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

FORM 10-Q

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

For the quarterly period ended September 30, 2021
OR

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

Commission File Number 001-35700

Diamondback Energy, Inc.
(Exact Name of Registrant As Specified in Its Charter)

DE	**45-4502447**
(State or Other Jurisdiction of Incorporation or Organization)	**(I.R.S. Employer Identification Number)**
500 West Texas **Suite 1200** **Midland, TX**	**79701**
(Address of principal executive offices)	**(Zip code)**

(432) 221-7400
(Registrant's telephone number, including area code)
Securities registered pursuant to Section 12(b) of the Securities Exchange Act of 1934:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock	FANG	The Nasdaq Stock Market LLC (NASDAQ Global Select Market)

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 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. (Check One):

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 is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

As of October 29, 2021, the registrant had 181,174,549 shares of common stock outstanding.

DIAMONDBACK ENERGY, INC.

FORM 10-Q

FOR THE QUARTER ENDED SEPTEMBER 30, 2021

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GLOSSARY OF OIL AND NATURAL GAS TERMS

The following is a glossary of certain oil and natural gas industry terms that are used in this Quarterly Report on Form 10-Q (this "report"):

Basin	A large depression on the earth's surface in which sediments accumulate.
Bbl or barrel	One stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to crude oil or other liquid hydrocarbons.
BO	One barrel of crude oil.
BOE	One barrel of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.
BOE/d	BOE per day.
British Thermal Unit or Btu	The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.
Completion	The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.
Finding and development costs	Capital costs incurred in the acquisition, exploitation and exploration of proved oil and natural gas reserves divided by proved reserve additions and revisions to proved reserves.
Gross acres or gross wells	The total acres or wells, as the case may be, in which a working interest is owned.
Horizontal wells	Wells drilled directionally horizontal to allow for development of structures not reachable through traditional vertical drilling mechanisms.
MBbl	One thousand barrels of crude oil and other liquid hydrocarbons.
MBO/d	One thousand BO per day.
MBOE/d	One thousand BOE per day.
Mcf	One thousand cubic feet of natural gas.
Mineral interests	The interests in ownership of the resource and mineral rights, giving an owner the right to profit from the extracted resources.
MMBtu	One million British Thermal Units.
Net acres or net wells	The sum of the fractional working interest owned in gross acres.
Net revenue interest	An owner's interest in the revenues of a well after deducting proceeds allocated to royalty and overriding interests.
Oil and natural gas properties	Tracts of land consisting of properties to be developed for oil and natural gas resource extraction.
Plugging and abandonment	Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of all states require plugging of abandoned wells.
Prospect	A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.
Proved reserves	The estimated quantities of oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.
Reserves	The estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to the market and all permits and financing required to implement the project. Reserves are not assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).
Reservoir	A porous and permeable underground formation containing a natural accumulation of producible natural gas and/or crude oil that is confined by impermeable rock or water barriers and is separate from other reservoirs.

Royalty interest	An interest that gives an owner the right to receive a portion of the resources or revenues without having to carry any costs of development, which may be subject to expiration.
Working interest	An operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations.

GLOSSARY OF CERTAIN OTHER TERMS

The following is a glossary of certain other terms that are used in this report:

2019 Indenture	The indenture, dated as of December 5, 2019, among the Company and Wells Fargo, as the trustee, as supplemented by the first supplemental indenture dated as of December 5, 2019, the second supplemental indenture dated as of May 26, 2020, the third supplemental indenture dated as of March 24, 2021, and the fourth supplemental indenture dated as of June 30, 2021, relating to the December 2019 Notes (defined above), the May 2020 Notes (defined below) and the March 2021 Notes (defined below).
2025 Indenture	The indenture relating to the 2025 Senior Notes (defined below), dated as of December 20, 2016, among the Company, the subsidiary guarantor party thereto and Wells Fargo, as the trustee, as supplemented.
2025 Senior Notes	The Company’s 5.375% senior unsecured notes due 2025 issued under the 2025 Indenture.
ASC	Accounting Standards Codification.
ASU	Accounting Standards Update.
December 2019 Notes	The Company’s 2.875% senior unsecured notes due 2024, the Company’s 3.250% senior unsecured notes due 2026 and the Company’s 3.500% senior unsecured notes due 2029 issued under the 2019 Indenture.
Equity Plan	The Company’s Equity Incentive Plan.
Exchange Act	The Securities Exchange Act of 1934, as amended.
FASB	Financial Accounting Standards Board.
GAAP	Accounting principles generally accepted in the United States.
LIBOR	The London interbank offered rate.
May 2020 Notes	The Company’s 4.750% Senior Notes due 2025 issued under the 2019 Indenture.
March 2021 Notes	The Company’s 0.900% Senior Notes due 2023, the Company’s 3.125% Senior Notes due 2031 and the Company’s 4.400% Senior Notes due 2051 issued under the 2019 Indenture.
NYMEX	New York Mercantile Exchange.
OPEC	Organization of the Petroleum Exporting Countries.
Rattler	Rattler Midstream LP, a Delaware limited partnership.
Rattler’s General Partner	Rattler Midstream GP LLC, a Delaware limited liability company; the general partner of Rattler Midstream LP and a wholly owned subsidiary of the Company.
Rattler LLC	Rattler Midstream Operating LLC, a Delaware limited liability company and a subsidiary of Rattler.
SEC	United States Securities and Exchange Commission.
Senior Notes	The 2025 Senior Notes, the December 2019 Notes, the May 2020 Notes and the March 2021 Notes.
Viper	Viper Energy Partners LP, a Delaware limited partnership.
Viper LLC	Viper Energy Partners LLC, a Delaware limited liability company and a subsidiary of Viper.
Wells Fargo	Wells Fargo Bank, National Association.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Various statements contained in this report are “forward-looking statements” as defined by the SEC. These forward-looking statements are subject to a number of risks, uncertainties and assumptions, many of which are beyond our control. All statements, other than statements of historical fact, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this report, the words “could,” “believe,” “anticipate,” “intend,” “estimate,” “expect,” “may,” “continue,” “predict,” “potential,” “project” and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. In particular, the factors discussed in this report and detailed under *Part II, Item 1A. Risk Factors* in this report and our Annual Report on Form 10–K for the year ended December 31, 2020 could affect our actual results and cause our actual results to differ materially from expectations, estimates or assumptions expressed, forecasted or implied in such forward-looking statements. Unless the context requires otherwise, references to “we,” “us,” “our” or the “Company” are intended to mean the business and operations of the Company and its consolidated subsidiaries.

Forward-looking statements may include statements about:

- the volatility of realized oil and natural gas prices;
- the implications and logistical challenges of epidemic or pandemic diseases, including the COVID-19 pandemic and its impact on the oil and natural gas industry, pricing and demand for oil and natural gas and supply chain logistics;
- logistical challenges and the supply chain disruptions;
- changes in general economic, business or industry conditions, including conditions of the U.S. oil and natural gas industry and the effect of U.S. energy, environmental, monetary and trade policies;
- conditions in the capital, financial and credit markets and our ability to obtain capital needed for development and exploration operations on favorable terms or at all;
- conditions of the U.S. oil and natural gas industry and the effect of U.S. energy, monetary and trade policies on our industry and business;
- our ability to execute our business and financial strategies;
- exploration and development drilling prospects, inventories, projects and programs;
- levels of production;
- the impact of reduced drilling activity on our exploration and development drilling prospects, inventories, projects and programs;
- regional supply and demand factors, any delays, curtailment delays or interruptions of production, and any governmental order, rule or regulation that may impose production limits;
- our ability to replace our oil and natural gas reserves;
- acquisitions and sales of assets and our anticipated synergies and cost savings from these transactions;
- competition in the oil and natural gas industry;
- uncertainties with respect to identified drilling locations and estimates of reserves;
- the impact of severe weather conditions on our production;
- our ability to comply with applicable governmental laws and regulations and to obtain permits and governmental approvals;
- our environmental initiatives and targets;
- future operating results;
- future dividends to our stockholders;
- impact of any impairment charges;
- lease operating expenses, general and administrative costs and finding and development costs;
- capital expenditure plans;
- use of proceeds from divestiture of assets;
- the conditions impacting the timing and amount of common stock repurchases under our common stock repurchase program;

- other plans, objectives, expectations and intentions; and
- certain other factors discussed elsewhere in this report.

All forward-looking statements speak only as of the date of this report or, if earlier, as of the date they were made. We do not intend to, and disclaim any obligation to, update or revise any forward-looking statements unless required by securities laws. You should not place undue reliance on these forward-looking statements. Moreover, we operate in a very competitive and rapidly changing environment. New risks emerge from time to time. It is not possible for our management to predict all risks, nor can we assess the impact of all factors on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements we may make. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this report are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved or occur, and actual results could differ materially and adversely from those anticipated or implied in the forward-looking statements.

PART I. FINANCIAL INFORMATION

ITEM 1. CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

Diamondback Energy, Inc. and Subsidiaries
Condensed Consolidated Balance Sheets
(Unaudited)

Assets	September 30, 2021	December 31, 2020
	(In millions, except par values and share data)	
Current assets:		
Cash and cash equivalents	$ 457	$ 104
Restricted cash	18	4
Accounts receivable:		
Joint interest and other, net	99	56
Oil and natural gas sales, net	712	281
Inventories	53	33
Derivative instruments	14	1
Income tax receivable	—	100
Assets held for sale	83	—
Prepaid expenses and other current assets	28	23
Total current assets	1,464	602
Property and equipment:		
Oil and natural gas properties, full cost method of accounting ($8,214 million and $7,493 million excluded from amortization at September 30, 2021 and December 31, 2020, respectively)	32,554	27,377
Midstream assets	922	1,013
Other property, equipment and land	164	138
Accumulated depletion, depreciation, amortization and impairment	(13,234)	(12,314)
Property and equipment, net	20,406	16,214
Funds held in escrow	66	51
Equity method investments	509	533
Derivative instruments	4	—
Deferred income taxes, net	25	73
Investment in real estate, net	89	101
Other assets	76	45
Total assets	$ 22,639	$ 17,619

See accompanying notes to condensed consolidated financial statements.

Diamondback Energy, Inc. and Subsidiaries
Condensed Consolidated Balance Sheets - (Continued)
(Unaudited)

Liabilities and Stockholders' Equity	September 30, 2021	December 31, 2020
	(In millions, except par values and share data)	
Current liabilities:		
Accounts payable - trade	$ 21	$ 71
Accrued capital expenditures	308	186
Current maturities of long-term debt	20	191
Other accrued liabilities	476	302
Revenues and royalties payable	561	237
Derivative instruments	610	249
Total current liabilities	1,996	1,236
Long-term debt	6,925	5,624
Derivative instruments	36	57
Asset retirement obligations	178	108
Deferred income taxes	1,068	783
Other long-term liabilities	14	7
Total liabilities	10,217	7,815
Commitments and contingencies (Note 13)		
Stockholders' equity:		
Common stock, $0.01 par value; 400,000,000 shares authorized; 180,791,028 and 158,088,182 shares issued and outstanding at September 30, 2021 and December 31, 2020, respectively	2	2
Additional paid-in capital	14,389	12,656
Retained earnings (accumulated deficit)	(2,908)	(3,864)
Total Diamondback Energy, Inc. stockholders' equity	11,483	8,794
Non-controlling interest	939	1,010
Total equity	12,422	9,804
Total liabilities and equity	$ 22,639	$ 17,619

See accompanying notes to condensed consolidated financial statements.

Diamondback Energy, Inc. and Subsidiaries
Condensed Consolidated Statements of Operations
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
	(In millions, except per share amounts, shares in thousands)			
Revenues:				
Oil sales	$ 1,506	$ 606	$ 3,845	$ 1,785
Natural gas sales	152	36	363	61
Natural gas liquid sales	239	65	528	156
Midstream services	12	12	35	37
Other operating income	1	1	4	5
Total revenues	1,910	720	4,775	2,044
Costs and expenses:				
Lease operating expenses	156	102	415	332
Production and ad valorem taxes	124	55	304	148
Gathering and transportation	67	33	154	105
Midstream services expense	19	26	70	81
Depreciation, depletion, amortization and accretion	341	288	955	1,041
Impairment of oil and natural gas properties	—	1,451	—	4,999
General and administrative expenses	38	20	99	64
Merger and integration expense	—	—	77	—
Other operating expense	1	1	11	4
Total costs and expenses	746	1,976	2,085	6,774
Income (loss) from operations	1,164	(1,256)	2,690	(4,730)
Other income (expense):				
Interest expense, net	(57)	(53)	(170)	(147)
Other income (expense), net	2	(2)	(4)	(8)
Gain (loss) on derivative instruments, net	(234)	(99)	(895)	82
Gain (loss) on sale of equity method investments	—	—	23	—
Gain (loss) on extinguishment of debt	(12)	(2)	(73)	(5)
Income (loss) from equity investments	4	3	6	(10)
Total other income (expense), net	(297)	(153)	(1,113)	(88)
Income (loss) before income taxes	867	(1,409)	1,577	(4,818)
Provision for (benefit from) income taxes	193	(304)	352	(902)
Net income (loss)	674	(1,105)	1,225	(3,916)
Net income (loss) attributable to non-controlling interest	25	8	45	(138)
Net income (loss) attributable to Diamondback Energy, Inc.	$ 649	$ (1,113)	$ 1,180	$ (3,778)
Earnings (loss) per common share:				
Basic	$ 3.59	$ (7.05)	$ 6.73	$ (23.91)
Diluted	$ 3.56	$ (7.05)	$ 6.68	$ (23.91)
Weighted average common shares outstanding:				
Basic	181,027	157,833	175,464	157,984
Diluted	182,149	157,833	176,553	157,984
Dividends declared per share	$ 0.50	$ 0.375	$ 1.35	$ 1.125

See accompanying notes to condensed consolidated financial statements.

