustment for voluntary prepayments, beginning in March 2022.

(2) At December 31, 2021 and 2020, unamortized issuance expense of $10 million and $12 million, respectively, associated with the 2018 credit facility (as defined below) was classified as other long-term assets on the consolidated balance sheet.

(3) 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 their issuance. 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 was paid in January 2021. On September 1, 2021, S&P upgraded the Company's bond rating to BB, and on January 6, 2022, S&P further upgraded our bond rating to BB+, which will have the effect of decreasing the interest rate on the 2025 Notes to 5.95% beginning with coupon payments paid after January 2022.

The following is a summary of scheduled debt maturities by year as of December 31, 2021 and includes the quarterly Term Loan principal repayments of $1.375 million, subject to adjustment for voluntary prepayments, beginning in March 2022:

(in millions)		
2022 (1)	$	206
2023		6
2024 (2)		465
2025		395
2026		5
Thereafter		4,363
	$	5,440

(1) In January 2022, the remaining $201 million principal balance on the Senior Notes due 2022 was retired using the Company's 2018 credit facility.

(2) The Company's 2018 credit facility matures in 2024.

Credit Facility

2018 Credit Facility

In April 2018, the Company entered into a 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 2021, the banks participating in the 2018 credit facility reaffirmed the elected borrowing base and aggregate commitments to be $2.0 billion. The borrowing base is subject to redetermination at least twice a year, which typically occurs in April and October, and 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.

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 Indigo and GEPH consolidated EBITDAX prior to the respective Mergers 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, 2021, 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, 2021, the Company had $160 million in letters of credit and $460 million in borrowings outstanding under the 2018 credit facility. The Company currently does not anticipate being required to supply a materially greater amount of letters of credit under its existing contracts.

The Company's exposure to the anticipated transition from LIBOR is limited to the 2018 credit facility. The USD-LIBOR settings are expected to be published through June 2023, and Southwestern anticipates using a variation of this rate until the underlying agreements are extended beyond the LIBOR publication date.

Term Loan Credit Agreement

On December 22, 2021, the Company entered into a term loan credit agreement with a group of lenders that provided for a $550 million secured term loan facility which matures in June 2027 (the "Term Loan"). As of December 31, 2021, the Company had borrowings under this Term Loan of $550 million. The net proceeds from the initial loans of $542 million were used to fund a portion of the GEPH Merger on December 31, 2021. Beginning on March 31, 2022, the Term Loan will require minimum quarterly payments of $1.375 million, subject to adjustment for voluntary prepayments. The Term Loan is subject to varying rates of interest based on whether the term loan is a term benchmark loan or an alternate base rate loan. Term benchmark loans bear interest at the adjusted term secured overnight financing rate (which includes a credit spread adjustment and is subject to a floor that is 0.50%) plus an applicable margin equal to 2.50%. Alternate base rate loans bear interest at the alternate base rate plus an applicable margin equal to 1.50%. The current borrowings are considered benchmark loans and are carried an interest rate of 3.00% as of December 31, 2021 (0.50% floor plus 2.50% margin).

The term loan is subject to a quarterly collateral coverage ratio test in which the Company's PDP PV-10 value, net of derivative mark-to-market value, must be greater than 2.0x its secured debt commitments or all secured debt becomes callable. If necessary, outstanding secured debt principal can be paid down within 45 days of the end of such fiscal quarter to come into compliance with this ratio, either by (i) prepaying the loans, (ii) prepaying the loans under the 2018 credit facility, (iii) prepaying any other secured indebtedness that is secured by a lien, or some combination thereof.

The Company's obligations under the Term Loan are guaranteed by each of the Company's subsidiaries that guarantee the obligations under the 2018 credit facility and are secured by liens on substantially all the assets of the Company and the Company's subsidiaries on an equal basis with the liens securing the obligations under the 2018 credit facility.

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 their issuance. 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 was paid in January 2021. On September 1, 2021, S&P upgraded the Company's bond rating to BB, and on January 6, 2022, S&P further upgraded the Company's bond rating to BB+, which will have the effect of decreasing the interest rate on the 2025 Notes to 5.95% beginning with coupon payments paid after January 2022.

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.

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 2018 credit facility, were utilized to fund a redemption of $510 million of Montage's Notes in connection with the closing of the Montage Merger.

On August 30, 2021, Southwestern closed its public offering of $1,200 million aggregate principal amount of its 5.375% Senior Notes due 2030 (the "2030 Notes"), with net proceeds from the offering totaling $1,183 million after underwriting discounts and offering expenses. The proceeds were used to repurchase the remaining $618 million of the Company's 7.50% Senior Notes due 2026, $167 million of the Company's 4.95% Senior Notes due 2025 and $6 million of the Company's 4.10% Senior Notes due 2022 for $845 million, and the Company recognized a $60 million loss on the extinguishment of debt, which included the write-off of $6 million in related unamortized debt discounts and debt issuance costs. The remaining proceeds were used to pay borrowings under its 2018 credit facility and for general corporate purposes.

Upon the close of the Indigo Merger on September 1, 2021, and pursuant to the terms of the Indigo Merger Agreement, Southwestern assumed $700 million in aggregate principal amount of Indigo's 5.375% Senior Notes due 2029 ("Indigo Notes"). As part of purchase accounting, the assumption of the Indigo Notes resulted in a non-cash fair value adjustment of $26 million, based on the market price of 103.766% on September 1, 2021, the date that the Indigo Merger closed. Subsequent to the Indigo Merger, the Company exchanged the Indigo Notes for approximately $700 million of newly issued 5.375% Senior Notes due 2029, which were registered with the SEC in November 2021.

On December 22, 2021, Southwestern closed its public offering of $1,150 million aggregate principal amount of its 4.75% Senior Notes due 2032 (the "2032 Notes"), with net proceeds from the offering totaling $1,133 million after underwriting discounts and offering expenses. The net proceeds of this offering, along with the net proceeds from the Term Loan, were used to fund the cash consideration portion of the GEPH Merger, which closed on December 31, 2021, and to pay $332 million to fund tender offers for $300 million of our 2025 Notes for which the Company recorded an additional loss on extinguishment of debt of $33 million, which included the write-off of $1 million in related unamortized debt discounts and debt issuance costs. The remaining proceeds were used for general corporate purposes.

(10) COMMITMENTS AND CONTINGENCIES

Operating Commitments and Contingencies

As of December 31, 2021, 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 $10.5 billion, $872 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 $869 million of that amount. As of December 31, 2021, 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	**$ 9,584**	$ 1,141	$ 1,932	$ 1,731	$ 2,167	$ 2,613
Pending regulatory approval and/or construction (1)	**872**	3	114	163	249	343
Total transportation charges	**$ 10,456**	$ 1,144	$ 2,046	$ 1,894	$ 2,416	$ 2,956

(1) Based on the estimated in-service dates as of December 31, 2021.