Diamondback Energy, Inc. and Subsidiaries
Condensed Consolidated Statements of Stockholders' Equity
(Unaudited)

	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Non-Controlling Interest	Total
	($ in millions, shares in thousands)					
Balance December 31, 2020	158,088	$ 2	$ 12,656	$ (3,864)	$ 1,010	$ 9,804
Unit-based compensation	—	—	—	—	3	3
Distribution equivalent rights payments	—	—	—	(1)	—	(1)
Common units issued for acquisitions	22,795	—	1,727	—	—	1,727
Stock-based compensation	—	—	11	—	—	11
Cash paid for tax withholding on vested equity awards	—	—	(6)	—	—	(6)
Repurchased units under buyback programs	—	—	—	—	(24)	(24)
Distributions to non-controlling interest	—	—	—	—	(17)	(17)
Dividend paid	—	—	—	(68)	—	(68)
Exercise of stock options and issuance of restricted stock units and awards	101	—	—	—	—	—
Change in ownership of consolidated subsidiaries, net	—	—	(4)	—	4	—
Net income (loss)	—	—	—	220	3	223
Balance March 31, 2021	180,984	2	14,384	(3,713)	979	11,652
Unit-based compensation	—	—	—	—	3	3
Distribution equivalent rights payments	—	—	—	(1)	(1)	(2)
Stock-based compensation	—	—	15	—	—	15
Cash paid for tax withholding on vested equity awards	—	—	—	—	(2)	(2)
Repurchased units under buyback programs	—	—	—	—	(12)	(12)
Distributions to non-controlling interest	—	—	—	—	(24)	(24)
Dividend paid	—	—	—	(72)	—	(72)
Exercise of stock options and vesting of restricted stock units and awards	65	—	3	—	—	3
Change in ownership of consolidated subsidiaries, net	—	—	(3)	—	4	1
Net income (loss)	—	—	—	311	17	328
Balance June 30, 2021	181,049	2	14,399	(3,475)	964	11,890
Unit-based compensation	—	—	—	—	3	3
Distribution equivalent rights payments	—	—	—	—	(1)	(1)
Stock-based compensation	—	—	17	—	—	17
Repurchased shares under buyback program	(268)	—	(22)	—	—	(22)
Repurchased units under buyback programs	—	—	—	—	(27)	(27)
Distributions to non-controlling interest	—	—	—	—	(31)	(31)
Dividend paid	—	—	—	(82)	—	(82)
Exercise of stock options and vesting of restricted stock units and awards	10	—	1	—	—	1
Change in ownership of consolidated subsidiaries, net	—	—	(6)	—	6	—
Net income (loss)	—	—	—	649	25	674
Balance September 30, 2021	180,791	$ 2	$ 14,389	$ (2,908)	$ 939	$ 12,422

See accompanying notes to condensed consolidated financial statements.

Diamondback Energy, Inc. and Subsidiaries
Condensed Consolidated Statements of Stockholders' Equity - (Continued)
(Unaudited)

	Common Stock		Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Non-Controlling Interest	Total
	Shares	Amount				
	($ in millions, shares in thousands)					
Balance December 31, 2019	159,002	$ 2	$ 12,357	$ 890	$ 1,657	$ 14,906
Unit-based compensation	—	—	—	—	5	5
Distribution equivalent rights payments	—	—	—	—	(1)	(1)
Stock-based compensation	—	—	10	—	—	10
Cash paid for tax withholding on vested equity awards	—	—	(5)	—	—	(5)
Repurchased shares for share buyback program	(1,280)	—	(98)	—	—	(98)
Distribution to non-controlling interest	—	—	—	—	(43)	(43)
Dividend paid	—	—	—	(59)	—	(59)
Exercise of stock options and vesting of restricted stock units	93	—	1	—	—	1
Net income (loss)	—	—	—	(272)	(128)	(400)
Balance March 31, 2020	157,815	2	12,265	559	1,490	14,316
Distribution equivalent rights payments	—	—	—	—	(1)	(1)
Stock-based compensation	—	—	11	—	—	11
Repurchased shares for share buyback program	—	—	—	—	(2)	(2)
Distribution to non-controlling interest	—	—	—	—	(19)	(19)
Dividend paid	—	—	—	(59)	—	(59)
Exercise of stock options and vesting of restricted stock units	9	—	—	—	—	—
Change in ownership of consolidated subsidiaries, net	—	—	329	—	(329)	—
Net income (loss)	—	—	—	(2,393)	(18)	(2,411)
Balance June 30, 2020	157,824	2	12,605	(1,893)	1,121	11,835
Unit-based compensation	—	—	—	—	3	3
Stock-based compensation	—	—	10	—	—	10
Cash paid for tax withholding on vested equity awards	—	—	—	—	—	—
Distribution to non-controlling interest	—	—	—	—	(15)	(15)
Dividend paid	—	—	—	(59)	—	(59)
Exercise of stock options and vesting of restricted stock units	26	—	—	—	—	—
Net income (loss)	—	—	—	(1,113)	8	(1,105)
Balance September 30, 2020	157,850	$ 2	$ 12,615	$ (3,065)	$ 1,117	$ 10,669

See accompanying notes to condensed consolidated financial statements.

Diamondback Energy, Inc. and Subsidiaries
Condensed Consolidated Statements of Cash Flows
(Unaudited)

	Nine Months Ended September 30,	
	2021	2020
	(In millions)	
Cash flows from operating activities:		
Net income (loss)	$ 1,225	$ (3,916)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:		
Provision for (benefit from) deferred income taxes	348	(840)
Impairment of oil and natural gas properties	—	4,999
Depreciation, depletion, amortization and accretion	955	1,041
(Gain) loss on extinguishment of debt	73	5
(Gain) loss on derivative instruments, net	895	(82)
Cash received (paid) on settlement of derivative instruments	(847)	288
Equity-based compensation expense	37	27
(Gain) loss on sale of equity method investments	(23)	—
Other	39	31
Changes in operating assets and liabilities:		
Accounts receivable	(307)	265
Income tax receivable	152	(62)
Prepaid expenses and other	23	(1)
Accounts payable and accrued liabilities	(39)	(18)
Revenues and royalties payable	257	(59)
Other	(11)	37
Net cash provided by (used in) operating activities	2,777	1,715
Cash flows from investing activities:		
Drilling, completions and infrastructure additions to oil and natural gas properties	(1,030)	(1,500)
Additions to midstream assets	(23)	(133)
Property acquisitions	(438)	(154)
Proceeds from sale of assets	112	2
Contributions to equity method investments	(7)	(90)
Distributions from equity method investments	9	27
Other	54	(7)
Net cash provided by (used in) investing activities	(1,323)	(1,855)
Cash flows from financing activities:		
Proceeds from borrowings under credit facilities	759	917
Repayments under credit facilities	(853)	(1,238)
Proceeds from senior notes	2,200	997
Repayment of senior notes	(2,540)	(239)
Premium on extinguishment of debt	(178)	(2)
Proceeds from (repayments to) joint venture	(14)	47
Repurchased shares under buyback program	(22)	(98)
Repurchased units under buyback program	(63)	—
Dividends to stockholders	(221)	(177)
Distributions to non-controlling interest	(72)	(77)
Financing portion of net cash received (paid) for derivative instruments	25	—
Other	(42)	(19)
Net cash provided by (used in) financing activities	(1,021)	111
Net increase (decrease) in cash and cash equivalents	433	(29)
Cash, cash equivalents and restricted cash at beginning of period	108	128
Cash, cash equivalents and restricted cash at end of period(1)	$ 541	$ 99
Supplemental disclosure of non-cash transactions:		
Accrued capital expenditures included in accounts payable and accrued expenses	$ 269	$ 352
Common stock issued for business combinations	$ 1,727	$ —

(1) See Note 2—Summary of Significant Accounting Policies

See accompanying notes to condensed consolidated financial statements.

Diamondback Energy, Inc. and Subsidiaries
Condensed Notes to Consolidated Financial Statements
(Unaudited)

1. DESCRIPTION OF THE BUSINESS AND BASIS OF PRESENTATION

Organization and Description of the Business

Diamondback Energy, Inc., together with its subsidiaries (collectively referred to as “Diamondback” or the “Company” unless the context otherwise requires), is an independent oil and natural gas company currently focused on the acquisition, development, exploration and exploitation of unconventional, onshore oil and natural gas reserves in the Permian Basin in West Texas.

As of September 30, 2021, the wholly owned subsidiaries of Diamondback include Diamondback E&P LLC (Diamondback E&P), a Delaware limited liability company, Viper Energy Partners GP LLC, a Delaware limited liability company, Rattler Midstream GP LLC, a Delaware limited liability company, and QEP Resources, Inc. (“QEP”), a Delaware corporation. Diamondback O&G LLC (“O&G”), Energen Corporation (“Energen”), Energen Resources Corporation and EGN Services, Inc., former wholly owned subsidiaries of Diamondback, were merged with and into Diamondback E&P LLC effective June 30, 2021 as part of the internal restructuring of the Company’s subsidiaries (the “E&P Merger”).

Basis of Presentation

The condensed consolidated financial statements include the accounts of the Company and its subsidiaries after all significant intercompany balances and transactions have been eliminated upon consolidation.

Diamondback’s publicly traded subsidiaries Viper Energy Partners LP (“Viper”) and Rattler Midstream LP (“Rattler”) are consolidated in the Company’s financial statements. As of September 30, 2021, the Company owned approximately 59% of Viper’s total units outstanding. The Company’s wholly owned subsidiary, Viper Energy Partners GP LLC, is the general partner of Viper. As of September 30, 2021, the Company owned approximately 73% of Rattler’s total units outstanding. The Company’s wholly owned subsidiary, Rattler Midstream GP LLC, is the general partner of Rattler. The results of operations attributable to the non-controlling interest in Viper and Rattler are presented within equity and net income and are shown separately from the Company’s equity and net income attributable to the Company.

These condensed consolidated financial statements have been prepared by the Company without audit, pursuant to the rules and regulations of the SEC. They reflect all adjustments that are, in the opinion of management, necessary for a fair statement of the results for interim periods, on a basis consistent with the annual audited financial statements. All such adjustments are of a normal recurring nature. Certain information, accounting policies and footnote disclosures normally included in financial statements prepared in accordance with GAAP have been omitted pursuant to SEC rules and regulations, although the Company believes the disclosures are adequate to make the information presented not misleading. This Quarterly Report on Form 10–Q should be read in conjunction with the Company’s most recent Annual Report on Form 10–K for the fiscal year ended December 31, 2020, which contains a summary of the Company’s significant accounting policies and other disclosures.

Reclassifications

Certain prior period amounts have been reclassified to conform to the current period financial statement presentation. These reclassifications had an immaterial effect on the previously reported total assets, total liabilities, stockholders’ equity, results of operations or cash flows.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

Certain amounts included in or affecting the Company’s consolidated financial statements and related disclosures must be estimated by management, requiring certain assumptions to be made with respect to values or conditions that cannot be known with certainty at the time the consolidated financial statements are prepared. These estimates and assumptions affect the amounts the Company reports for assets and liabilities and the Company’s disclosure of contingent assets and liabilities as of the date of the consolidated financial statements. Actual results could differ from those estimates.

Making accurate estimates and assumptions is particularly difficult in the oil and natural gas industry, given the challenges resulting from volatility in oil and natural gas prices. For instance, in 2020, the effects of COVID-19 and actions by OPEC members and other exporting nations on the supply and demand in global oil and natural gas markets resulted in significant negative pricing pressures in the first half of 2020, followed by a recovery in pricing and an increase in demand in the second half of 2020 and into 2021. However, the COVID-19 Delta variant emerged in March 2021 and became highly transmissible in July 2021, which contributed to additional pricing volatility during the third quarter of 2021. The financial results of companies in the oil and natural gas industry have been impacted materially as a result of changing market conditions. Such circumstances generally increase the uncertainty in the Company's accounting estimates, particularly those involving financial forecasts.

The Company evaluates these estimates on an ongoing basis, using historical experience, consultation with experts and other methods the Company considers reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from the Company's estimates. Any effects on the Company's business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known. Significant items subject to such estimates and assumptions include estimates of proved oil and natural gas reserves and related present value estimates of future net cash flows therefrom, the carrying value of oil and natural gas properties, asset retirement obligations, the fair value determination of acquired assets and liabilities assumed, equity-based compensation, fair value estimates of derivative instruments and estimates of income taxes.

Cash, Cash Equivalents and Restricted Cash

The following table provides a reconciliation of cash, cash equivalents and restricted cash as reported at the end of the period in the condensed consolidated statements of cash flows for the nine months ended September 30, 2021 and 2020 to the line items within the condensed consolidated balance sheets:

	Nine Months Ended September 30,	
	2021	2020
	(In millions)	
Cash and cash equivalents	$ 457	$ 92
Restricted cash	18	7
Restricted cash included in funds held in escrow(1)	66	—
Total cash, cash equivalents and restricted cash	$ 541	$ 99

(1) As of September 30, 2021, the restricted cash included in funds held in escrow on the condensed consolidated balance sheet is related to cash deposited into escrow accounts for a title dispute between outside parties in the Williston Basin and an escrow deposit related to Viper's Swallowtail Acquisition, as defined in Note 14—Subsequent Events.

Recent Accounting Pronouncements

Recently Adopted Pronouncements

In December 2019, the FASB issued ASU 2019-12, "Income Taxes (Topic 740) - Simplifying the Accounting for Income Taxes." This update is intended to simplify the accounting for income taxes by removing certain exceptions and by clarifying and amending existing guidance and is effective for public business entities beginning after December 15, 2020 with early adoption permitted. The Company adopted this update effective January 1, 2021. The adoption of this update did not have a material impact on its financial position, results of operations or liquidity.

Accounting Pronouncements Not Yet Adopted

In October 2021, the FASB issued ASU 2021-08, "Business Combinations (Topic 805) – Accounting for Contract Assets and Contract Liabilities from Contracts with Customers." This update requires the acquirer in a business combination to record contract asset and liabilities following Topic 606 – "Revenue from Contracts with Customers" at acquisition as if it had originated the contract, rather than at fair value. This update is effective for public business entities beginning after December 15, 2022 with early adoption permitted. The Company continues to evaluate the provisions of this update, but does not believe the adoption will have a material impact on its financial position, results of operations or liquidity.

The Company considers the applicability and impact of all ASUs. ASUs not discussed above were assessed and determined to be either not applicable, the effects of adoption are not expected to be material or are clarifications of ASUs previously disclosed.

3. REVENUE FROM CONTRACTS WITH CUSTOMERS

Revenue from Contracts with Customers

Sales of oil, natural gas and natural gas liquids are recognized at the point control of the product is transferred to the customer. Virtually all of the pricing provisions in the Company's contracts are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, the quality of the oil or natural gas and the prevailing supply and demand conditions. As a result, the price of the oil, natural gas and natural gas liquids fluctuates to remain competitive with other available oil, natural gas and natural gas liquids supplies. The following tables present the Company's revenue from contracts with customers disaggregated by product type and basin:

	Three Months Ended September 30, 2021				Three Months Ended September 30, 2020			
	Midland Basin	Delaware Basin	Other	Total	Midland Basin	Delaware Basin	Other	Total
	(In millions)							
Oil sales	$ 983	$ 419	$ 104	$ 1,506	$ 348	$ 257	$ 1	$ 606
Natural gas sales	91	57	4	152	19	17	—	36
Natural gas liquid sales	150	73	16	239	36	28	1	65
Total	$ 1,224	$ 549	$ 124	$ 1,897	$ 403	$ 302	$ 2	$ 707

	Nine Months Ended September 30, 2021				Nine Months Ended September 30, 2020			
	Midland Basin	Delaware Basin	Other	Total	Midland Basin	Delaware Basin	Other	Total
	(In millions)							
Oil sales	$ 2,428	$ 1,185	$ 232	$ 3,845	$ 1,030	$ 750	$ 5	$ 1,785
Natural gas sales	207	145	11	363	32	29	—	61
Natural gas liquid sales	327	172	29	528	88	67	1	156
Total	$ 2,962	$ 1,502	$ 272	$ 4,736	$ 1,150	$ 846	$ 6	$ 2,002

4. ACQUISITIONS AND DIVESTITURES

Guidon Operating LLC

On December 21, 2020, the Company entered into a definitive purchase agreement to acquire all leasehold interests and related assets of Guidon Operating LLC (the "Guidon Acquisition") which include approximately 32,500 net acres in the Northern Midland Basin in exchange for 10.68 million shares of the Company's common stock and $375 million of cash. The Guidon Acquisition closed on February 26, 2021. The cash portion of this transaction was funded through a combination of cash on hand and borrowings under the Company's credit facility. As a result of the Guidon Acquisition, the Company added approximately 210 gross producing wells.