Prior to the Indigo Merger, in May 2021, Indigo closed on an agreement to divest its Cotton Valley natural gas and oil properties. Indigo retained certain contractual commitments related to volume commitments associated with natural gas gathering, for which Southwestern assumed the obligation to pay the gathering provider for any unused portion of the volume commitment under the agreement through 2027, depending on the buyer's actual use. As of December 31, 2021, up to approximately $36 million of these contractual commitments remain (included in the table above), and the Company has recorded a $17 million liability for its portion of the estimated future payments.

Excluding the Cotton Valley gathering agreement (discussed above), the Company has recorded additional liabilities totaling $74 million as of December 31, 2021, primarily related to purchase or volume commitments associated with gathering, fresh water and sand. These amounts are reflected above and will be recognized as payments are made over the next six years.

The Company leases pressure pumping equipment for its E&P operations under two leases that expire in 2027 and 2028. The current aggregate annual payment under these leases is approximately $7 million. The Company has seven leases for drilling rigs for its E&P operations that expire through 2028 with a current aggregate annual payment of approximately $10 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, 2021, future minimum payments under these non-cancelable leases accounted for as operating leases (including short-term) are approximately $38 million in 2022, $34 million in 2023, $27 million in 2024, $26 million in 2025, $24 million in 2026 and $38 million thereafter.

The Company also has commitments for compression services and compression rentals related to its E&P segment. As of December 31, 2021, future minimum payments under these non-cancelable agreements (including short-term obligations) are approximately $24 million in 2022, $10 million in 2023, $4 million in 2024 and less than $1 million in 2025.

In the first quarter of 2019, the Company agreed to purchase firm transportation with pipelines in the Appalachian basin from 2021 through 2032. The table above includes $327 million for the remaining contractual commitments for which the seller has agreed to reimburse $100 million to the Company.

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, 2021, the Company does not currently have any material amounts accrued related to litigation matters, including the cases discussed below. 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 requested 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 accepted coverage. On June 15, 2021, the parties agreed to a settlement of the case without any admission of liability. The Company's insurance carrier is fully funding the settlement amount. On October 21, 2021, the court orally approved the settlement agreement. It signed a final judgment dismissing the litigation on October 22, 2021.

Bryant Litigation

As further discussed in Note 2, on September 1, 2021, the Company completed the Indigo Merger, resulting in the assumption of Indigo's existing litigation.

On June 12, 2018, a collection of 51 individuals and entities filed a lawsuit against fifteen oil and gas company defendants, including Indigo, in Louisiana state court claiming damages arising out of current and historical exploration and production activity on certain acreage located in DeSoto Parish, Louisiana. The plaintiffs, who claim to own the properties at issue, assert that Indigo's actions and the actions of other current operators conducting exploration and production activity, combined with the improper plugging and abandoning of legacy wells by former operators, have caused environmental contamination to their properties. Among other things, the plaintiffs contend that the defendants' conduct resulted in the migration of natural gas, along with oilfield contaminants, into the Carrizo-Wilcox aquifer system underlying certain portions of DeSoto Parish. The plaintiffs assert claims based in tort, breach of contract and for violations of the Louisiana Civil and Mineral Codes, and they seek injunctive relief and monetary damages in an unspecified amount, including punitive damages.

On September 13, 2018, Indigo filed a variety of exceptions in response to the plaintiffs' petition in this matter. Since the initial filing, supplemental petitions have been filed joining additional individuals and entities as plaintiffs in the matter. On September 29, 2020, plaintiffs filed their fourth supplemental and amending petition in response to the court's order ruling that plaintiffs' claims were improperly vague and failed to identify with reasonable specificity the defendants' allegedly wrongful conduct. Indigo and the majority of the other defendants filed several exceptions to plaintiffs' fourth amended petition challenging the sufficiency of plaintiffs' allegations and seeking dismissal of certain claims. On February 18, 2021, plaintiffs filed a fifth supplemental and amending petition, which seeks to augment the claims of select plaintiffs. On October 11, 2021, a sixth supplemental petition was filed which seeks to add the Company as a party to the litigation.

The presence of natural gas in a localized area of the Carrizo-Wilcox aquifer system in DeSoto Parish is currently the subject of a regulatory investigation by the Louisiana Office of Conservation ("Conservation"), and the Company is cooperating and coordinating with Conservation in that investigation. The Conservation matter number is EMER18-003.

The Company does not currently expect this matter to have a material impact on its financial position, results of operations, cash flows or liquidity.

Indemnifications

The Company has provided certain indemnifications to various third parties, including in relation to asset and entity dispositions, securities offerings and other financings. 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)	2021	2020	2019
Current:			
Federal	$ —	$ (2)	$ (1)
State	—	—	(1)
	—	(2)	(2)
Deferred:			
Federal	—	371	(431)
State	—	38	22
	—	409	(409)
Provision (benefit) for income taxes	$ —	$ 407	$ (411)

The provision for income taxes was an effective rate of 0% in 2021, (15)% in 2020 and (86)% in 2019. The Company's effective tax rate increased in 2021, as compared with 2020, primarily due to the changes in the valuation allowance and refunds received 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)	2021	2020	2019
Expected provision (benefit) at federal statutory rate	$ (5)	$ (568)	$ 101
Increase (decrease) resulting from:			
State income taxes, net of federal income tax effect	—	(55)	11
Change in valuation allowance	2	1,034	(522)
Other	3	(4)	(1)
Provision (benefit) for income taxes	$ —	$ 407	$ (411)

The components of the Company's deferred tax balances as of December 31, 2021 and 2020 were as follows:

(in millions)	2021	2020
Deferred tax liabilities:		
Right of use lease asset	$ 45	$ 38
Other	3	2
	48	40
Deferred tax assets:		
Differences between book and tax basis of property	—	295
Accrued compensation	44	38
Accrued pension costs	6	11
Asset retirement obligations	25	20
Net operating loss carryforward	585	1,117
Future lease payments	46	38
Derivative activity	362	9
Capital loss carryover	28	27
Other	31	24
	1,127	1,579
Valuation allowance	(1,079)	(1,539)
Net deferred tax asset	$ —	$ —

As the Tax Cuts and Jobs 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 Cuts and Jobs 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.

Due to the issuance of common stock associated with the Indigo Merger, as discussed in Note 2 to the consolidated financial statements to this Annual Report, the Company incurred a cumulative ownership change and as such, the Company's net operating losses ("NOLs") prior to the acquisition are subject to an annual limitation under Internal Revenue Code Section 382 of approximately $48 million. The ownership changes and resulting annual limitation will result in the expiration of NOLs or other tax attributes otherwise available, with a corresponding decrease in the Company's valuation allowance. At December 31, 2021, the Company had approximately $4 billion of federal NOL carryovers, of which approximately $3 billion have an expiration date between 2035 and 2037 and $1 billion have an indefinite carryforward life. The Company currently estimates that approximately $2 billion of these federal NOLs will expire before they are able to be used. The non-expiring NOLs remain subject to a full valuation allowance. If a subsequent ownership change were to occur as a result of future transactions in the Company's common stock, the Company's use of remaining U.S. tax attributes may be further limited. Included in the Company's net operating loss carryforward are the net operating loss carryforwards acquired in the Montage acquisition of $858 million. A portion of the Montage-related net operating loss carryovers is subject to an annual section 382 limitation of $1.7 million, and the Company has appropriately accounted for this limitation in purchase accounting in 2020. 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 $46 million related to interest deduction carryforward as of December 31, 2021.

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.

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.

In 2020, due to significant pricing declines and 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 its deferred tax assets would not be realized and recorded a valuation allowance. As of December 31, 2021, the Company still maintains a full valuation allowance. The Company also retained a valuation allowance of $59 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.

A reconciliation of the changes to the valuation allowance is as follows:

(in millions)	2021	2020
Valuation allowance at beginning of year	$ 1,539	$ 87
Establishment of valuation allowance on opening deferred balance	—	408
Return to accrual adjustments	(31)	6
Current period deferred activity	(1)	626
Reduction due to 382 limitations on NOLs	(428)	(120)
Purchase accounting	—	532
Valuation allowance at end of year	$ 1,079	$ 1,539

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, 2021, there were no unrecognized tax positions identified that would have a material effect on the effective tax rate. All $7 million in uncertain tax positions booked as of December 31, 2018 were released in 2019 due to audit completion and statute expirations.

The Internal Revenue Service closed the 2016 and 2017 audits of the Company's federal returns in 2021 with no change. The income tax years 2018 to 2021 remain open to examination by the major taxing jurisdictions to which the Company is subject.

The Company adopted Accounting Standards Update No. 2019-12 ("ASU 2019-12") in the current period. ASU 2019-12 addressed simplification to income tax accounting rules, such as removing a few exceptions to intraperiod allocation. There was no material impact to the financial statements as a result of this adoption.

(12) ASSET RETIREMENT OBLIGATIONS

The following table summarizes the Company's 2021 and 2020 activity related to asset retirement obligations:

(in millions)	2021	2020
Asset retirement obligation at January 1	$ 85	$ 57
Accretion of discount	6	4
Obligations incurred	1	1
Obligations assumed through mergers	36	28
Obligations settled/removed	(20)	(6)
Revisions of estimates	1	1
Asset retirement obligation at December 31	$ 109	$ 85
Current liability	$ 4	$ 4
Long-term liability	105	81
Asset retirement obligation at December 31	$ 109	$ 85

(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 of contribution expense in each of 2021, 2020 and 2019, respectively. Additionally, the Company capitalized $2 million of contributions in 2021 and $1 million in both 2020 and 2019 directly related to the acquisition, exploration and development activities of the Company's natural gas and oil properties.

Defined Benefit Pension and Other Postretirement Plans

Prior to January 1, 2021, substantially all of the Company's employees were covered by the defined benefit pension, a cash balance plan that provided benefits based upon a fixed percentage of an employee's annual compensation. As part of an ongoing effort to reduce costs, the Company elected to freeze its pension plan effective January 1, 2021. Employees that were participants in the pension plan prior to January 1, 2021 continued to receive the interest component of the plan but no longer received the service component. On September 13, 2021, the Compensation Committee of the Board of Directors approved terminating the Company's pension plan, effective December 31, 2021, subject to approval by the Internal Revenue Service. This decision, among other benefits, will provide plan participants quicker access to, and greater flexibility in, the management of participants' respective benefits due under the plan.

The Company has commenced the pension plan termination process, but the specific date for the completion of the process is unknown at this time and will depend on certain legal and regulatory requirements or approvals. As part of the termination process, the Company expects to distribute lump sum payments to or purchase annuities for the benefit of plan participants, which is dependent on the participants' elections. In addition, the Company expects to make a payment equal to the difference between the total benefits due under the plan and the total value of the assets available, which, as of December 31, 2021, was $11 million.

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.

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.

The following provides a reconciliation of the changes in the plans' benefit obligations, fair value of assets and funded status as of December 31, 2021 and 2020:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	2021	2020	2021	2020
Change in benefit obligations:				
Benefit obligation at January 1	$ 139	$ 126	$ 13	$ 13
Service cost [1]	—	7	2	2
Interest cost	4	5	—	—
Participant contributions	—	—	—	—
Actuarial (gain) loss	(4)	16	(2)	1
Benefits paid	(2)	(13)	—	(1)
Plan amendments	—	—	—	(2)
Curtailments	—	(2)	—	—
Settlements	(11)	—	—	—
Benefit obligation at December 31	$ 126	$ 139	$ 13	$ 13

(1) The Company froze its pension plan effective January 1, 2021, resulting in no service cost for the year ended December 31, 2021.

	Pension Benefits		Other Postretirement Benefits	
(in millions)	2021	2020	2021	2020
Change in plan assets:				
Fair value of plan assets at January 1	$ 106	$ 96	$ —	$ —
Actual return on plan assets	6	11	—	—
Employer contributions	12	12	1	1
Participant contributions	—	—	—	—
Benefits paid	(2)	(13)	(1)	(1)
Settlements	(8)	—	—	—
Fair value of plan assets at December 31	$ 114	$ 106	$ —	$ —
Funded status of plans at December 31 [1]	$ (12)	$ (33)	$ (13)	$ (13)

(1) The funded status of the pension plan includes a $1 million liability related to a supplemental employee retirement plan as of December 31, 2021 and 2020.

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, 2021 and 2020 are as follows:

(in millions)	2021	2020
Projected benefit obligation	$ 126	$ 139
Accumulated benefit obligation	126	139
Fair value of plan assets	114	106

Pension and other postretirement benefit costs include the following components for 2021, 2020 and 2019:

	Pension Benefits			Other Postretirement Benefits		
(in millions)	2021	2020	2019	2021	2020	2019
Service cost [1]	$ —	$ 7	$ 7	$ 2	$ 2	$ 1
Interest cost	4	5	5	—	—	—
Expected return on plan assets	(4)	(6)	(6)	—	—	—
Amortization of transition obligation	—	—	—	—	—	—
Amortization of prior service cost	—	—	—	—	—	—
Amortization of net loss	—	1	2	—	—	—
Net periodic benefit cost	—	7	8	2	2	1
Curtailment gain	—	—	—	—	—	—
Settlement loss	2	—	6	—	—	—
Total benefit cost	$ 2	$ 7	$ 14	$ 2	$ 2	$ 1

(1) The Company froze its pension plan effective January 1, 2021, resulting in no service cost for the year ended December 31, 2021.

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. The Company froze its pension plan effective January 1, 2021, resulting in no service cost for the year ended December 31, 2021. The weighted average interest crediting rate for the pension plan is 6.0%.

The Company recognized a $2 million non-cash settlement loss related to $8 million of lump sum payments from the pension plan for the year ended December 31, 2021. As a result of settlement accounting requirements, the Company recorded a $4 million reduction to its net pension liability as of December 31, 2021, with a corresponding reduction to accumulated other comprehensive loss.

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 restructuring, the Company recognized a $6 million non-cash settlement loss in 2019 related to $21 million of lump sum payments as a result of these restructuring events. In 2020, the settlement loss was immaterial.