The following table presents the acquisition consideration paid in the Guidon Acquisition (in millions, except per share data, shares in thousands):

Consideration:	
Shares of Diamondback common stock issued at closing	10,676
Closing price per share of Diamondback common stock on the closing date	$ 69.28
Fair value of Diamondback common stock issued	$ 740
Cash consideration	375
Total consideration (including fair value of Diamondback common stock issued)	$ 1,115

Purchase Price Allocation

The Guidon Acquisition has been accounted for as a business combination using the acquisition method. The following table represents the allocation of the total purchase price paid in the Guidon Acquisition to the identifiable assets acquired based on the fair values at the acquisition date, with any excess of the purchase price over the estimated fair value of the identifiable net assets acquired. Although the purchase price allocation is substantially complete as of the date of this filing, there may be further adjustments to the fair value of certain assets acquired and liabilities assumed, including but not limited to the Company's oil and natural gas properties. The Company expects to complete the purchase price allocation during the 12-month period following the acquisition date and may revise the value of the assets and liabilities as appropriate within that time frame. Through September 30, 2021, there have been no material changes to the allocation presented in the March 31, 2021 10-Q filed with the SEC on May 7, 2021.

The following table sets forth the Company's preliminary purchase price allocation (in millions):

Total consideration	$	1,115
Fair value of liabilities assumed:		
Asset retirement obligations		9
Fair value of assets acquired:		
Oil and gas properties		1,110
Midstream assets		14
Amount attributable to assets acquired		1,124
Net assets acquired and liabilities assumed	$	1,115

Oil and natural gas properties were valued using an income approach utilizing the discounted cash flow method, which takes into account production forecasts, projected commodity prices and pricing differentials, and estimates of future capital and operating costs which were then discounted utilizing an estimated weighted-average cost of capital for industry market participants. The fair value of acquired midstream assets was based on the cost approach, which utilized asset listings and cost records with consideration for the reported age, condition, utilization and economic support of the assets. The majority of the measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and are therefore considered Level 3 inputs.

With the completion of the Guidon Acquisition, the Company acquired proved properties of $537 million and unproved properties of $573 million. The results of operations attributable to the Guidon Acquisition since the acquisition date have been included in the condensed consolidated statements of operations and include $107 million and $240 million of total revenue for the three and nine months ended September 30, 2021, respectively, and $52 million and $117 million of net income for the three and nine months ended September 30, 2021, respectively.

QEP Resources, Inc.

On March 17, 2021, the Company completed its acquisition of QEP in an all-stock transaction (the "QEP Merger"). The addition of QEP's assets increased the Company's net acreage in the Midland Basin by approximately 49,000 net acres. Under the terms of the QEP Merger, each eligible share of QEP common stock issued and outstanding immediately prior to the effective time converted into the right to receive 0.050 of a share of Diamondback common stock, with cash being paid in lieu of any fractional shares (the "merger consideration"). At the closing date of the QEP Merger, the carrying value of QEP's outstanding debt was approximately $1.6 billion. See Note 7—Debt for further discussion.

The following table presents the acquisition consideration paid to QEP stockholders in the QEP Merger (in millions, except per share data, shares in thousands):

Consideration:		
Eligible shares of QEP common stock converted into shares of Diamondback common stock		238,153
Shares of QEP equity awards included in precombination consideration		4,221
Total shares of QEP common stock eligible for merger consideration		242,374
Exchange ratio		0.050
Shares of Diamondback common stock issued as merger consideration		12,119
Closing price per share of Diamondback common stock	$	81.41
Total consideration (fair value of the Company's common stock issued)	$	987

Purchase Price Allocation

The QEP Merger has been accounted for as a business combination using the acquisition method. The following table represents the preliminary allocation of the total purchase price for the acquisition of QEP to the identifiable assets acquired and the liabilities assumed based on the fair values at the acquisition date, with any excess of the purchase price over the estimated fair value of the identifiable net assets acquired. Although the purchase price allocation is substantially complete as of the date of this filing, certain data necessary to complete the purchase price allocation is not yet available, and includes, but is not limited to, final tax returns that provide the underlying tax basis of QEP's assets and liabilities. As such, there may be further adjustments to the fair value of certain assets acquired and liabilities assumed, including the Company's oil and natural gas properties. The Company expects to complete the purchase price allocation during the 12-month period following the acquisition date. Through September 30, 2021, there have been no material changes to the allocation presented in the March 31, 2021 10-Q filed with the SEC on May 7, 2021.

The following table sets forth the Company's preliminary purchase price allocation (in millions):

Total consideration	$	987
Fair value of liabilities assumed:		
Accounts payable - trade	$	26
Accrued capital expenditures		38
Other accrued liabilities		108
Revenues and royalties payable		67
Derivative instruments		242
Long-term debt		1,710
Asset retirement obligations		54
Other long-term liabilities		47
Amount attributable to liabilities assumed	$	2,292
Fair value of assets acquired:		
Cash, cash equivalents and restricted cash	$	22
Accounts receivable - joint interest and other, net		87
Accounts receivable - oil and natural gas sales, net		44
Inventories		18
Income tax receivable		33
Prepaid expenses and other current assets		7
Oil and natural gas properties		2,936
Other property, equipment and land		9
Deferred income taxes		17
Other assets		106
Amount attributable to assets acquired		3,279
Net assets acquired and liabilities assumed	$	987

The purchase price allocation above was based on preliminary estimates of the fair values of the assets and liabilities of QEP as of the closing date of the QEP Merger. The majority of the measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and are therefore considered Level 3 inputs. The fair value of acquired property and equipment, including midstream assets classified in oil and natural gas properties, is based on the cost approach, which utilized asset listings and cost records with consideration for the reported age, condition, utilization and economic support of the assets. Oil and natural gas properties were valued using an income approach utilizing the discounted cash flow method, which takes into account production forecasts, projected commodity prices and pricing differentials, and estimates of future capital and operating costs which were then discounted utilizing an estimated weighted-average cost of capital for industry market participants. The fair value of QEP's outstanding senior unsecured notes was based on unadjusted quoted prices in an active market, which are considered Level 1 inputs. The value of derivative instruments was based on observable inputs including forward commodity-price curves which are considered Level 2 inputs. Deferred income taxes represent the tax effects of differences in the tax basis and merger-date fair values of assets acquired and liabilities assumed.

With the completion of the QEP Merger, the Company acquired proved properties of $2.3 billion and unproved properties of $442 million, primarily in the Midland Basin and the Williston Basin. The results of operations attributable to the QEP Merger since the acquisition date have been included in the condensed consolidated statements of operations and include $422 million and $835 million of total revenue, and $162 million and $301 million of net income for the three and nine months ended September 30, 2021, respectively.

Pro Forma Financial Information

The following unaudited summary pro forma financial information for the three and nine months ended September 30, 2021 and 2020 has been prepared to give effect to the QEP Merger and the Guidon Acquisition as if they had occurred on January 1, 2020. The unaudited pro forma financial information does not purport to be indicative of what the combined company's results of operations would have been if these transactions had occurred on the dates indicated, nor is it indicative of the future financial position or results of operations of the combined company.

The below information reflects pro forma adjustments for the issuance of the Company's common stock in exchange for QEP's outstanding shares of common stock, as well as pro forma adjustments based on available information and certain assumptions that the Company believes are reasonable, including adjustments to depreciation, depletion and amortization based on the full cost method of accounting and the purchase price allocated to property, plant, and equipment as well as adjustments to interest expense and the provision for (benefit from) income taxes.

Additionally, pro forma earnings were adjusted to exclude acquisition-related costs incurred by the Company for the QEP Merger and the Guidon Acquisition of approximately $77 million for the nine months ended September 30, 2021 and acquisition-related costs incurred by QEP of $31 million through the closing date of the QEP Merger. These acquisition-related costs primarily consist of one-time severance costs and the accelerated or change-in-control vesting of certain QEP share-based awards for former QEP employees based on the terms of the merger agreement relating to the QEP Merger and other bank, legal and advisory fees. The pro forma results of operations do not include any cost savings or other synergies that may result from the QEP Merger and the Guidon Acquisition or any estimated costs that have been or will be incurred by the Company to integrate the acquired assets. The pro forma financial data does not include the results of operations for any other acquisitions made during the periods presented, as they were primarily acreage acquisitions and their results were not deemed material.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
	(In millions, except per share amounts)			
Revenues	$ 1,910	$ 942	$ 5,047	$ 2,705
Income (loss) from operations	$ 1,164	$ (1,244)	$ 2,870	$ (4,780)
Net income (loss)	$ 649	$ (1,124)	$ 1,183	$ (3,593)
Basic earnings (loss) per common share	$ 3.59	$ (6.22)	$ 6.54	$ (19.88)
Diluted earnings (loss) per common share	$ 3.56	$ (6.22)	$ 6.50	$ (19.88)

Divestitures

On June 3, 2021 and June 7, 2021, respectively, the Company closed transactions to divest certain non-core Permian assets including over 7,000 net acres of non-core Southern Midland Basin acreage in Upton county, Texas and approximately 1,300 net acres of non-core, non-operated Delaware Basin assets in Lea county, New Mexico for a combined sales price of $82 million, net of customary purchase price adjustments. These assets have estimated full year 2021 net production of approximately 900 BO/d (2,650 BOE/d) from 140 producing wells. The Company used its net proceeds from these transactions toward debt reduction.

See Note 14—Subsequent Events for further discussion of acquisitions and divestitures in the fourth quarter of 2021.

5. PROPERTY AND EQUIPMENT

Property and equipment includes the following as of the dates indicated:

	September 30, 2021	December 31, 2020
	(In millions)	
Oil and natural gas properties:		
Subject to depletion	$ 24,340	$ 19,884
Not subject to depletion	8,214	7,493
Gross oil and natural gas properties	32,554	27,377
Accumulated depletion	(5,136)	(4,237)
Accumulated impairment	(7,954)	(7,954)
Oil and natural gas properties, net	19,464	15,186
Midstream assets	922	1,013
Other property, equipment and land	164	138
Accumulated depreciation and impairment	(144)	(123)
Total property and equipment, net	$ 20,406	$ 16,214

Under the full cost method of accounting, the Company is required to perform a ceiling test each quarter which determines a limit, or ceiling, on the book value of proved oil and natural gas properties. No impairment expense was recorded for the three and nine months ended September 30, 2021. The Company recorded $1.5 billion and $5.0 billion in impairment expense for the three and nine months ended September 30, 2020, respectively, based on the results of the respective quarterly ceiling tests.

In connection with the QEP Merger and the Guidon Acquisition, the Company recorded the oil and natural gas properties acquired at fair value, based on forward strip oil and natural gas pricing existing at the closing date of the respective transactions, in accordance with ASC 820 Fair Value Measurement. Pursuant to SEC guidance, the Company determined that the fair value of the properties acquired in the QEP Merger and the Guidon Acquisition clearly exceeded the related full cost ceiling limitation beyond a reasonable doubt. As such, the Company requested and received a waiver from the SEC to exclude the properties acquired from the ceiling test calculation for the quarter ended March 31, 2021. As a result, no impairment expense related to the QEP Merger and the Guidon Acquisition was recorded for the three months ended March 31, 2021. Had the Company not received a waiver from the SEC, an impairment charge of approximately $1.1 billion would have been recorded for such period. Management affirmed there has not been a decline in the fair value of these acquired assets. The properties acquired in the QEP Merger and the Guidon Acquisition had total unamortized costs at March 31, 2021 of $3.0 billion and $1.1 billion, respectively.

In addition to commodity prices, the Company's production rates, levels of proved reserves, future development costs, transfers of unevaluated properties and other factors will determine its actual ceiling test calculation and impairment analysis in future periods. If the future trailing 12-month commodity prices decline as compared to the commodity prices used in prior quarters, the Company may have material write downs in subsequent quarters. It is possible that circumstances requiring additional impairment testing will occur in future interim periods, which could result in potentially material impairment charges being recorded.

6. ASSET RETIREMENT OBLIGATIONS

The following table describes the changes to the Company's asset retirement obligations liability for the following periods:

	Nine Months Ended September 30,	
	2021	2020
	(In millions)	
Asset retirement obligations, beginning of period	$ 109	$ 94
Additional liabilities incurred	9	12
Liabilities acquired	64	3
Liabilities settled and divested	(17)	(1)
Accretion expense	7	5
Revisions in estimated liabilities	13	—
Asset retirement obligations, end of period	185	113
Less current portion[(1)]	7	1
Asset retirement obligations - long-term	$ 178	$ 112

(1) The current portion of the asset retirement obligation is included in other accrued liabilities in the Company's condensed consolidated balance sheets.

7. DEBT

Long-term debt consisted of the following as of the dates indicated:

	September 30, 2021	December 31, 2020
	(In millions)	
4.625% Notes due 2021	$ —	$ 191
5.375% Senior Notes due 2022[(1)]	25	—
7.320% Medium-term Notes, Series A, due 2022	20	20
0.900% Senior Notes due 2023[(2)]	650	—
5.250% Senior Notes due 2023[(1)]	10	—
2.875% Senior Notes due 2024	1,000	1,000
4.750% Senior Notes due 2025	500	500
5.375% Senior Notes due 2025	—	800
3.250% Senior Notes due 2026	800	800
5.625% Senior Notes due 2026[(1)]	18	—
7.125% Medium-term Notes, Series B, due 2028	100	100
3.500% Senior Notes due 2029	1,200	1,200
3.125% Senior Notes due 2031	900	—
4.400% Senior Notes due 2051	650	—
DrillCo Agreement[(3)]	65	79
Unamortized debt issuance costs	(35)	(29)
Unamortized discount costs	(29)	(27)
Unamortized premium costs	9	15
Fair value of interest rate swap agreements[(4)]	(10)	—
Revolving credit facility	—	23
Viper revolving credit facility	92	84
Viper 5.375% Senior Notes due 2027	480	480
Rattler revolving credit facility	—	79
Rattler 5.625% Senior Notes due 2025	500	500
Total debt, net	6,945	5,815
Less: current maturities of long-term debt	(20)	(191)
Total long-term debt	$ 6,925	$ 5,624

(1) At the effective time of the QEP Merger, QEP became a wholly owned subsidiary of the Company and remained the issuer of the notes.
(2) See Note 14—Subsequent Events for further discussion of the redemption of the 0.900% Senior Notes due 2023 in the fourth quarter of 2021.
(3) The Company entered into a participation and development agreement (the "DrillCo Agreement"), dated September 10, 2018, with Obsidian Resources, L.L.C. ("CEMOF") to fund oil and natural gas development. As of September 30, 2021, the amount due to CEMOF related to this alliance was $65 million.
(4) The Company has two interest rate swap agreements in place on the Company's $1.2 billion 3.500% fixed rate senior notes due 2029. See Note 11—Derivatives for additional information on the Company's interest rate swaps designated as fair value hedges.