Amounts recognized in other comprehensive income for the years ended December 31, 2021 and 2020 were as follows:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	2021	2020	2021	2020
Net actuarial (loss) gain arising during the year	$ 5	$ (12)	$ 2	$ 2
Amortization of prior service cost	—	—	—	—
Amortization of net loss	1	1	—	—
Settlements	5	—	—	—
Curtailments	—	3	—	—
Less: Tax effect [1]	—	3	—	(1)
Amounts recognized in other comprehensive income	$ 11	$ (5)	$ 2	$ 1

(1) Pension and other postretirement benefit tax effects of $2.7 million and $0.4 million, respectively, for the year ended December 31, 2021, were netted against a valuation allowance and therefore included in accumulated other comprehensive income.

Included in accumulated other comprehensive income as of December 31, 2021 and 2020 was a $23 million loss ($18 million net of tax) and a $36 million loss ($28 million net of tax), respectively, related to the Company's pension and other postretirement benefit plans. For the year ended December 31, 2021, $13 million was classified from accumulated other comprehensive income, primarily driven by actuarial gains and settlements. Upon the anticipated termination of the pension plan, the Company expects the remaining associated balance in accumulated other comprehensive income to be reclassified to net income in the periods in which lump sum payments are distributed to, or annuities are purchased for, plan participants.

The assumptions used in the measurement of the Company's benefit obligations as of December 31, 2021 and 2020 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2021	2020	2021	2020
Discount rate	3.20 %	3.10 %	3.10 %	2.80 %
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 2021, 2020 and 2019 are as follows:

	Pension Benefits			Other Postretirement Benefits		
	2021	2020	2019	2021	2020	2019
Discount rate	3.20 %	3.70 %	3.70 %	2.80 %	3.50 %	4.35 %
Expected return on plan assets	0.10 %	6.50 %	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 2021 and 2020:

	2021	2020
Health care cost trend assumed for next year	6.5 %	6.5 %
Rate to which the cost trend is assumed to decline	5.0 %	5.0 %
Year that the rate reaches the ultimate trend rate	2038	2037

Pension Payments and Asset Management

In 2021, the Company contributed $12 million to its pension plan and less than $1 million to its other postretirement benefit plan and does not expect to make any additional contributions to its pension plan until the plan termination is completed.

Although the specific date for the completion of the pension plan termination process is unknown at this time and will depend on certain legal and regulatory requirements or approvals, the Company has adjusted actuarial expectations based on an estimated timeline of approvals and completion. As part of the termination process, the Company expects to distribute lump sum payments to, or purchase annuities for, the benefit plan participants, which is dependent on the participants' elections. The following timeline reflects the Company's current estimate of benefit payments to be made and the timing thereof, including projected future interest costs:

Pension Benefits	
(in millions)	
2022	$ 48
2023	70
2024	—
2025	—
2026	—
Years 2027-2031	—

Other Postretirement Benefits	
(in millions)	
2022	$ 1
2023	1
2024	1
2025	1
2026	1
Years 2027-2031	4

The Company's overall investment strategy has been 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 ("BAC") of the Company, appointed by the Compensation Committee of the Board of Directors, currently administers the Company's pension plan assets. In anticipation of the pension plan termination, the BAC has adjusted the asset-class mix to more investment grade fixed income assets to mitigate equity market risk, while also preserving cash to satisfy potential interim plan termination-related expenditures.

The table below presents the allocations targeted by the BAC and the actual weighted-average asset allocation of the Company's pension plan as of December 31, 2021, by asset category. The asset allocation targets are subject to change and the

BAC 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
Fixed income [(1)]	78 %	78 %
Cash [(2)]	22 %	22 %
Total	100 %	100 %

(1) Includes fixed income pension plan assets in the table below.

(2) 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, 2021 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				
Fixed income [(1)]	90	90	—	—
Cash and cash equivalents	24	24	—	—
Total plan assets at fair value	$ 114	$ 114	$ —	$ —

(1) U.S. Treasury Notes.

Utilizing the fair value hierarchy described in Note 8, the Company's fair value measurement of pension plan assets at December 31, 2020 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 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			

(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.

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 current long-term incentive compensation plans consist of a combination of stock-based awards that derive their value directly or indirectly from the Company's common stock price, and cash-based awards that are fixed in amount but are subject to meeting annual performance thresholds.

The Company recorded the following costs related to long-term incentive compensation for the years ended December 31, 2021, 2020 and 2019:

(in millions)	2021	2020	2019
Long-term incentive compensation – expensed	$ 30	$ 17	$ 17
Long-term incentive compensation – capitalized	18	7	10

Stock-Based Compensation

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 2019, 2020 and 2021 cliff-vest at the end of three years.

As further discussed in Note 3, 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. In February of 2021 and 2020, the Company notified employees of workforce reduction plans as a result of strategic realignments of the Company's organizational structure. Employees affected by these events 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. 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, 2021, 2020 and 2019 on the consolidated statements of operations.

<u>Equity-Classified Awards</u>

Equity-Classified Stock Options

The Company recorded the following compensation costs related to equity-classified stock options for the years ended December 31, 2021, 2020 and 2019:

(in millions)	2021	2020	2019
Stock options – general and administrative expense	$ —	$ —	$ 1
Stock options – capitalized expense	$ —	$ —	$ —

The Company recorded less than $1 million deferred tax assets related to stock options for the years ended December 31, 2021 and 2019, compared to no deferred tax assets for the year ended December 31, 2020. Additionally, the Company had no unrecognized compensation cost related to unvested stock options at December 31, 2021.

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. There were no equity-classified stock options granted or exercised in 2021, 2020 or 2019.

The following tables summarize stock option activity for the years 2021, 2020 and 2019, and provide information for options outstanding at December 31 of each year:

	2021		2020		2019	
	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	3,850	$ 13.39	4,635	$ 15.26	5,178	$ 17.06
Granted	—	$ —	—	$ —	—	$ —
Exercised	—	$ —	—	$ —	—	$ —
Forfeited or expired	(844)	$ 29.10	(785)	$ 24.46	(543)	$ 32.38
Options outstanding at December 31	3,006	$ 8.98	3,850	$ 13.39	4,635	$ 15.26

	Options Outstanding			Options Exercisable		
Range of Exercise Prices	Options Outstanding at December 31, 2021	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Options Exercisable at December 31, 2021	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life
	(in thousands)		*(years)*	*(in thousands)*		*(years)*
$7.74-$29.42	3,006	$ 8.98	1.3	3,006	$ 8.98	1.3

Equity-Classified Restricted Stock

The Company recorded the following compensation costs related to equity-classified restricted stock grants for the years ended December 31, 2021, 2020 and 2019:

(in millions)	2021	2020	2019
Restricted stock grants – general and administrative expense	$ 2	$ 3	$ 6
Restricted stock grants – capitalized expense	$ —	$ 1	$ 4

The Company also recorded deferred tax asset of $1 million related to restricted stock for the year ended December 31, 2021, compared to a deferred tax asset of $2 million and a reduction in the deferred tax asset of less than $1 million for the years ended December 31, 2020 and 2019, respectively. As of December 31, 2021, 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 1.6 years.

The following table summarizes the restricted stock activity for the years 2021, 2020 and 2019, and provides information for restricted stock outstanding at December 31 of each year:

	2021		2020		2019	
	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	697	$ 5.97	1,480	$ 7.00	2,717	$ 7.91
Granted	438	$ 5.18	584	$ 2.86	493	$ 3.06
Vested	(893)	$ 5.81	(1,098)	$ 5.26	(1,516)	$ 7.16
Forfeited	—	$ 8.59	(269) (1)	$ 7.79	(214) (2)	$ 8.38
Unvested shares at December 31	242	$ 5.12	697	$ 5.97	1,480	$ 7.00

(1) Includes 171,813 shares forfeited as a result of the reduction in workforce for the year ended December 31, 2020.

(2) Includes 65,196 shares forfeited as a result of the reduction in workforce for the year ended December 31, 2019.

The fair values of the grants were $2 million for each of 2021, 2020 and 2019. The total fair value of shares vested were $5 million for 2021, $6 million for 2020 and $11 million for 2019.

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 to these equity-classified restricted stock units recorded by the Company was immaterial for the years ended December 31, 2021 and 2020. As of December 31, 2021, 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 1.2 years.

The following table summarizes equity-classified restricted stock unit activity to be paid out in Company stock for the years ended December 31, 2021 and 2020.

	2021		2020	
	Number of Units	Weighted Average Fair Value	Number of Units	Weighted Average Fair Value
	(in thousands)		*(in thousands)*	
Unvested Units at January 1	134	$ 3.05	—	$ —
Granted	—	$ —	186	$ 3.05
Vested	(92)	$ 3.05	(42)	$ 3.05
Forfeited	(5)	$ 3.05	(10)	$ 3.05
Unvested Units at December 31	**37**	**$ 3.05**	**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 and 2019. There have been no equity-classified performance units awarded since 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 costs recognized for the year ended December 31, 2021 associated with equity-classified performance units, and the amounts recognized in 2020 were immaterial.

(in millions)	2021	2020	2019
Performance units – general and administrative expense	$ —	$ —	$ 1
Performance units – capitalized expense	$ —	$ —	$ —

The Company recorded $2 million deferred tax assets related to equity-classified performance units for the year ended December 31, 2021. The Company recorded a deferred tax asset of less than $1 million and $1 million for the years ended December 31, 2020 and 2019, 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, 2021, 2020 and 2019, and provides information for unvested units as of December 31, 2021, 2020 and 2019:

	2021			2020			2019		
	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
Granted	—	$	—	—	$	—	—	$	—
Vested	—	$	—	(178)	$	10.47	(378)	$	9.59
Forfeited	—	$	—	—	$	—	(42) (2)	$	10.47
Unvested shares at December 31	—	$	—	—	$	—	178	$	10.47

(1) These amounts reflect the number of performance units granted in thousands. The actual payout of shares ranged from a minimum of zero shares to a maximum of two shares per unit contingent upon TSR. The performance units had a three-year vesting term and the actual disbursement of shares, if any, was determined during the first quarter following the end of the three-year vesting period.

(2) Included 41,761 units related to the reduction in workforce for the year ended December 31, 2019.

Liability-Classified Awards

Liability-Classified Restricted Stock Units

In the first quarter of each year beginning with 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 awards granted in 2021 vest over a period of three years. 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.

The Company recorded the following compensation costs related to liability-classified restricted stock unit grants for the years ended December 31, 2021, 2020 and 2019:

(in millions)		2021		2020		2019
Restricted stock units – general and administrative expense	$	12	$	5	$	7
Restricted stock units – capitalized expense	$	8	$	2	$	5

The Company also recorded deferred tax assets of $1 million for the year ended December 31, 2021, compared to $1 million and less than $1 million related to liability-classified restricted stock units for the years ended 2020 and 2019, respectively. As of December 31, 2021, there was $19 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 1.7 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 or Company stock for the years ended December 31, 2021, 2020 and 2019 and provides information for unvested units as of December 31, 2021, 2020 and 2019:

	2021			2020			2019		
	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	11,613	$	2.67	12,992	$	2.42	8,202	$	3.41
Granted	1,486	$	4.23	6,172	$	1.41	8,659	$	4.34
Vested	(4,522)	$	3.40	(3,960)	$	1.43	(2,624)	$	4.09
Forfeited	(640) (1)	$	4.56	(3,591) (2)	$	2.67	(1,245) (3)	$	3.48
Unvested units at December 31	7,937	$	4.08	11,613	$	2.67	12,992	$	2.42

(1) Includes 360,253 units related to the reduction in workforce for the year ended December 31, 2021.

(2) Includes 2,010,196 units related to the reduction in workforce for the year ended December 31, 2020.

(3) Includes 400,056 units related to the reduction in workforce for the year ended December 31, 2019.

Liability-Classified Performance Units

In each of the last four years, 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. In 2021, two types of performance unit awards were granted. One type of award includes a performance condition based on return on capital employed and a performance condition based on a reinvestment rate, and the second type of award includes one 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.

The Company recorded the following compensation costs related to liability-classified performance unit grants for the years ended December 31, 2021, 2020 and 2019:

(in millions)		2021		2020		2019
Liability-classified performance units – general and administrative expense	$	12	$	7	$	2
Liability-classified performance units – capitalized expense	$	6	$	2	$	1

The Company also recorded deferred tax assets of $4 million related to liability-classified performance units for the year ended December 31, 2021, compared to a deferred tax asset of $2 million and a reduction of deferred tax asset of less than $1 million for the years ended 2020 and 2019, respectively. As of December 31, 2021, 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 1.6 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, 2021, 2020 and 2019 and provides information for unvested units as of December 31, 2021, 2020 and 2019:

	2021			2020			2019		
	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	8,699	$	2.57	5,142	$	2.42	2,803	$	3.41
Granted	3,580	$	4.14	6,172	$	1.41	2,757	$	4.34
Vested	(2,020)	$	4.05	—	$	—	(43)	$	2.42
Forfeited	(744)	$	3.40	(2,615) (1)	$	3.05	(375) (2)	$	3.12
Unvested units at December 31	9,515	$	2.88	8,699	$	2.57	5,142	$	2.42

(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.

Cash-Based Compensation

Performance Cash Awards

In 2021 and 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 2021 and 2020 include a performance condition determined annually by the Company. For both years, 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.

The Company recorded the following compensation costs related to performance cash awards for the years ended December 31, 2021 and 2020:

(in millions)	2021	2020
Performance cash awards – general and administrative expense	$ 4	$ 2
Performance cash awards – capitalized expense	$ 4	$ 2

The Company also recorded deferred tax assets of $1 million related to performance cash awards for each of the years ended December 31, 2021 and 2020. As of December 31, 2021 there was $21 million of total unrecognized compensation cost related to performance cash awards. This cost is expected to be recognized over a weighted average 2.7 years. The final value of the performance cash awards is contingent upon the Company's actual performance against these performance measures.