References in this section to the Company shall mean Diamondback Energy, Inc. and Diamondback E&P, collectively, unless otherwise specified.

Second Amended and Restated Credit Facility

On June 2, 2021, Diamondback Energy, Inc., as parent guarantor, and O&G, as borrower (the "Borrower"), entered into a twelfth amendment (the "Amendment") to the Second Amended and Restated Credit Agreement, dated as of November 1, 2013, with Wells Fargo Bank, National Association, as administrative agent (the "Administrative Agent"), and the lenders party thereto (as amended, supplemented or otherwise modified to the date thereof and as further amended by the Amendment). The Amendment, among other things, (i) extended the maturity date to June 2, 2026, which may be further extended by two one-year extensions pursuant to the terms set forth in the credit agreement, (ii) decreased the total revolving loan commitments from $2.0 billion to $1.6 billion, which may be increased in an amount up to $1.0 billion (for a total maximum commitment amount of $2.6 billion) upon election of the Borrower (subject to obtaining additional lender commitments and satisfaction of customary conditions) pursuant to the terms set forth in the credit agreement, (iii) added the ability of the Borrower to incur up to $100 million of the loans under the credit agreement as swingline loans and (iv) changed the interest rate applicable to the loans and certain fees payable under the credit agreement. Outstanding borrowings under the credit agreement bear interest at a per annum rate elected by the Borrower that is equal to an alternate base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.50%, and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. After giving effect to the Amendment, (i) the applicable margin ranges from 0.250% to 1.125% per annum in the case of the alternate base rate, and from 1.250% to 2.125% per annum in the case of LIBOR, in each case based on the pricing level, and (ii) the commitment fee ranges from 0.150% to 0.350% per annum on the average daily unused portion of the commitments, based on the pricing level. The pricing level depends on certain ratings agencies' ratings of the Company's long-term senior unsecured debt.

On June 30, 2021, Diamondback E&P, as successor borrower, Diamondback Energy, Inc., as parent guarantor, and the Administrative Agent entered into a Successor Borrower Joinder Agreement (the "Joinder Agreement") in connection with the E&P Merger. Pursuant to the Joinder Agreement, Diamondback E&P assumed all obligations (including, without limitation, all of the indebtedness) of O&G as the borrower under the credit agreement, the Second Amended and Restated Guaranty Agreement, dated as of November 20, 2019, made by O&G and Diamondback Energy, Inc., and the other documents entered into connection therewith.

As of September 30, 2021, the maximum credit amount available under the credit agreement was $1.6 billion which was fully available for future borrowings, except for an aggregate of $3 million in outstanding letters of credit, which reduce available borrowings under the credit agreement on a dollar for dollar basis. There were no borrowings outstanding under the credit agreement during the three months ended September 30, 2021. During the three months ended September 30, 2020, the weighted average interest rate on borrowings under the credit agreement was 1.83%. During the nine months ended September 30, 2021 and 2020, the weighted average interest rate on borrowings under the credit agreement was 1.67% and 2.27%, respectively.

As of September 30, 2021, the Company was in compliance with all financial maintenance covenants under the credit agreement.

March 2021 Notes Offering

On March 24, 2021, Diamondback Energy, Inc. issued $650 million aggregate principal amount of 0.900% Senior Notes due March 24, 2023 (the "2023 Notes"), $900 million aggregate principal amount of 3.125% Senior Notes due March 24, 2031 (the "2031 Notes") and $650 million aggregate principal amount of 4.400% Senior Notes due March 24, 2051 (the "2051 Notes" and together with the 2023 Notes and the 2031 Notes, the "March 2021 Notes") and received proceeds, net of $24 million in debt issuance costs and discounts, of $2.18 billion. The net proceeds were primarily used to fund the repurchase of other senior notes outstanding as discussed further below. Interest on the March 2021 Notes is payable semi-annually in March and September, beginning in September 2021.

The March 2021 Notes are the Company's senior unsecured obligations and are fully and unconditionally guaranteed by Diamondback E&P. The March 2021 Notes are senior in right of payment to any of the Company's future subordinated indebtedness and rank equal in right of payment with all of the Company's existing and future senior indebtedness. The March 2021 Notes are effectively subordinated to the Company's existing and future secured indebtedness, if any, to the extent of the value of the collateral securing such indebtedness, and structurally subordinated to all of the existing and future indebtedness and other liabilities of the Company's subsidiaries other than Diamondback E&P.

Diamondback Energy, Inc. and Subsidiaries
Condensed Notes to Consolidated Financial Statements - (Continued)
(Unaudited)

The Company may not redeem the 2023 Notes in whole or in part at any time prior to September 24, 2021. The Company may redeem (i) the 2031 Notes in whole or in part at any time prior to December 24, 2030 and (ii) the 2051 Notes in whole or in part at any time prior to September 24, 2050, in each case at the redemption price set forth in the 2019 Indenture. If the March 2021 Notes are redeemed on or after the dates noted above, in each case, the March 2021 Notes may be redeemed at a redemption price equal to 100% of the principal amount of the March 2021 Notes to be redeemed plus interest accrued thereon to but not including the redemption date.

Upon the occurrence of a change of control triggering event as defined in the 2019 Indenture, holders may require the Company to purchase some or all of their March 2021 Notes for cash at a price equal to 101% of the principal amount of the March 2021 Notes being purchased, plus accrued and unpaid interest, if any, to the date of purchase.

Repurchases of Notes

On March 17, 2021, at the time of the QEP Merger discussed in Note 4—Acquisitions and Divestitures, QEP had outstanding debt at fair values consisting of $478 million of 5.375% Senior Notes due 2022 (the "QEP 2022 Notes"), $673 million of 5.250% Senior Notes due 2023 (the "QEP 2023 Notes") and $558 million of 5.625% Senior Notes due 2026 (the "QEP 2026 Notes" and together with the QEP 2022 Notes and QEP 2023 Notes, the "QEP Notes").

Subsequent to the QEP Merger, in March 2021, the Company repurchased pursuant to tender offers commenced by the Company, approximately $1.65 billion in fair value carrying amount of the QEP Notes for total cash consideration of $1.7 billion, including redemption and early premium fees of $152 million, which resulted in a loss on extinguishment of debt during the nine months ended September 30, 2021 of approximately $47 million. The aggregate fair value of the QEP Notes repurchased consisted of (i) $453 million, or 94.65%, of the outstanding fair value carrying amount of the QEP 2022 Notes, (ii) $663 million, or 98.43%, of the outstanding fair value carrying amount of the QEP 2023 Notes and (iii) $538 million, or 96.35%, of the outstanding fair value carrying amount of the QEP 2026 Notes.

In March 2021, the Company also repurchased an aggregate of $368 million principal amount of its 5.375% 2025 Senior Notes representing approximately 45.97% of the outstanding 2025 Senior Notes, for total cash consideration of $381 million, including redemption and early premium fees of $13 million. This resulted in a loss on extinguishment of debt during the nine months ended September 30, 2021 of $14 million. The Company funded the repurchases of the QEP Notes and 2025 Senior Notes with the proceeds from the March 2021 Notes offering discussed above.

In connection with the tender offers to repurchase the QEP Notes discussed above, the Company also solicited consents from holders of the QEP Notes to amend the indenture for the QEP Notes to, among other things, eliminate substantially all of the restrictive covenants and related provisions and certain events of default contained in the indenture under which the QEP Notes were issued. The Company received the requisite number of consents and, on March 23, 2021, entered into a supplemental indenture relating to the QEP Notes adopting these amendments.

In June 2021, the Company redeemed the remaining $191 million principal amount of the outstanding Energen 4.625% senior notes due on September 1, 2021. The Company recorded an immaterial pre-tax loss on extinguishment of debt related to the redemption, which included the write-off of unamortized debt discounts associated with the redeemed notes. The Company funded the redemption with internally generated cash flow from operations as well as proceeds from the divestitures of certain non-core assets as discussed in Note 4—Acquisitions and Divestitures.

In August 2021, the Company redeemed the remaining $432 million principal amount of its outstanding 5.375% 2025 Senior Notes for total cash consideration of $449 million, including redemption and early premium fees of $12 million, which resulted in a loss on extinguishment of debt during the nine months ended September 30, 2021 of $12 million. The Company funded the redemption with cash on hand and borrowings under its revolving credit facility.

Energen Notes

In connection with the E&P Merger, Diamondback E&P became the successor issuer under the indenture, dated as of September 1, 1996, pursuant to which Energen issued $100 million aggregate principal amount of 7.125% Medium-Term Notes, Series B due 2028 and $20 million aggregate principal amount of 7.32% Medium-Term Notes, Series A due 2022.

Viper's Credit Agreement

Viper LLC's existing credit agreement, as amended by the seventh amendment on June 2, 2021 (the "Viper Amendment"), provides for a revolving credit facility in the maximum credit amount of $2.0 billion with a borrowing base of $580 million based on Viper LLC's oil and natural gas reserves and other factors. Among other changes, the Viper Amendment added new provisions that allow Viper LLC to elect a commitment amount that is less than its borrowing base as determined by the lenders. As of September 30, 2021, the elected commitment amount was $500 million with $92 million of outstanding borrowings and $408 million available for future borrowings. The borrowing base is scheduled to be redetermined semi-annually in May and November, and is expected to be reaffirmed at $580 million by the lenders during the redetermination in November 2021. During the three and nine months ended September 30, 2021 and 2020, the weighted average interest rate on borrowings under the Viper credit agreement was 1.98%, 2.14%, 2.14% and 2.66%, respectively. The Viper credit agreement will mature on June 2, 2025. As of September 30, 2021, Viper LLC was in compliance with all financial maintenance covenants under the Viper credit agreement.

Rattler's Credit Agreement

Rattler LLC's credit agreement, as amended, provides for a revolving credit facility in the maximum credit amount of $600 million, which is expandable to $1.0 billion upon Rattler's election, subject to obtaining additional lender commitments and satisfaction of customary conditions. As of September 30, 2021, Rattler LLC had no outstanding borrowings and $600 million available for future borrowings under the Rattler credit agreement. During the three and nine months ended September 30, 2021 and 2020, the weighted average interest rate on borrowings under the Rattler credit agreement was 1.34%, 1.38%, 1.46% and 2.18%, respectively. The revolving credit facility will mature on May 28, 2024. As of September 30, 2021, Rattler LLC was in compliance with all financial maintenance covenants under the Rattler credit agreement.

8. CAPITAL STOCK AND EARNINGS PER SHARE

Diamondback did not complete any equity offerings during the nine months ended September 30, 2021 and September 30, 2020. As discussed in Note 4—Acquisitions and Divestitures, Diamondback issued 12.12 million shares of the Company's stock as consideration for the QEP Merger and 10.68 million shares of the Company's stock as consideration for the Guidon Acquisition during the nine months ended September 30, 2021.

Stock Repurchase Program

In September 2021, the Company's board of directors approved a stock repurchase program to acquire up to $2 billion of the Company's outstanding common stock. Purchases under the repurchase program may be made from time to time in open market or privately negotiated transactions, and are subject to market conditions, applicable legal requirements, contractual obligations and other factors. The repurchase program does not require the Company to acquire any specific number of shares. This repurchase program may be suspended from time to time, modified, extended or discontinued by the board of directors at any time. During the three and nine months ended September 30, 2021, the Company repurchased approximately $22 million of common stock under this repurchase program, respectively. As of September 30, 2021, $1.98 billion remained available for use to repurchase shares under the Company's common stock repurchase program.

Earnings (Loss) Per Share

The Company's basic earnings (loss) per share amounts have been computed based on the weighted-average number of shares of common stock outstanding for the period. Diluted earnings per share include the effect of potentially dilutive shares outstanding for the period. Additionally, the per share earnings of Viper and Rattler are included in the consolidated earnings per share computation based on the consolidated group's holdings of the subsidiaries.

A reconciliation of the components of basic and diluted earnings per common share is presented in the table below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
	($ in millions, except per share amounts, shares in thousands)			
Net income (loss) attributable to common stock	$ 649	$ (1,113)	$ 1,180	$ (3,778)
Weighted average common shares outstanding:				
Basic weighted average common shares outstanding	181,027	157,833	175,464	157,984
Effect of dilutive securities:				
Potential common shares issuable (1)	1,122	—	1,089	—
Diluted weighted average common shares outstanding	182,149	157,833	176,553	157,984
Basic net income (loss) attributable to common stock	$ 3.59	$ (7.05)	$ 6.73	$ (23.91)
Diluted net income (loss) attributable to common stock	$ 3.56	$ (7.05)	$ 6.68	$ (23.91)

(1) For the three and nine months ended September 30, 2021, there were 58,522 and 69,199 potential common units, respectively, excluded from the computation of diluted earnings per share because their inclusion would have been anti-dilutive under the treasury stock method. For the three and nine months ended September 30, 2020, no potential common units were included in the computation of diluted earnings per share because their inclusion would have been anti-dilutive.

Change in Ownership of Consolidated Subsidiaries

Non-controlling interests in the accompanying condensed consolidated financial statements represent minority interest ownership in Viper and Rattler and are presented as a component of equity. When the Company's relative ownership interests in Viper and Rattler change, adjustments to non-controlling interest and additional paid-in-capital, tax effected, will occur. The following table summarizes changes in the ownership interest in consolidated subsidiaries during the periods presented:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
	(In millions)			
Net income (loss) attributable to the Company	$ 649	$ (1,113)	$ 1,180	$ (3,778)
Change in ownership of consolidated subsidiaries	(6)	—	(13)	329
Change from net income (loss) attributable to the Company's stockholders and transfers to non-controlling interest	$ 643	$ (1,113)	$ 1,167	$ (3,449)

9. EQUITY-BASED COMPENSATION

On June 3, 2021, the Company's stockholders approved and adopted the Company's 2021 amended and restated equity incentive plan (the "Equity Plan"), which, among other things, increased total shares authorized for issuance from 8.3 million to 11.8 million. At September 30, 2021, the Company had 8.3 million shares of common stock available for future grants.

Under the Equity Plan, approved by the Board of Directors, the Company is authorized to issue incentive and non-statutory stock options, restricted stock awards and restricted stock units, performance awards and stock appreciation rights to eligible employees. At September 30, 2021, the Company had outstanding restricted stock units, performance-based restricted stock units, immaterial amounts of restricted share awards and restricted stock units which were assumed in connection with the QEP Merger and immaterial amounts of stock options and stock appreciation rights. The Company classifies these as equity-based awards and estimates the fair values of restricted stock awards and units as the closing price of the Company's common stock on the grant date of the award, which is expensed over the applicable vesting period. The Company values its stock options using a Black-Scholes option valuation model.

In addition to the Equity Plan, Viper and Rattler maintain their own long-term incentive plans which are not significant to the Company.