The following table summarizes performance cash award activity to be paid out in cash for the years ended December 31, 2021 and 2020 and provides information for unvested units as of December 31, 2021 and 2020:

	2021		2020	
	Number of Units *(in thousands)*	Weighted Average Fair Value	Number of Units *(in thousands)*	Weighted Average Fair Value
Unvested units at January 1	18,353	$ 1.00	—	$ —
Granted	18,546	$ 1.00	20,044	$ 1.00
Vested	(4,955)	$ 1.00	(100)	$ 1.00
Forfeited	(3,672) (1)	$ 1.00	(1,591) (2)	$ 1.00
Unvested Units at December 31	28,272	$ 1.00	18,353	$ 1.00

(1) Includes 1,241,000 units related to the reduction in workforce for the year ended December 31, 2021.

(2) Includes 945,500 units related to the reduction in workforce for the year ended December 31, 2020.

(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**
2021				
Revenues from external customers	$ 4,701	$ 1,966	$ —	**$ 6,667**
Intersegment revenues	(61)	4,223	—	**4,162**
Depreciation, depletion and amortization expense	537	9	—	**546**
Impairments	6	—	—	**6**
Operating income	2,583 (1)	52	—	**2,635**
Interest expense (2)	136	—	—	**136**
Gain (loss) on derivatives	(2,437)	—	1	**(2,436)**
Loss on early extinguishment of debt	—	—	(93)	**(93)**
Other income, net	5	—	—	**5**
Provision for income taxes (2)	—	—	—	**—**
Assets	10,767 (3)	956	125	**11,848**
Capital investments (4)	1,107	—	1	**1,108**

(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)	(5)	(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	(7)	—	**16**
Operating income (loss)	283	(6)	(13)		—	**270**
Interest expense (2)	65		—		—	**65**
Gain on derivatives	274		—		—	**274**
Gain on early extinguishment of debt	—		—		8	**8**
Other income (loss)	(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**

(1) Operating income for the E&P segment includes $7 million of restructuring charges and $76 million of acquisition-related charges for the year ended December 31, 2021.

(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 an increase of $70 million for 2021, a decrease of $3 million for 2020 and an increase of $34 million for 2019 related to the change in accrued expenditures between years.

(5) 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.

(6) Operating income for the E&P segment includes $11 million of restructuring charges for the year ended December 31, 2019.

(7) Marketing includes a $3 million non-cash impairment related to certain non-core midstream gathering assets at December 31, 2019.

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, 2021, 2020 and 2019:

	For the years ended December 31,		
(in millions)	2021	2020	2019
Cash and cash equivalents	$ 28	$ 13	$ 5
Accounts receivable	—	1	—
Income taxes receivable	—	—	30
Prepayments	6	6	8
Property, plant and equipment	12	16	27
Unamortized debt expense	10	11	11
Right-of-use lease assets	65	72	80
Non-qualified retirement plan	4	6	7
	$ 125	$ 125	$ 168

Included in intersegment revenues of the Marketing segment are $4.2 billion, $1.2 billion and $1.6 billion for 2021, 2020 and 2019, 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 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, 2021 and 2020:

(in millions)	2021	2020
Proved properties	$ 31,400	$ 25,789
Unproved properties	2,231	1,472
Total capitalized costs	33,631	27,261
Less: Accumulated depreciation, depletion and amortization	(23,884)	(23,362)
Net capitalized costs	$ 9,747	$ 3,899

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, 2021:

(in millions)	2021	2020	2019	Prior	**Total**
Property acquisition costs	$ 784	$ 85	$ 9	$ 1,079	**$ 1,957**
Exploration and development costs	28	9	7	10	**54**
Capitalized interest	75	48	36	61	**220**
	$ 887	$ 142	$ 52	$ 1,150	**$ 2,231**

Of the total net unevaluated costs excluded from amortization as of December 31, 2021, approximately $1.1 billion is related to undeveloped properties in Appalachia which were acquired in 2014 and 2015, $117 million is related to Montage properties acquired in November 2020 and approximately $759 million is related to the acquisition of undeveloped properties in Haynesville which were acquired in September 2021 and December 2021. Additionally, the Company has approximately $220 million of unevaluated capitalized interest and $51 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)	2021	2020	2019
Unproved property acquisition costs	$ 139	$ 124 (1)	$ 162
Exploration costs	—	—	2
Development costs	984	784	936
Capitalized costs incurred	$ 1,123	$ 908	$ 1,100
Full cost pool amortization per Mcfe	$ 0.42	$ 0.38	$ 0.56

(1) Excluded $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 $97 million, $88 million and $109 million during 2021, 2020 and 2019, 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 $64 million, $56 million and $77 million during 2021, 2020 and 2019, 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)	2021	2020	2019
Sales	$ 4,640	$ 1,348	$ 1,703
Production (lifting) costs	(1,304)	(866)	(781)
Depreciation, depletion and amortization	(537)	(348)	(462)
Impairment of natural gas and oil properties	—	(2,825)	—
	2,799	(2,691)	460
Provision for income taxes (1)	—	—	110
Results of operations (2)	$ 2,799	$ (2,691)	$ 350

(1) Prior to the recognition of a valuation allowance, in 2020 the Company recognized an income tax benefit of $624 million.

(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 99% of the present worth of the Company's total proved reserves as of December 31, 2021. For 2020 and 2019, NSAI's audit accounted for 97% and 99%, respectively, of the then-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 2019, 2020 and 2021, all of which were located in the United States:

	Natural Gas *(Bcf)*	Oil *(MBbls)*	NGL *(MBbls)*	**Total** ***(Bcfe)***
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 (1)	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 (2)	1,911	18,796	55,141	**2,354**
Disposition of reserves in place	—	—	—	**—**
December 31, 2020	**9,181**	**58,024**	**410,151**	**11,990**
Revisions of previous estimates due to price (3)	501	1,414	(15,525)	**415**
Revisions of previous estimates other than price	248	1,900	1,500	**269**
Extensions, discoveries and other additions	2,543	24,865	211,598	**3,962**
Production	(1,015)	(6,610)	(30,940)	**(1,240)**
Acquisition of reserves in place (4)	5,750	247	180	**5,753**
Disposition of reserves in place	(1)	(61)	—	**(1)**
December 31, 2021	**17,207**	**79,779**	**576,964**	**21,148**

(1) 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.

(2) The 2020 acquisition amounts are primarily associated with the Montage Merger.

(3) The 15,525 MBbl reduction in NGL volumes for 2021 is the result of changes to the Company's five-year development plan and elections to retain ethane in the natural gas stream in line with ethane transportation contracts. This election is driven by commodity pricing, whereby higher natural gas pricing relative to ethane pricing creates a more economically favorable position.

(4) The 2021 acquisition amounts are primarily associated with the Indigo Merger and the GEPH Merger.