The following table presents the financial statement impacts of the equity compensation plans and related costs:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
	(In millions)			
General and administrative expenses	$ 14	$ 9	$ 37	$ 27
Equity-based compensation capitalized pursuant to full cost method of accounting for oil and natural gas properties	$ 5	$ 4	$ 14	$ 12

Restricted Stock Units

The following table presents the Company's restricted stock unit activity during the nine months ended September 30, 2021 under the Equity Plan and the QEP equity incentive plan assumed by the Company in the QEP Merger:

	Restricted Stock Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2020	1,113,480	$ 48.58
Granted(1)	655,634	$ 80.06
Vested	(323,459)	$ 77.21
Forfeited	(67,450)	$ 50.23
Unvested at September 30, 2021	1,378,205	$ 56.76

(1) Includes 164,088 replacement restricted stock unit awards granted in connection with the QEP Merger, the majority of which vested upon closing of the QEP Merger. For additional information regarding the QEP Merger, see Note 4—Acquisitions and Divestitures.

The aggregate fair value of restricted stock units that vested during the nine months ended September 30, 2021 was $25 million. As of September 30, 2021, the Company's unrecognized compensation cost related to unvested restricted stock units was $53 million, which is expected to be recognized over a weighted-average period of 2.0 years.

Performance Based Restricted Stock Units

The following table presents the Company's performance restricted stock units activity under the Equity Plan for the nine months ended September 30, 2021:

	Performance Restricted Stock Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2020	411,587	$ 99.10
Granted	198,454	$ 131.06
Unvested at September 30, 2021(1)	610,041	$ 109.49

(1) A maximum of 1,431,833 units could be awarded based upon the Company's final TSR ranking.

As of September 30, 2021, the Company's unrecognized compensation cost related to unvested performance based restricted stock awards and units was $32 million, which is expected to be recognized over a weighted-average period of 1.7 years.

In March 2021, eligible employees received performance restricted stock unit awards totaling 198,454 units from which a minimum of 0% and a maximum of 200% of the units could be awarded based upon the measurement of total stockholder return of the Company's common stock as compared to a designated peer group during the three-year performance period of January 1, 2021 to December 31, 2023 and cliff vest at December 31, 2023 subject to continued employment. The initial payout of the March 2021 awards will be further adjusted by a TSR modifier that may reduce the payout or increase the payout up to a maximum of 250%.

The fair value of each performance restricted stock unit issuance is estimated at the date of grant using a Monte Carlo simulation, which results in an expected percentage of units to be earned during the performance period.

The following table presents a summary of the grant-date fair values of performance restricted stock units granted and the related assumptions for the awards granted during the period presented:

	2021
Grant-date fair value	$ 131.06
Risk-free rate	0.15 %
Company volatility	69.60 %

10. INCOME TAXES

The Company's effective income tax rates were 22.3% and 21.6% for the three months ended September 30, 2021 and 2020, respectively, and 22.3% and 18.7% for the nine months ended September 30, 2021 and 2020, respectively. Total income tax expense from continuing operations for the three and nine months ended September 30, 2021 differed from amounts computed by applying the United States federal statutory tax rate to pre-tax income primarily due to (i) state income taxes, net of federal benefit, and (ii) the impact of permanent differences between book and taxable income, partially offset by (iii) tax benefit resulting from a reduction in the valuation allowance on Viper's deferred tax assets due to pre-tax income for the period.

For the nine months ended September 30, 2021, the Company's items of discrete income tax expense or benefit were not material.

On March 17, 2021, the Company completed its acquisition of QEP. For federal income tax purposes, the transaction qualified as a nontaxable merger whereby the Company acquired carryover tax basis in QEP's assets and liabilities. As of September 30, 2021, the Company's opening balance sheet net deferred tax asset was $17 million, primarily consisting of deferred tax assets related to tax attributes acquired from QEP, partially offset by a valuation allowance, and deferred tax liabilities resulting from the excess of financial reporting carrying value over tax basis of oil and natural gas properties and other assets acquired from QEP. The acquired income tax attributes, including federal net operating loss and credit carryforwards, are subject to an annual limitation under Internal Revenue Code Section 382. The Company has considered the positive and negative evidence regarding realizability of these federal tax attributes including taxable income in prior carryback years, the annual limitation imposed by Section 382, and the anticipated timing of reversal of its deferred tax liabilities, resulting in a valuation allowance on the portion of QEP's federal tax attributes estimated not more likely than not to be realized prior to expiration. In addition, acquired tax attributes include state net operating loss carryforwards for which a valuation allowance has been provided, since the Company does not believe the state net operating losses are more likely than not to be realized based on its assessment of anticipated future operations in those states.

Total income tax expense from continuing operations for the three and nine months ended September 30, 2020 differed from amounts computed by applying the United States federal statutory tax rate to pre-tax loss primarily due to (i) the impact of recording a valuation allowance on Viper's deferred tax assets, (ii) state income taxes and (iii) the impact of permanent differences between book and taxable income, partially offset by tax benefit resulting from the carryback of federal net operating losses.

For the nine months ended September 30, 2020, the Company recorded a discrete income tax expense of $143 million related to application in the first quarter of a valuation allowance on Viper's beginning-of-year deferred tax assets, which consisted primarily of its investment in Viper LLC and federal net operating loss carryforwards. As of September 30, 2021 and 2020, Viper maintained a valuation allowance against its deferred tax assets, based on its assessment of all available evidence, both positive and negative, supporting realizability of Viper's deferred tax assets. In addition, for the nine months ended

September 30, 2020, the Company recorded a discrete income tax benefit of $25 million related to the available carryback of certain federal net operating losses to tax year(s) in which the corporate income tax rate was 35%.

The Company considered the impact of the American Rescue Plan, enacted on March 11, 2021, and concluded its provisions related to U.S. income taxes for corporations did not materially affect the Company's current or deferred tax balances. The Company also considered the impact of the CARES Act, enacted March 27, 2020, in the period of enactment, resulting in a net discrete income tax benefit of $25 million for the three months ended March 31, 2020 related to the carryback of approximately $179 million of the Company's federal net operating losses as noted above. As a result of the refund associated with such carryback as well as the accelerated refund available for minimum tax credits, the Company received a refund of federal taxes in the first quarter of 2021 of approximately $100 million. In addition, the Company received in the third quarter of 2021 a refund of federal taxes of approximately $50 million related to refundable minimum tax credits resulting from carryback of certain federal net operating losses acquired from QEP.

11. DERIVATIVES

At September 30, 2021, the Company has commodity derivative contracts and receive-fixed, pay-variable interest rate hedges outstanding. All derivative financial instruments are recorded at fair value.

Commodity Contracts

The Company has entered into multiple crude oil, natural gas and natural gas liquids derivatives, indexed to the respective indices as noted in the table below, to reduce price volatility associated with certain of its oil and natural gas sales. The Company has not designated its commodity derivative instruments as hedges for accounting purposes and, as a result, marks its commodity derivative instruments to fair value and recognizes the cash and non-cash changes in fair value in the condensed consolidated statements of operations under the caption "Gain (loss) on derivative instruments, net."

By using derivative instruments to economically hedge exposure to changes in commodity prices, the Company exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes the Company, which creates credit risk. The Company's counterparties are participants in the secured second amended and restated credit agreement, which is secured by substantially all of the assets of the guarantor subsidiaries; therefore, the Company is not required to post any collateral. The Company does not require collateral from its counterparties. The Company has entered into commodity derivative instruments only with counterparties that are also lenders under its credit facility and have been deemed an acceptable credit risk.

The Company has multiple commodity derivative contracts that contain an other-than-insignificant financing element at inception and, therefore, the cash receipts were classified as cash flows from financing activities in the condensed consolidated statements of cash flow for the three and nine months ended September 30, 2021.

As of September 30, 2021, the Company had the following outstanding commodity derivative contracts. When aggregating multiple contracts, the weighted average contract price is disclosed.

					Swaps		Collars	
Settlement Month	Settlement Year	Type of Contract	Bbls/MMBtu Per Day	Index	Weighted Average Differential	Weighted Average Fixed Price	Weighted Average Floor Price	Weighted Average Ceiling Price
OIL								
Oct. - Dec.	2021	Swap	30,674	WTI	$—	$42.36	$—	$—
Oct. - Dec.	2021	Swap	5,000	Argus WTI Houston	$—	$37.78	$—	$—
Oct. - Dec.	2021	Swap(1)	5,000	Brent	$—	$41.62	$—	$—
Oct. - Dec.	2021	Basis Swap(2)	34,000	Argus WTI Midland	$0.91	$—	$—	$—
Oct. - Dec.	2021	Roll Swap(3)(4)	64,000	WTI	$0.56	$—	$—	$—
Oct. - Dec.	2021	Costless Collar	29,663	WTI	$—	$—	$39.83	$56.45
Oct. - Dec.	2021	Costless Collar	5,000	Argus WTI Houston	$—	$—	$45.00	$78.75
Oct. - Dec.	2021	Costless Collar(5)	54,000	Brent	$—	$—	$41.04	$52.86
Jan. - June	2022	Swap	1,000	WTI	$—	$45.00	$—	$—
Jan. - Dec.	2022	Basis Swap(2)	10,000	Argus WTI Midland	$0.84	$—	$—	$—
Jan. - Dec.	2022	Roll Swap(3)	25,000	WTI	$0.56	$—	$—	$—
Jan. - Mar.	2022	Costless Collar	19,500	WTI	$—	$—	$46.28	$72.67
Jan. - Mar.	2022	Costless Collar	55,000	Brent	$—	$—	$45.55	$71.08
Jan. - Mar.	2022	Costless Collar	22,000	Argus WTI Houston	$—	$—	$45.91	$70.95
Apr. - June	2022	Costless Collar	13,000	WTI	$—	$—	$46.92	$75.00
Apr. - June	2022	Costless Collar	34,000	Brent	$—	$—	$46.47	$77.00
Apr. - June	2022	Costless Collar	26,000	Argus WTI Houston	$—	$—	$46.92	$72.78
July - Sep.	2022	Costless Collar	11,000	Brent	$—	$—	$47.73	$78.65
July - Sep.	2022	Costless Collar	10,000	Argus WTI Houston	$—	$—	$50.00	$76.66
Oct. - Dec.	2022	Costless Collar	5,000	Brent	$—	$—	$45.00	$75.56
NATURAL GAS								
Oct. - Dec.	2021	Swap	245,000	Henry Hub	$—	$2.65	$—	$—
Oct. - Dec.	2021	Swap	50,000	Waha Hub	$—	$1.92	$—	$—
Oct. - Dec.	2021	Basis Swap(2)	250,000	Waha Hub	$(0.66)	$—	$—	$—
Jan. - Dec.	2022	Basis Swap(2)	210,000	Waha Hub	$(0.34)	$—	$—	$—
Jan. - June	2022	Costless Collar	350,000	Henry Hub	$—	$—	$2.65	$4.68
July - Dec.	2022	Costless Collar	240,000	Henry Hub	$—	$—	$2.67	$5.00
Jan. - Dec.	2023	Costless Collar	60,000	Henry Hub	$—	$—	$2.75	$5.72
NATURAL GAS LIQUIDS								
Oct. - Dec.	2021	Swap	2,000	Mont Belvieu Propane	$—	$29.40	$—	$—

(1) Excludes swaptions for 13,900 BO/d for first half of 2022, and 8,250 BO/d for second half 2022, whereby the counterparty has the right to exercise the hedge at a weighted-average price of $67.54/Bbl in the first half of 2022 and $68.62/Bbl in the second half of 2022.

(2) The Company has fixed price basis swaps for the spread between the Cushing crude oil price and the Midland WTI crude oil price as well as the spread between the Henry Hub natural gas price and the Waha Hub natural gas price. The weighted average differential represents the amount of reduction to the Cushing, Oklahoma oil price and the Waha Hub natural gas price for the notional volumes covered by the basis swap contracts.

(3) The Company has rolling hedge basis swaps for the differential in NYMEX prices between the calendar month average and the physical crude oil delivery month. The weighted average differential represents the amount of reduction to Cushing, Oklahoma oil price for the notional volumes covered by the rolling hedge basis swap contracts.
(4) Includes a rolling hedge basis swap contract for the differential between the NYMEX prices for WTI Cushing and WTI CMA calendar month average of each basis for a notional quantity of 4,000 barrels per day with a weighted average differential of $0.00.
(5) Excludes approximately $4.8 million of deferred premiums from restructuring 5,000 BO/d of Q4 2021 hedges.

Settlement Month	Settlement Year	Type of Contract	Bbls Per Day	Index	Strike Price	Deferred Premium
OIL						
Jan. - Mar.	2022	Put	9,500	WTI	$47.51	$1.57
Jan. - Mar.	2022	Put	8,000	Brent	$50.00	$1.70
Jan. - Sep.	2022	Put	2,000	Argus WTI Houston	$50.00	$2.06
Apr. - June	2022	Put	8,000	WTI	$47.50	$1.55
Apr. - June	2022	Put	10,000	Brent	$50.00	$1.76
July - Sep.	2022	Put	6,000	Brent	$50.00	$1.87
Oct. - Dec.	2022	Put	2,000	Brent	$50.00	$1.89

Interest Rate Swaps

In the second quarter of 2021, the Company entered into two interest rate swap agreements for notional amounts of $600 million each to limit the Company’s exposure to changes in the fair value of debt due to movements in LIBOR interest rates. These interest rate swaps have been designated as fair value hedges of the Company’s $1.2 billion 3.50% fixed rate senior notes due 2029 (the “2029 Notes”) whereby the Company will receive the fixed rate of interest and will pay an average variable rate of interest based on three month LIBOR plus 2.1865%. Gains and losses due to changes in the fair value of the interest rate swaps completely offset changes in the fair value of the hedged portion of the underlying debt, and were not material for the three and nine months ended September 30, 2021. These interest rate swaps are assumed to be perfectly effective and were determined to qualify for the “shortcut” method of accounting. The swaps expire on December 1, 2029, with an alternative early termination date of September 1, 2029, which mirrors the call option in the 2029 Notes.

During 2020 and the first quarter of 2021, the Company used interest rate swaps to reduce its exposure to variable rate interest payments associated with the Company’s revolving credit facility. These interest rate swaps were not designated as hedging instruments and as a result, the Company recognized all changes in fair value immediately in earnings. During the first quarter of 2021, the Company terminated all of its previously outstanding interest rate swaps which resulted in cash received upon settlement of $80 million, net of fees, during the nine months ended September 30, 2021. The interest swaps contained an other-than-insignificant financing element at inception, and therefore, the cash receipts were classified as cash flows from financing activities in the condensed consolidated statements of cash flow for the nine months ended September 30, 2021.

Balance Sheet Offsetting of Derivative Assets and Liabilities

The fair value of derivative instruments is generally determined using established index prices and other sources which are based upon, among other things, futures prices and time to maturity. These fair values are recorded by netting asset and liability positions, including any deferred premiums that are with the same counterparty and are subject to contractual terms which provide for net settlement. See Note 12—Fair Value Measurements for further details.