	Natural Gas *(Bcf)*	Oil *(MBbls)*	NGL *(MBbls)*	**Total** ***(Bcfe)***
Proved developed reserves as of:				
December 31, 2019	4,906	26,124	226,271	**6,421**
December 31, 2020	6,342	33,563	276,548	**8,203**
December 31, 2021	**9,308**	**40,930**	**296,832**	**11,335**
Proved undeveloped reserves as of:				
December 31, 2019	3,724	46,801	382,490	**6,300**
December 31, 2020	2,839	24,461	133,603	**3,787**
December 31, 2021	**7,899**	**38,849**	**280,132**	**9,813**

The Company's estimated proved natural gas, oil and NGL reserves were 21,148 Bcfe at December 31, 2021, compared to 11,990 Bcfe at December 31, 2020. The Company's reserves increased in 2021, compared to 2020, as acquisitions, additions and positive price and performance revisions were only partially offset by production and disposition.

The Company's reserves decreased in 2020, as 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 following table summarizes the changes in reserves for 2019, 2020 and 2021:

(in Bcfe)	Appalachia	Haynesville	Other [(1)]	**Total**
December 31, 2018	**11,920**	**—**	**1**	**11,921**
Net revisions				
Price revisions	(717)	—	—	**(717)**
Performance and production revisions [(2)]	1,102	—	—	**1,102**
Total net revisions	385	—	—	**385**
Extensions, discoveries and other additions				
Proved developed	191	—	—	**191**
Proved undeveloped	1,004	—	—	**1,004**
Total reserve additions	1,195	—	—	**1,195**
Production	(778)	—	—	**(778)**
Acquisition of reserves in place	—	—	—	**—**
Disposition of reserves in place	(2)	—	—	**(2)**
December 31, 2019	**12,720**	**—**	**1**	**12,721**
Net revisions				
Price revisions	(4,370)	—	—	**(4,370)**
Performance and production revisions	1,424	—	—	**1,424**
Total net revisions	(2,946)	—	—	**(2,946)**
Extensions, discoveries and other additions				
Proved developed	267	—	—	**267**
Proved undeveloped	474	—	—	**474**
Total reserve additions	741	—	—	**741**
Production	(880)	—	—	**(880)**
Acquisition of reserves in place	2,354	—	—	**2,354**
Disposition of reserves in place	—	—	—	**—**
December 31, 2020	**11,989**	**—**	**1**	**11,990**
Net revisions				
Price revisions	415	—	—	**415**
Performance and production revisions	270	—	(1)	**269**
Total net revisions	685	—	(1)	**684**
Extensions, discoveries and other additions				
Proved developed	451	—	—	**451**
Proved undeveloped [(3)]	3,511	—	—	**3,511**
Total reserve additions	3,962	—	—	**3,962**
Production	(1,108)	(132)	—	**(1,240)**
Acquisition of reserves in place	—	5,753	—	**5,753**
Disposition of reserves in place	(1)	—	—	**(1)**
December 31, 2021	**15,527**	**5,621**	**—**	**21,148**

(1) Other includes properties outside of Appalachia and Haynesville.

(2) 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.

(3) For the year ended December 31, 2021, net extensions, discoveries and other additions in proved undeveloped reserves of 3,511 Bcfe was comprised of 1,768 Bcfe resulting from the addition of new undeveloped locations throughout the year through the Company's successful drilling program and 1,743 Bcfe which was attributable to undeveloped locations which were uneconomical under prior year SEC pricing (and therefore excluded from prior year reserves) but which have become economical under current SEC pricing.

As of December 31, 2021, the Company had no proved undeveloped reserves that had a negative present value on a 10% discounted basis.

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 that have a negative $207 million present value when discounted at 10%. 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 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 measure of discounted future net cash flows relating to proved natural gas, oil and NGL reserves as of December 31, 2021, 2020 and 2019 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)	2021	2020	2019
Future cash inflows	$ 75,314	$ 17,997	$ 27,003
Future production costs	(23,235)	(11,969)	(14,981)
Future development costs [1]	(6,032)	(1,924)	(3,246)
Future income tax expense	(8,135)	—	(476)
Future net cash flows	37,912	4,104	8,300
10% annual discount for estimated timing of cash flows	(19,181)	(2,257)	(4,600)
Standardized measure of discounted future net cash flows	$ 18,731	$ 1,847	$ 3,700

(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:

	2021	2020	2019
Natural gas *(per MMBtu)*	$ 3.60	$ 1.98	$ 2.58
Oil *(per Bbl)*	66.56	39.57	55.69
NGLs *(per Bbl)*	28.65	10.27	11.58

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 2021, 2020 and 2019:

(in millions)	2021	2020	2019
Standardized measure, beginning of year	$ 1,847	$ 3,700	$ 5,999
Sales and transfers of natural gas and oil produced, net of production costs	(3,332)	(478)	(923)
Net changes in prices and production costs	10,417	(2,720)	(3,510)
Extensions, discoveries, and other additions, net of future production and development costs	3,183	81	234
Acquisition of reserves in place	6,499	443	—
Sales of reserves in place	(1)	—	(2)
Revisions of previous quantity estimates	596	(987)	152
Net change in income taxes	(3,689)	35	491
Changes in estimated future development costs	137	1,241	621
Previously estimated development costs incurred during the year	419	624	704
Changes in production rates (timing) and other	2,470	(466)	(718)
Accretion of discount	185	374	652
Standardized measure, end of year	$ 18,731	$ 1,847	$ 3,700

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, of the effectiveness of our disclosure controls and procedures, as defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act as of the end of the period covered by this Annual Report. 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, 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, concluded that our disclosure controls and procedures were effective as of December 31, 2021 at a reasonable assurance level.

There were 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, 2021, 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 79 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 79 of this Annual Report.

ITEM 9B. OTHER INFORMATION

None.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The definitive proxy statement relating to our 2022 Annual Meeting of Stockholders, to be filed with the SEC pursuant to Regulation 14A on or before May 2, 2022 (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 2022 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 at www.swn.com. 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 2022 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before May 2, 2022, 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 2022 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before May 2, 2022, 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 2022 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before May 2, 2022, 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 2022 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before May 2, 2022, 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 2022 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.