Gains and Losses on Derivative Instruments

The following table summarizes the gains and losses on derivative instruments not designated as hedging instruments included in the condensed consolidated statements of operations:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
	(In millions)			
Gain (loss) on derivative instruments, net:				
Commodity contracts	$ (234)	$ (104)	$ (1,025)	$ 147
Interest rate swaps	—	5	130	(65)
Total	$ (234)	$ (99)	$ (895)	$ 82
Net cash received (paid) on settlements:				
Commodity contracts(1)(2)	$ (397)	$ (9)	$ (902)	$ 288
Interest rate swaps(3)	—	—	80	—
Total	$ (397)	$ (9)	$ (822)	$ 288

(1) The three and nine months ended September 30, 2021 include cash paid on commodity contracts terminated prior to their contractual maturity of $16 million.
(2) The three and nine months ended September 30, 2020 include cash received on commodity contracts terminated prior to their contractual maturity of $6 million and $17 million, respectively.
(3) The nine months ended September 30, 2021 include cash received on interest rate swap contracts terminated prior to their contractual maturity of $80 million.

12. FAIR VALUE MEASUREMENTS

Fair value is defined as 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. Valuation techniques used to measure fair value must maximize the use of observable inputs and minimize the use of unobservable inputs.

The fair value hierarchy is based on three levels of inputs, of which the first two are considered observable and the last unobservable, that may be used to measure fair value. The Company’s assessment of the significance of a particular input to the fair value measurements requires judgment and may affect the valuation of the assets and liabilities being measured and their placement within the fair value hierarchy. The Company uses appropriate valuation techniques based on available inputs to measure the fair values of its assets and liabilities.

Level 1 - Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date.

Level 2 - Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date.

Level 3 - Unobservable inputs that are not corroborated by market data and may be used with internally developed methodologies that result in management’s best estimate of fair value.

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

The Company estimates the fair values of proved oil and natural gas properties assumed in business combinations using discounted cash flow techniques and based on market assumptions as to the future commodity prices, internal estimates of future quantities of oil and natural gas reserves, future estimated rates of production, expected recovery rates and risk-adjustment discounts. The estimated fair values of unevaluated oil and natural gas properties were based on the location, engineering and geological studies, historical well performance, and applicable mineral lease terms. Given the unobservable nature of the inputs, the estimated fair values of oil and natural gas properties assumed is deemed to use Level 3 inputs.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Certain assets and liabilities are reported at fair value on a recurring basis, including the Company’s commodity derivative instruments and interest rate swaps. The fair values of the Company’s commodity derivative contracts are measured internally using established commodity futures price strips for the underlying commodity provided by a reputable third party, the contracted notional volumes, and time to maturity. Interest rate swaps designated as fair value hedges and those that are not designated as hedges are determined based on inputs that are readily available in public markets, can be derived from information available in publicly quoted markets, or are provided by financial institutions that trade these contracts. These valuations are Level 2 inputs. The net fair value of the Company’s interest rate swaps designated as hedges are included in long-term debt in the consolidated balance sheet.

The following table provides (i) fair value measurement information for financial assets and liabilities measured at fair value on a recurring basis, (ii) the gross amounts of recognized derivative assets and liabilities, (iii) the amounts offset under master netting arrangements with counterparties, and (iv) the resulting net amounts presented in the Company’s condensed consolidated balance sheets as of September 30, 2021 and December 31, 2020. The net amounts of derivative instruments are classified as current or noncurrent based on their anticipated settlement dates.

	As of September 30, 2021					
	Level 1	Level 2	Level 3	Total Gross Fair Value	Gross Amounts Offset in Balance Sheet	Net Fair Value Presented in Balance Sheet
				(In millions)		
Assets:						
Current:						
Derivative instruments	$ —	$ 94	$ —	$ 94	$ (94)	$ —
Interest rate swaps designated as hedges	$ —	$ 14	$ —	$ 14	$ —	$ 14
Non-current:						
Derivative instruments	$ —	$ 16	$ —	$ 16	$ (12)	$ 4
Interest rate swaps designated as hedges	$ —	$ 13	$ —	$ 13	$ (13)	$ —
Liabilities:						
Current:						
Derivative instruments	$ —	$ 704	$ —	$ 704	$ (94)	$ 610
Non-current:						
Derivative instruments	$ —	$ 24	$ —	$ 24	$ (12)	$ 12
Interest rate swaps designated as hedges	$ —	$ 37	$ —	$ 37	$ (13)	$ 24

	As of December 31, 2020					
	Level 1	Level 2	Level 3	Total Gross Fair Value	Gross Amounts Offset in Balance Sheet	Net Fair Value Presented in Balance Sheet
	(In millions)					
Assets:						
Current:						
Derivative instruments	$ —	$ 43	$ —	$ 43	$ (42)	$ 1
Non-current:						
Derivative instruments	$ —	$ 187	$ —	$ 187	$ (187)	$ —
Liabilities:						
Current:						
Derivative instruments	$ —	$ 291	$ —	$ 291	$ (42)	$ 249
Non-current:						
Derivative instruments	$ —	$ 244	$ —	$ 244	$ (187)	$ 57

Assets and Liabilities Not Recorded at Fair Value

The following table provides the fair value of financial instruments that are not recorded at fair value in the condensed consolidated balance sheets:

	September 30, 2021		December 31, 2020	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
Debt	$ 6,945	$ 7,448	$ 5,815	$ 6,213

The fair values of the Company's credit agreement, the Viper credit agreement and the Rattler credit agreement approximate their carrying values based on borrowing rates available to the Company for bank loans with similar terms and maturities and is classified as Level 2 in the fair value hierarchy. The fair values of the outstanding notes were determined using the September 30, 2021 quoted market price, a Level 1 classification in the fair value hierarchy.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are measured at fair value on a nonrecurring basis in certain circumstances. These assets and liabilities can include those acquired in a business combination, inventory, proved and unproved oil and gas properties and other long-lived assets that are written down to fair value when they are impaired or held for sale. Refer to Note 4—Acquisitions and Divestitures and Note 5—Property and Equipment for additional discussion of nonrecurring fair value adjustments.

Fair Value of Financial Assets

The carrying amount of cash and cash equivalents, receivables, funds held in escrow, prepaid expenses and other current assets, payables and other accrued liabilities approximate their fair value because of the short-term nature of the instruments.

13. COMMITMENTS AND CONTINGENCIES

The Company is a party to various routine legal proceedings, disputes and claims arising in the ordinary course of its business, including those that arise from interpretation of federal and state laws and regulations affecting the crude oil and natural gas industry, personal injury claims, title disputes, royalty disputes, contract claims, contamination claims relating to oil and natural gas exploration and development and environmental claims, including claims involving assets previously sold to third parties and no longer part of the Company's current operations. While the ultimate outcome of the pending proceedings, disputes or claims, and any resulting impact on the Company, cannot be predicted with certainty, the Company's management believes that none of these matters, if ultimately decided adversely, will have a material adverse effect on the Company's financial condition, results of operations or cash flows. The Company's assessment is based on information known about the pending matters and its experience in contesting, litigating and settling similar matters. Actual outcomes could differ materially from the Company's assessment. The Company records reserves for contingencies related to outstanding legal proceedings, disputes or claims when information available indicates that a loss is probable and the amount of the loss can be reasonably estimated.

The Company acquired certain contractual obligations in conjunction with the QEP Merger including an aggregate of approximately $68 million in various transportation, gathering and purchase commitments.

14. SUBSEQUENT EVENTS

Third Quarter 2021 Dividend Declaration

On October 28, 2021, the Board of Directors of the Company declared a cash dividend for the third quarter of 2021 of $0.50 per share of common stock, payable on November 18, 2021 to its stockholders of record at the close of business on November 11, 2021.

Drop Down Transaction

On October 19, 2021, Diamondback entered into a purchase and sale agreement with Rattler to sell certain water midstream assets to Rattler in exchange for cash proceeds of approximately $160 million, in a drop down transaction. The midstream assets consist primarily of produced water gathering and disposal systems, produced water recycling facilities, and sourced water gathering and storage assets acquired by the Company through the Guidon Acquisition and the QEP Merger with a carrying value of approximately $160 million. The drop down transaction will be accounted for as a transaction between entities under common control and is expected to close in the fourth quarter of 2021, subject to customary closing conditions.

Williston Basin Divestiture

On October 21, 2021, the Company completed the divestiture of its Williston Basin oil and natural gas assets, consisting of approximately 95,000 net acres, to Oasis Petroleum Inc., for net cash proceeds of approximately $586 million, after customary closing adjustments. This transaction did not result in a significant alteration of the relationship between the Company's capitalized costs and proved reserves and, accordingly, the Company recorded the proceeds as a reduction of its full cost pool with no gain or loss recognized on the sale.

Gas Gathering Assets Divestiture

On November 1, 2021, the Company completed the sale of certain gas gathering assets to Brazos Delaware Gas, LLC for proceeds of approximately $54 million, after customary closing adjustments.

Redemption of the 2023 Notes

On November 1, 2021, the Company redeemed all of its outstanding 2023 Notes in the aggregate principal amount of $650 million at a redemption price equal to 100% of the principal amount, plus accrued and unpaid interest on the 2023 Notes up to, but not including, the redemption date. The Company funded the redemption with proceeds received from the divestiture of its Williston Basin assets and cash on hand.

Viper's Swallowtail Acquisition

On October 1, 2021, Viper acquired certain mineral and royalty interests from Swallowtail Royalties LLC and Swallowtail Royalties II LLC (the "Swallowtail entities") pursuant to a definitive purchase and sale agreement for 15.25 million of Viper's common units and approximately $225 million in cash (the "Swallowtail Acquisition"). The mineral and royalty interests acquired in the Swallowtail Acquisition represent approximately 2,313 net royalty acres primarily in the Northern Midland Basin, of which approximately 62% are operated by Diamondback. The Swallowtail Acquisition has an effective date of August 1, 2021. In accordance with the terms of the purchase agreement, the Company deposited $30 million into an escrow account in August 2021, which was released to Swallowtail upon the closing of the transaction. The cash portion of this transaction was funded through a combination of cash on hand and approximately $190 million of borrowings under Viper LLC's revolving credit facility.

Rattler's Remuda Joint Venture Acquisition

On October 5, 2021, Rattler and a private affiliate of an investment fund formed a joint venture entity, Remuda Midstream Holdings LLC (the "Remuda joint venture"). Rattler contributed approximately $104 million in cash for a 25% membership interest in the Remuda joint venture, which then completed the acquisition of a majority interest in WTG Midstream LLC ("WTG Midstream") from West Texas Gas, Inc. and its affiliates. WTG Midstream's assets primarily consist of an interconnected gas gathering system and six major gas processing plants servicing the Midland Basin with 925 MMcf/d of total processing capacity with additional gas gathering and processing expansions planned.

Rattler's Gas Gathering Divestiture

On November 1, 2021, Rattler completed the sale of its gas gathering assets to Brazos Delaware Gas, LLC for aggregate total gross potential consideration of $93 million, consisting of (i) $83 million due at closing, after customary closing adjustments, (ii) a $5 million contingent payment due in 2023 if the aggregate actual deliveries of gas volumes into the gas gathering system by and/or on behalf of the Company and its affiliates exceed certain specified thresholds during 2022, and (iii) a $5 million contingent payment due in 2024 if the aggregate actual deliveries of gas volumes into the gas gathering system by and/or on behalf of the Company and its affiliates exceed certain specified thresholds during 2022 and 2023. The contingent payments will be recorded if and when they become realizable.

15. SEGMENT INFORMATION

The Company reports its operations in two operating segments: (i) the upstream segment, which is engaged in the acquisition, development, exploration and exploitation of unconventional, onshore oil and natural gas reserves primarily in the Permian Basin in West Texas and (ii) the midstream operations segment, which is focused on owning, operating, developing and acquiring midstream infrastructure assets in the Midland and Delaware Basins of the Permian Basin. All of the Company's equity method investments are included in the midstream operations segment.

The following tables summarize the results of the Company's operating segments during the periods presented:

	Upstream	Midstream Operations	Eliminations	Total
Three Months Ended September 30, 2021:		**(In millions)**		
Third-party revenues	$ 1,896	$ 14	$ —	$ 1,910
Intersegment revenues	—	95	(95)	—
Total revenues	1,896	109	(95)	1,910
Depreciation, depletion, amortization and accretion	324	17	—	341
Income (loss) from operations	1,126	54	(16)	1,164
Interest expense, net	(50)	(7)	—	(57)
Other income (expense)	(243)	4	(1)	(240)
Provision for (benefit from) income taxes	190	3	—	193
Net income (loss) attributable to non-controlling interest	16	9	—	25
Net income (loss) attributable to Diamondback Energy, Inc.	627	39	(17)	649
As of September 30, 2021:				
Total assets	$ 21,192	$ 1,806	$ (359)	$ 22,639

	Upstream	Midstream Operations	Eliminations	Total
Three Months Ended September 30, 2020:		(In millions)		
Third-party revenues	$ 706	$ 14	$ —	$ 720
Intersegment revenues	—	83	(83)	—
Total revenues	706	97	(83)	720
Depreciation, depletion, amortization and accretion	277	11	—	288
Impairment of oil and natural gas properties	1,451	—	—	1,451
Income (loss) from operations	(1,282)	44	(18)	(1,256)
Interest expense, net	(47)	(6)	—	(53)
Other income (expense)	(103)	4	(1)	(100)
Provision for (benefit from) income taxes	(307)	3	—	(304)
Net income (loss) attributable to non-controlling interest	(1)	9	—	8
Net income (loss) attributable to Diamondback Energy, Inc.	(1,124)	30	(19)	(1,113)
As of December 31, 2020:				
Total assets	$ 16,128	$ 1,809	$ (318)	$ 17,619

	Upstream	Midstream Operations	Eliminations	Total
Nine Months Ended September 30, 2021:		(In millions)		
Third-party revenues	$ 4,737	$ 38	$ —	$ 4,775
Intersegment revenues	—	281	(281)	—
Total revenues	4,737	319	(281)	4,775
Depreciation, depletion, amortization and accretion	911	44	—	955
Impairment of midstream assets	—	3	—	3
Income (loss) from operations	2,605	131	(46)	2,690
Interest expense, net	(147)	(23)	—	(170)
Other income (expense)	(967)	29	(5)	(943)
Provision for (benefit from) income taxes	344	8	—	352
Net income (loss) attributable to non-controlling interest	18	27	—	45
Net income (loss) attributable to Diamondback Energy, Inc.	1,129	102	(51)	1,180
As of September 30, 2021:				
Total assets	$ 21,192	$ 1,806	$ (359)	$ 22,639

	Upstream	Midstream Operations	Eliminations	Total
Nine Months Ended September 30, 2020:		(In millions)		
Third-party revenues	$ 2,002	$ 42	$ —	$ 2,044
Intersegment revenues	—	273	(273)	—
Total revenues	2,002	315	(273)	2,044
Depreciation, depletion, amortization and accretion	1,005	36	—	1,041
Impairment of oil and natural gas properties	4,999	—	—	4,999
Income (loss) from operations	(4,787)	134	(77)	(4,730)
Interest expense, net	(137)	(10)	—	(147)
Other income (expense)	73	(10)	(4)	59
Provision for (benefit from) income taxes	(910)	8	—	(902)
Net income (loss) attributable to non-controlling interest	(163)	25	—	(138)
Net income (loss) attributable to Diamondback Energy, Inc.	(3,778)	81	(81)	(3,778)
As of December 31, 2020:				
Total assets	$ 16,128	$ 1,809	$ (318)	$ 17,619

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with our unaudited consolidated financial statements and notes thereto presented in this report as well as our audited consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2020. The following discussion contains "forward-looking statements" that reflect our future plans, estimates, beliefs, and expected performance. Actual results and the timing of events may differ materially from those contained in these forward-looking statements due to a number of factors. See "Part II. Item 1A. Risk Factors" and "Cautionary Statement Regarding Forward-Looking Statements."