Dated: March 1, 2022	SOUTHWESTERN ENERGY COMPANY By: /s/ CARL F. GIESLER, JR. Carl F. Giesler, Jr. Executive Vice President and Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed, as of March 1, 2022, 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/ CARL F. GIESLER, JR. Carl F. Giesler, Jr.	Executive Vice President and Chief Financial Officer (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)
2.2	Agreement and Plan of Merger, dated as of June 1, 2021, by and between Southwestern Energy Company, Ikon Acquisition Company, LLC, Indigo Natural Resources LLC and Ibis Unitholder Representative (Incorporated by reference to Exhibit 2.1 to the Registrant's Current Report on Form 8-K filed on June 2, 2021)
2.3	Agreement and Plan of Merger, dated as of November 3, 2021, by and between Southwestern Energy Company, Mustang Acquisition Company, LLC, GEP Haynesville, LLC, and GEPH Unitholder Rep, LLC (Incorporated by reference to Exhibit 2.1 to the Registrant's Current Report on Form 8-K filed on November 5, 2021)
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	Certificate of Amendment to Amended and Restated Certificate of Incorporation, dated September 1, 2021 (Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed September 1, 2021)
3.3	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*	Registration Rights Agreement, dated September 1, 2021, by and among Southwestern Energy Company, the other parties thereto, and Ibis Unitholder Representative, LLC
4.5*	Registration Rights Agreement, dated December 31, 2021, by and among Southwestern Energy Company, the other parties thereto, and GEPH Unitholder Rep, LLC
4.6	Exchange and Registration Rights Agreement, dated as of September 3, 2021, among Southwestern Energy Company, the guarantor parties thereto, J.P. Morgan Securities LLC and Credit Agricole Securities (USA) Inc. (Incorporated by reference to Exhibit 4.3 to the Registrant's Current Report on Form 8-K filed on September 3, 2021)
4.7	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)
4.8	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)
4.9	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)
4.10	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)
4.11	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 (Incorporated by reference to Exhibit 4.8 to the Registrant's Annual Report on Form 10-K (Commission File No. 001-08246) for the year ended December 31, 2020)
4.12	Fifth Supplemental Indenture, dated as of September 10, 2021 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 4.6 to the Registrant's Amendment No. 1 to Form S-4 filed on October 12, 2021)
4.13	Sixth Supplemental Indenture, dated as of January 4, 2022 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 January 5, 2022)

4.14	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)
4.15	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)
4.16	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)
4.17	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)
4.18	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)
4.19	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 (Incorporated by reference to Exhibit 4.15 to the Registrant's Annual Report on Form 10-K (Commission File No. 001-08246) for the year ended December 31, 2020)
4.20	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 (Incorporated by reference to Exhibit 4.16 to the Registrant's Annual Report on Form 10-K (Commission File No. 001-08246) for the year ended December 31, 2020)
4.21	Seventh Supplemental Indenture, dated as of September 10, 2021 between Southwestern Energy Company, the guarantors named therein and Regions Bank, as trustee (Incorporated by reference to Exhibit 4.14 to the Registrant's Amendment No. 1 to Form S-4 filed on October 12, 2021)
4.22	Eighth Supplemental Indenture, dated as of January 4, 2022 between Southwestern Energy Company, the guarantors named therein and Regions Bank, as trustee (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on January 5, 2022)
4.23	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)
4.24	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)
4.25	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)
4.26	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 (Incorporated by reference to Exhibit 4.21 to the Registrant's Annual Report on Form 10-K (Commission File No. 001-08246) for the year ended December 31, 2020)
4.27	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)
4.28	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 (Incorporated by reference to Exhibit 4.23 to the Registrant's Annual Report on Form 10-K (Commission File No. 001-08246) for the year ended December 31, 2020)
4.29	Sixth Supplemental Indenture, dated as of August 30, 2021, among Southwestern Energy Company, the guarantors party thereto and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.4 to the Registrant's Current Report on Form 8-K filed on August 30, 2021)
4.30	Seventh Supplemental Indenture, dated as of September 10, 2021 between Southwestern Energy Company, the guarantors named therein and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.23 to the Registrant's Amendment No. 1 to Form S-4 filed on October 12, 2021)
4.31	Eighth Supplemental Indenture, dated as of January 4, 2022 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 January 5, 2022)

4.32	Indenture, dated as of August 30, 2021, between Southwestern Energy Company and Regions Bank, as trustee (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on August 30, 2021)
4.33	First Supplemental Indenture, dated as of August 30, 2021, among Southwestern Energy Company, the guarantors party thereto and Regions Bank, as trustee (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on August 30, 2021)
4.34	Second Supplemental Indenture, dated as of September 3, 2021, among Southwestern Energy Company, the guarantors party thereto and Regions Bank, as trustee (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on September 3, 2021)
4.35	Third Supplemental Indenture, dated as of September 10, 2021 among Southwestern Energy Company, the guarantors named therein and Regions Bank, as trustee (Incorporated by reference to Exhibit 4.31 to Post-Effective Amendment No. 1 on Form S-4 filed on October 12, 2021)
4.36	Fourth Supplemental Indenture, dated as of December 22, 2021, among Southwestern Energy Company, the guarantors party thereto and Regions Bank, as trustee (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on December 22, 2021)
4.37	Fifth Supplemental Indenture, dated as of January 4, 2022 between Southwestern Energy Company, the guarantors named therein and Regions Bank, as trustee (Incorporated by reference to Exhibit 4.4 to the Registrant's Current Report on Form 8-K filed on January 5, 2022)
4.38	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)
4.39	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)
4.40	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)
4.41	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)
4.42	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)
4.43	Form of 5.375% Notes due 2029. (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on September 3, 2021)
4.44	Form of 5.375% Notes due 2030. (Incorporated by reference to Exhibit 4.3 to the Registrant's Current Report on Form 8-K filed on August 30, 2021)
4.45	Form of 4.750% Notes due 2032. (Incorporated by reference to Exhibit 4.3 to the Registrant's Current Report on Form 8-K filed on December 22, 2021)
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 (Incorporated by reference to Exhibit 10.14 to the Registrant’s Annual Report on Form 10-K (Commission File No. 001-08246) for the year ended December 31, 2020)
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 (Incorporated by reference to Exhibit 10.23 to the Registrant’s Annual Report on Form 10-K (Commission File No. 001-08246) for the year ended December 31, 2020)
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 (Incorporated by reference to Exhibit 10.26 to the Registrant’s Annual Report on Form 10-K (Commission File No. 001-08246) for the year ended December 31, 2020)
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 (Incorporated by reference to Exhibit 10.38 to the Registrant’s Annual Report on Form 10-K (Commission File No. 001-08246) for the year ended December 31, 2020)
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 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 (Incorporated by reference to Exhibit 10.42 to the Registrant’s Annual Report on Form 10-K (Commission File No. 001-08246) for the year ended December 31, 2020)
10.43	Amendment No. 10 to Credit Agreement, dated as of June 9, 2021 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 June 9, 2021)
10.44	Amendment No. 11 to Credit Agreement, dated as of November 12, 2021 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 November 15, 2021)
10.45	Term Loan Credit Agreement, dated as of December 22, 2021, among Southwestern Energy Company, the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent and as collateral agent (Incorporated by reference to Exhibit 10.1 to the Registrant’s Current Report on Form 8-K filed on December 22, 2021)
10.46	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)
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 January 28, 2022
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, 2021, (ii) Consolidated Statements of Comprehensive Income for the three years ended December 31, 2021, (iii) Consolidated Balance Sheets as of December 31, 2021 and 2020, (iv) Consolidated Statements of Cash Flows for the three years ended December 31, 2021, (v) Consolidated Statements of Changes in Equity for the three years ended December 31, 2021 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, 2021, formatted in Inline XBRL (included in Exhibit 101)

* Filed herewith
† Management contract or compensatory plan or arrangement

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Southwestern Energy®

2021 ANNUAL REPORT

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