Overview

We operate in two operating segments: (i) the upstream segment, which is engaged in the acquisition, development, exploration and exploitation of unconventional, onshore oil and natural gas reserves primarily in the Permian Basin in West Texas and (ii) through our subsidiary, Rattler, the midstream operations segment, which is focused on ownership, operation, development and acquisition of midstream infrastructure assets in the Midland and Delaware Basins of the Permian Basin.

Guidon Acquisition and QEP Merger

On February 26, 2021, we completed the Guidon Acquisition, which included approximately 32,500 net acres in the Northern Midland Basin, in exchange for 10.68 million shares of the Company's common stock and $375 million of cash.

On March 17, 2021, we completed the acquisition of QEP pursuant to the Agreement and Plan of Merger, dated as of December 20, 2020, by and among Diamondback, certain of our subsidiaries and QEP. The addition of QEP's assets increased our net acreage in the Midland Basin by approximately 49,000 net acres. Under the terms of the merger agreement, we issued approximately 12.12 million shares of our common stock (valued at a price of $81.41 per share on the closing date) to the former QEP stockholders, with a total value of approximately $987 million.

See Note 4—Acquisitions and Divestitures for additional discussion of the Guidon Acquisition and the QEP Merger.

Recent Developments

Recent and Pending Acquisitions and Divestitures

On October 19, 2021, we entered into a purchase and sale agreement with Rattler to sell certain water midstream assets with a carrying value of approximately $160 million to Rattler in exchange for cash proceeds of approximately $160 million. The drop down transaction is expected to close in the fourth quarter of 2021, subject to customary closing conditions.

On October 21, 2021 we completed the divestiture of our Williston Basin oil and natural gas assets, consisting of approximately 95,000 net acres acquired in the QEP Merger, for net cash proceeds of approximately $586 million after customary closing adjustments.

On November 1, 2021, we completed the sale of certain gas gathering assets to Brazos Delaware Gas, LLC for proceeds of approximately $54 million, after customary closing adjustments.

On October 1, 2021, Viper completed the Swallowtail Acquisition, which included certain mineral and royalty interests for 15.25 million of Viper's common units and approximately $225 million in cash. The cash portion of the purchase price was funded through a combination of cash on hand and approximately $190 million of borrowings under Viper LLC's revolving credit facility.

On October 5, 2021, Rattler contributed approximately $104 million in cash for a 25% membership interest in the Remuda joint venture, which then completed the acquisition of a majority interest in WTG Midstream.

On November 1, 2021, Rattler completed the sale of its gas gathering assets to Brazos Delaware Gas, LLC for proceeds of approximately $83 million at closing, subject to customary closing adjustments, and an aggregate of $10 million in contingent payments.

Redemption of Notes

In August 2021, we redeemed the remaining $432 million in aggregate principal amount of our outstanding 5.375% 2025 Senior Notes with cash on hand and borrowings under our revolving credit facility.

On November 1, 2021, we redeemed the aggregate $650 million principal amount of our outstanding 2023 Senior Notes with the proceeds received from the divestiture of our Williston Basin assets and cash on hand.

See Note 14—Subsequent Events for additional discussion of transactions completed in the fourth quarter of 2021.

Stock Repurchase Program

In September 2021, our board of directors approved a stock repurchase program to acquire up to $2 billion of our outstanding common stock. This repurchase program is another component of our capital return program, which also includes our quarterly dividend. We anticipate the repurchase program will be funded primarily by free cash flow generated from operations and liquidity events such as the sale of assets. Purchases under the repurchase program may be made from time to time in open market or privately negotiated transactions, and are subject to market conditions, applicable legal requirements, contractual obligations and other factors. The repurchase program does not require us to acquire any specific number of shares and may be suspended from time to time, modified, extended or discontinued by the board of directors at any time. During the three and nine months ended September 30, 2021, we repurchased approximately $22 million shares of our common stock, and as of September 30, 2021, $1.98 billion remained available for future purchases under our common stock repurchase program.

COVID-19 and Commodity Prices

In early March 2020, oil prices dropped sharply and continued to decline, briefly reaching negative levels as a result of multiple factors affecting the supply and demand in global oil and natural gas markets, including (i) actions taken by OPEC members and other exporting nations impacting commodity price and production levels and (ii) a significant decrease in demand due to the ongoing COVID-19 pandemic. Additionally, the Delta variant emerged in March 2021 and became highly transmissible in July 2021, which contributed to additional pricing and demand volatility during the third quarter of 2021. However, certain restrictions on conducting business that were implemented in response to the COVID-19 pandemic have been lifted as improved treatments and vaccinations for COVID-19 have been rolled-out globally since late 2020. As a result, oil and natural gas market prices have improved in 2021 in response to the overall increase in demand.

During 2020 and 2021, the posted NYMEX WTI price for crude oil ranged from $(37.63) to $80.64 per Bbl, and the NYMEX Henry Hub price of natural gas ranged from $1.48 to $6.31 per MMBtu. On October 13, 2021, the NYMEX WTI price for crude oil was $80.44 per Bbl and the NYMEX Henry Hub price of natural gas was $5.59 per MMBtu. Commodity prices have historically been volatile and we cannot predict events which may lead to future fluctuations in these prices.

In addition to the volatility in commodity prices and the impact of the COVID-19 pandemic on our business and industry, our results of operations may be adversely impacted by any government rule, regulation or order that may impose production limits, as well as pipeline capacity and storage constraints, in the Permian Basin where we operate.

As a result of the reduction in crude oil demand caused by factors discussed above, in 2020, we lowered our 2020 capital budgets and production guidance. We have since restored curtailed production in the second half of 2020 to stem production declines and respond to improved demand and increasing commodity prices, but have elected to keep production relatively flat during the remainder of 2021, focusing on cost control and using excess cash flow for debt payment and return of capital to our stockholders.

During the third quarter of 2021, we continued building on our execution track record, generating free cash flow while keeping capital costs under control, and our efficiency gains, particularly in the Midland Basin drilling and completion programs, were able to mitigate certain inflationary pressures on well costs and have led to our second decrease in capital guidance in 2021, now down 10% from our guidance presented in April of 2021. We expect to continue to exercise capital discipline and maintain flat oil production in 2022 and believe that this can be accomplished by spending similar capital to our fourth quarter 2021 guidance. This capital range accounts for the inflationary pressures seen this year and anticipated in 2022. We expect to be in a position to continue to deliver on the recently announced enhanced capital return program, where we expect to distribute 50% of our quarterly free cash flow to our stockholders, beginning with the fourth quarter 2021. Our capital return program is currently focused on our sustainable and growing dividend and a combination of stock repurchases and variable dividends, which are expected to be used interchangeably, depending on which option we believe presents the best return of capital to our stockholders at the relevant time.

Third Quarter 2021 Operating Highlights

- We recorded net income of $649 million for the third quarter of 2021.
- Our average production was 404.3 MBOE/d during the third quarter of 2021.
- During the third quarter of 2021, we drilled 47 gross horizontal wells in the Midland Basin and 11 gross horizontal wells in the Delaware Basin.
- We turned 73 gross operated horizontal wells (63 in the Midland Basin and 10 in the Delaware Basin) to production and had capital expenditures, excluding acquisitions, of $391 million during the third quarter of 2021.
- The average lateral length for the wells completed during the third quarter of 2021 was 11,225 feet.
- Our cash operating costs for the third quarter of 2021 were $9.97 per BOE, including lease operating expenses of $4.19 per BOE, cash general and administrative expenses of $0.65 per BOE and production and ad valorem taxes and gathering and transportation expenses of $5.13 per BOE.
- On October 28, 2021, our board of directors declared a cash dividend for the third quarter of 2021 of $0.50 per share of common stock, payable on November 18, 2021 to our stockholders of record at the close of business on November 11, 2021.

Upstream Segment

In our upstream segment, our activities are primarily directed at the horizontal development of the Wolfcamp and Spraberry formations in the Midland Basin and the Wolfcamp and Bone Spring formations in the Delaware Basin within the Permian Basin. We intend to continue to develop our reserves and increase production through development drilling and exploitation and exploration activities on our multi-year inventory of identified potential drilling locations and through acquisitions that meet our strategic and financial objectives, targeting oil-weighted reserves. Additionally, our publicly-traded subsidiary, Viper, is focused on owning and acquiring mineral interests and royalty interests in oil and natural gas properties primarily in the Permian Basin and derives royalty income and lease bonus income from such interests.

As of September 30, 2021, we had approximately 540,915 net acres, which primarily consisted of approximately 263,208 net acres in the Midland Basin and 149,405 net acres in the Delaware Basin. Additionally, completed the divestiture of all of our Williston Basin assets totaling approximately 95,000 net acres in October 2021.

The following table sets forth the total number of operated horizontal wells drilled and completed during the three and nine months ended September 30, 2021:

	Three Months Ended September 30, 2021				Nine Months Ended September 30, 2021			
	Drilled		Completed(1)		Drilled		Completed(2)	
Area	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Midland Basin	47	44	63	59	135	127	152	140
Delaware Basin	11	10	10	9	28	26	49	46
Other	—	—	—	—	—	—	4	3
Total	58	54	73	68	163	153	205	189

(1) The average lateral length for the wells completed during the third quarter of 2021 was 11,225 feet. Operated completions during the third quarter of 2021 consisted of 23 Wolfcamp A wells, 21 Lower Spraberry wells, 10 Middle Spraberry wells, eight Jo Mill wells, four Wolfcamp B wells, four Dean wells, two Second Bone Springs wells and one Third Bone Springs wells.

(2) The average lateral length for the wells completed during the first nine months of 2021 was 10,906 feet. Operated completions during the first nine months of 2021 consisted of 61 Wolfcamp A wells, 50 Lower Spraberry wells, 25 Middle Spraberry wells, 21 Jo Mill wells, 17 Wolfcamp B wells, 10 Second Bone Springs wells, nine Third Bone Springs wells, seven Dean wells, two Bakken wells, two Three Forks wells and one Barnett well.

As of September 30, 2021, we operated the following wells:

	As of September 30, 2021					
	Vertical Wells		Horizontal Wells		Total	
Area	Gross	Net	Gross	Net	Gross	Net
Midland Basin	2,298	2,142	1,689	1,565	3,987	3,707
Delaware Basin	28	25	656	613	684	638
Other	—	—	412	356	412	356
Total	2,326	2,167	2,757	2,534	5,083	4,701

As of September 30, 2021, we held interests in 11,214 gross (4,844 net) wells, including wells that we do not operate. During the first quarter of 2021, we acquired interests in 1,671 gross (1,240 net) wells as part of the QEP Merger.

Midstream Operations

In our midstream operations segment, Rattler's crude oil infrastructure assets consist of gathering pipelines and metering facilities, which collectively gather crude oil for its customers. Rattler's facilities gather crude oil from horizontal and vertical wells in our ReWard, Spanish Trail, Pecos and Glasscock areas within the Permian Basin. Rattler's water sourcing and distribution assets consist of water wells, hydraulic fracturing pits, pipelines and water treatment facilities, which collectively gather and distribute water from Permian Basin aquifers to the drilling and completion sites through buried pipelines and temporary surface pipelines. Rattler's gathering and disposal system spans approximately 521 miles and consists of gathering pipelines along with produced water disposal wells and facilities which collectively gather and dispose of produced water from operations throughout our Permian Basin acreage.

We have entered into multiple fee-based commercial agreements with Rattler, each with an initial term ending in 2034, utilizing Rattler's infrastructure assets or its planned infrastructure assets to provide an array of essential services critical to our upstream operations in the Delaware and Midland Basins. Our agreements with Rattler include substantial acreage dedications.

The midstream operations segment's revenues and operating expenses were not significant to our condensed consolidated statements of operations for the three and nine months ended September 30, 2021 and 2020. See Note 15—Segment Information for further details regarding acquisitions.

Results of Operations

The following table sets forth selected operating data for the three and nine months ended September 30, 2021 and 2020:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Revenues (In millions):				
Oil sales	$ 1,506	$ 606	$ 3,845	$ 1,785
Natural gas sales	152	36	363	61
Natural gas liquid sales	239	65	528	156
Total oil, natural gas and natural gas liquid revenues	$ 1,897	$ 707	$ 4,736	$ 2,002
Production Data:				
Oil (MBbls)	22,058	15,639	60,703	50,009
Natural gas (MMcf)	45,571	32,505	124,186	96,482
Natural gas liquids (MBbls)	7,540	5,377	19,992	16,326
Combined volumes (MBOE)(1)	37,193	26,433	101,393	82,415
Daily oil volumes (BO/d)	239,761	169,989	222,355	182,515
Daily combined volumes (BOE/d)	404,272	287,315	371,403	300,785
Average Prices:				
Oil ($ per Bbl)	$ 68.27	$ 38.75	$ 63.34	$ 35.69
Natural gas ($ per Mcf)	$ 3.34	$ 1.11	$ 2.92	$ 0.63
Natural gas liquids ($ per Bbl)	$ 31.70	$ 12.09	$ 26.41	$ 9.56
Combined ($ per BOE)	$ 51.00	$ 26.75	$ 46.71	$ 24.29
Oil, hedged ($ per Bbl)(2)	$ 53.81	$ 38.17	$ 50.46	$ 41.31
Natural gas, hedged ($ per MMBtu)(2)	$ 2.04	$ 0.95	$ 2.13	$ 0.57
Natural gas liquids, hedged ($ per Bbl)(2)	$ 31.30	$ 12.09	$ 26.16	$ 9.56
Average price, hedged ($ per BOE)(2)	$ 40.76	$ 26.22	$ 37.97	$ 27.63

(1) Bbl equivalents are calculated using a conversion rate of six Mcf per one Bbl.

(2) Hedged prices reflect the effect of our commodity derivative transactions on our average sales prices and include gains and losses on cash settlements for matured commodity derivatives, which we do not designate for hedge accounting. Hedged prices exclude gains or losses resulting from the early settlement of commodity derivative contracts.

Production Data

Substantially all of our revenues are generated through the sale of oil, natural gas and natural gas liquids production. The following tables set forth the mix of our production data by product and basin for the three and nine months ended September 30, 2021 and 2020:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Oil (MBbls)	59 %	59 %	60 %	61 %
Natural gas (MMcf)	21 %	21 %	20 %	19 %
Natural gas liquids (MBbls)	20 %	20 %	20 %	20 %
	100 %	100 %	100 %	100 %

	Three Months Ended September 30, 2021				Three Months Ended September 30, 2020			
	Midland Basin	Delaware Basin	Other(1)	Total	Midland Basin	Delaware Basin	Other(2)	Total
Production Data:								
Oil (MBbls)	14,265	6,247	1,546	22,058	8,971	6,627	41	15,639
Natural gas (MMcf)	26,246	16,210	3,115	45,571	17,403	15,003	99	32,505
Natural gas liquids (MBbls)	4,547	2,301	692	7,540	3,087	2,268	22	5,377
Total (MBoe)	23,186	11,250	2,757	37,193	14,958	11,395	80	26,433

	Nine Months Ended September 30, 2021				Nine Months Ended September 30, 2020			
	Midland Basin	Delaware Basin	Other(1)	Total	Midland Basin	Delaware Basin	Other(2)	Total
Production Data:								
Oil (MBbls)	38,065	19,074	3,564	60,703	28,864	21,013	132	50,009
Natural gas (MMcf)	69,822	47,503	6,861	124,186	50,285	45,871	326	96,482
Natural gas liquids (MBbls)	12,146	6,438	1,408	19,992	9,281	6,975	70	16,326
Total (MBoe)	61,848	33,429	6,116	101,393	46,525	35,633	257	82,415

(1) Includes the Eagle Ford Shale, Rockies and High Plains.
(2) Includes the Central Basin Platform, Eagle Ford Shale and Rockies.

Comparison of the Three Months Ended September 30, 2021 and 2020 and Nine Months Ended September 30, 2021 and 2020

Oil, Natural Gas and Natural Gas Liquids Revenues. Our revenues are a function of oil, natural gas and natural gas liquids production volumes sold and average sales prices received for those volumes.

Our oil, natural gas and natural gas liquids revenues for the three months ended September 30, 2021 increased by $1.2 billion, or 168%, to $1.9 billion from $707 million during the three months ended September 30, 2020. Higher average oil prices, and to a lesser extent natural gas and natural gas liquids prices, contributed $0.9 billion of the total increase. The remainder of the overall change is due to a 41% increase in combined volumes sold.

Our oil, natural gas and natural gas liquids revenues for the nine months ended September 30, 2021 increased by $2.7 billion, or 137%, to $4.7 billion from $2.0 billion during the nine months ended September 30, 2020. Higher average oil prices, and to a lesser extent natural gas and natural gas liquids prices, contributed to $2.3 billion of the total increase. The remainder of the overall change is due to a 23% increase in combined volumes sold.

In both cases, higher commodity prices in the 2021 periods compared to the 2020 periods primarily reflect a recovery from historically low prices experienced in 2020 due to the COVID-19 pandemic as discussed in "— *Recent Developments*" above. The increase in production for the 2021 periods compared to the 2020 periods resulted primarily from the Guidon Acquisition and QEP Merger during the first quarter of 2021 and an overall recovery in our drilling and production activities after curtailments in the second quarter of 2020 in response to the COVID-19 pandemic. We expect to hold our oil production levels flat for the foreseeable future.

Lease Operating Expenses. The following table shows lease operating expenses for the three and nine months ended September 30, 2021 and 2020:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2021		2020		2021		2020	
	Amount	Per BOE	Amount	Per BOE	Amount	Per BOE	Amount	Per BOE
	(In millions, except per BOE amounts)							
Lease operating expenses	$ 156	$ 4.19	$ 102	$ 3.86	$ 415	$ 4.09	$ 332	$ 4.03

Lease operating expenses increased by $54 million, or $0.33 per BOE for the third quarter of 2021 compared to the third quarter of 2020 and increased by $83 million, or $0.06 per BOE for the nine months ended September 30, 2021 compared to the nine months ended September 30, 2020. In both cases, this increase is primarily due to an increase in production between periods driven by the Guidon Acquisition and the QEP Merger in the first quarter of 2021. The increase on a per BOE basis is primarily related to the Williston Basin assets acquired in the QEP Merger which have higher lease operating costs per BOE on average than our historical properties.

Production and Ad Valorem Tax Expense. The following table shows production and ad valorem tax expense for the three and nine months ended September 30, 2021 and 2020:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2021		2020		2021		2020	
	Amount	Per BOE	Amount	Per BOE	Amount	Per BOE	Amount	Per BOE
	(In millions, except per BOE amounts)							
Production taxes	$ 98	$ 2.63	$ 36	$ 1.36	$ 245	$ 2.42	$ 97	$ 1.18
Ad valorem taxes	26	0.70	19	0.72	59	0.58	51	0.62
Total production and ad valorem expense	$ 124	$ 3.33	$ 55	$ 2.08	$ 304	$ 3.00	$ 148	$ 1.80
Production taxes as a % of oil, natural gas, and natural gas liquids revenue	5.2 %		5.1 %		5.2 %		4.8 %	

In general, production taxes are directly related to production revenues and are based upon current year commodity prices. Production taxes as a percentage of production revenues increased slightly for the three and nine months ended September 30, 2021 compared to the same periods in 2020 due to the addition of production revenues from the acquired Williston Basin properties which have a higher production tax rate than our other properties. We completed the divestiture of the Williston Basin properties in October 2021.

Ad valorem taxes are based, among other factors, on property values driven by prior year commodity prices. Ad valorem taxes for the three and nine months ended September 30, 2021 as compared to the same periods in 2020 increased by $7 million and $8 million, respectively, primarily due to additional properties acquired in the Guidon acquisition and the QEP Merger.

Gathering and Transportation Expense. The following table shows gathering and transportation expense for the three and nine months ended September 30, 2021 and 2020:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2021		2020		2021		2020	
	Amount	Per BOE	Amount	Per BOE	Amount	Per BOE	Amount	Per BOE
	(In millions, except per BOE amounts)							
Gathering and transportation expense	$ 67	$ 1.80	$ 33	$ 1.25	$ 154	$ 1.52	$ 105	$ 1.27

The increases for gathering and transportation expenses for the three and nine months ended September 30, 2021, compared to the same periods in 2020 are primarily attributable to the increase in production between periods. Additionally, the production added from the QEP Merger has higher average gathering and transportation costs per BOE than our historical properties.

Depreciation, Depletion, Amortization and Accretion. The following table provides the components of our depreciation, depletion, amortization and accretion expense for the three and nine months ended September 30, 2021 and 2020:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
	(In millions, except BOE amounts)			
Depletion of proved oil and natural gas properties	$ 324	$ 273	$ 899	$ 995
Depreciation of midstream assets	11	9	37	29
Depreciation of other property and equipment	4	4	12	12
Asset retirement obligation accretion	2	2	7	5
Depreciation, depletion and amortization expense	$ 341	$ 288	$ 955	$ 1,041
Oil and natural gas properties depletion rate per BOE	$ 8.71	$ 10.33	$ 8.87	$ 12.07

The increase in depletion of proved oil and natural gas properties of $51 million for the three months ended September 30, 2021 as compared to the three months ended September 30, 2020 resulted largely from increased production partially offset by a lower average depletion rate. The decline in rate resulted primarily from higher SEC prices utilized in the reserve calculations in the 2021 period, lengthening the economic life of the reserve base and resulting in higher projected remaining reserve volumes on our wells.

The decrease in depletion of proved oil and natural gas properties of $96 million for the nine months ended September 30, 2021 as compared to the nine months ended September 30, 2020 resulted largely from a reduction in the average depletion rate partially offset by increased production in 2021. The decline in rate resulted primarily from higher SEC oil prices utilized in the reserve calculations in the 2021 period, lengthening the economic life of the reserve base and resulting in higher projected remaining reserve volumes on our wells.

Impairment of Oil and Natural Gas Properties. No impairment expense was recorded for the three and nine months ended September 30, 2021. In connection with the QEP Merger and the Guidon Acquisition, we recorded the oil and natural gas properties acquired at fair value. Pursuant to SEC guidance, we determined the fair value of the properties acquired in the QEP Merger and the Guidon Acquisition clearly exceeded the related full cost ceiling limitation beyond a reasonable doubt. As such, we requested and received a waiver from the SEC to exclude the acquired properties from the first quarter 2021 ceiling test calculation. As a result, no impairment expense related to the QEP Merger and the Guidon Acquisition was recorded for the three months ended March 31, 2021. Had we not received the waiver from the SEC, an impairment charge of approximately $1.1 billion would have been recorded in the first quarter of 2021. The properties acquired in the QEP Merger and the Guidon Acquisition had total unamortized costs at March 31, 2021 of $3.0 billion and $1.1 billion, respectively.

As a result of the sharp decline in commodity prices during 2020, we recorded non-cash ceiling test impairments for the three and nine months ended September 30, 2020 of $1.5 billion and $5.0 billion, respectively, which are included in accumulated depletion, depreciation, amortization and impairment on our condensed consolidated balance sheet.

Impairment charges affect our results of operations but do not reduce our cash flow. In addition to commodity prices, our production rates, levels of proved reserves, future development costs, transfers of unevaluated properties and other factors will determine our actual ceiling test calculation and impairment analysis in future periods. If the trailing 12-month commodity prices fall as compared to the commodity prices used in prior quarters, we may have material write-downs in subsequent quarters. See Note 5—Property and Equipment for further details regarding factors that impact the impairment of oil and natural gas properties.

General and Administrative Expenses. The following table shows general and administrative expenses for the three and nine months ended September 30, 2021 and 2020:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2021		2020		2021		2020	
	Amount	Per BOE	Amount	Per BOE	Amount	Per BOE	Amount	Per BOE
	(In millions, except per BOE amounts)							
General and administrative expenses	$ 24	$ 0.65	$ 11	$ 0.42	$ 62	$ 0.61	$ 37	$ 0.45
Non-cash stock-based compensation	14	0.37	9	0.34	37	0.37	27	0.33
Total general and administrative expenses	$ 38	$ 1.02	$ 20	$ 0.76	$ 99	$ 0.98	$ 64	$ 0.78

The increases in general and administrative expenses for the three and nine months ended September 30, 2021 compared to the three and nine months ended September 30, 2020 were due largely to additional payroll and other employee driven costs of $11 million and $21 million, respectively, related to the QEP Merger and the Guidon Acquisition. Additionally, equity compensation increased by $5 million and $10 million for the three and nine months ended September 30, 2021, respectively, compared to the same periods in 2020.

Merger and Integration Expense. The following tables shows merger and integration expense for the three and nine months ended September 30, 2021 and 2020:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
	(In millions)			
Merger and integration expense	$ —	$ —	$ 77	$ —

Total merger and integration expense for the nine months ended September 30, 2021 includes $68 million in costs incurred for the QEP Merger and $9 million in costs incurred for the Guidon Acquisition. The QEP Merger related expenses primarily consist of $38 million in severance costs and $30 million in banking, legal and advisory fees, and the Guidon Acquisition related expenses consist primarily of advisory and legal fees. See Note 4—Acquisitions and Divestitures for further details regarding the QEP Merger and the Guidon Acquisition.

Net Interest Expense. The following table shows the components of net interest expense for the three and nine months ended September 30, 2021 and 2020:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
	(In millions)			
Revolving credit agreements	$ 2	$ 4	$ 7	$ 17
Senior notes	66	57	197	155
Amortization of debt issuance costs and discounts	5	4	13	9
Other	1	2	5	7
Capitalized interest	(16)	(14)	(51)	(41)
Total	58	53	171	147
Less: interest income	1	—	1	—
Interest expense, net	$ 57	$ 53	$ 170	$ 147

Net interest expense increased by $4 million and $23 million for the three and nine months ended September 30, 2021 compared to the same periods in 2020. In both cases, the increase was primarily due to interest expense related to our May 2020 Notes, Rattler's 5.625% Senior Notes due 2025, the newly issued March 2021 Notes, and to a lesser extent, interest expense incurred on the QEP Notes that remained outstanding following the QEP Merger completed in March 2021. These increases were partially offset by interest cost savings on the repurchases of our 2025 Senior Notes in March 2021 and August 2021, and the reduction in borrowings under our revolving credit agreements during 2021. See Note 7—Debt for further details regarding outstanding borrowings and interest expense.

Derivative Instruments. The following table shows the net gain (loss) on derivative instruments and the net cash receipts (payments) on settlements of derivative instruments for the three and nine months ended September 30, 2021 and 2020:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
	(In millions)			
Gain (loss) on derivative instruments, net	$ (234)	$ (99)	$ (895)	$ 82
Net cash received (paid) on settlements[(1)(2)(3)]	$ (397)	$ (9)	$ (822)	$ 288

(1) The three and nine months ended September 30, 2021 include cash paid on commodity contracts terminated prior to their contractual maturity of $16 million.
(2) The three and nine months ended September 30, 2020 include cash received on commodity contracts terminated prior to their contractual maturity of $6 million and $17 million, respectively.
(3) The nine months ended September 30, 2021 include cash received on interest rate swap contracts terminated prior to their contractual maturity of $80 million.

We are required to recognize all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We have not designated our commodity derivative instruments as hedges for accounting purposes. As a result, we mark our derivative instruments to fair value and recognize the cash and non-cash changes in fair value on derivative instruments in our condensed consolidated statements of operations under the line item captioned "Gain (loss) on derivative instruments, net." As part of the QEP Merger, we received by novation from QEP certain derivative instruments which were included on our balance sheet as of September 30, 2021.

We have designated certain of our interest rate swaps as fair value hedges for accounting purposes. As a result, gains and losses due to changes in the fair value of the interest rate swaps completely offset changes in the fair value of the hedged portion of the underlying debt and no gain or loss is recognized due to hedge ineffectiveness. Changes in fair value are recorded as an adjustment to the carrying value of the 2029 Notes in the condensed consolidated balance sheet. Beginning on December 1, 2021, semi-annual cash settlements of these interest rate swaps will be recorded in interest expense in the condensed consolidated statements of operations.

Provision for (Benefit from) Income Taxes. The following table shows the provision for (benefit from) income taxes for the three and nine months ended September 30, 2021 and 2020:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
	(In millions)			
Provision for (benefit from) income taxes	$ 193	$ (304)	$ 352	$ (902)

The changes in our income tax provision for the three and nine months ended September 30, 2021 compared to the same periods in 2020 were primarily due to the increase in pre-tax income for the three and nine months ended September 30, 2021, partially offset by income tax expense resulting from recording a valuation allowance on Viper's deferred tax assets for the nine months ended September 30, 2021.

Liquidity and Capital Resources

As of September 30, 2021, we had $1.6 billion of availability for future borrowings under the credit agreement and approximately $457 million of cash on hand. Historically, our primary sources of liquidity have been cash flows from operations, proceeds from our public equity offerings, borrowings under the credit agreement and proceeds from the issuance of our senior notes. Our primary uses of capital have been for the acquisition, development and exploration of oil and natural gas properties and return of capital to our stockholders.

As we pursue our business and financial strategy, we regularly consider which capital resources, including cash flow and equity and debt financings, are available to meet our future financial obligations, planned capital expenditure activities and liquidity requirements. Our future ability to grow proved reserves and production will be highly dependent on the capital resources available to us. Continued prolonged volatility in the capital, financial and/or credit markets due to the COVID-19 pandemic, the commodity pricing environment and uncertain macroeconomic conditions may limit our access to, or increase our cost of, capital or make capital unavailable on terms acceptable to us or at all.

Liquidity and Cash Flow

Our cash flows for the nine months ended September 30, 2021 and 2020 are presented below:

	Nine Months Ended September 30,	
	2021	2020
	(In millions)	
Net cash provided by (used in) operating activities	$ 2,777	$ 1,715
Net cash provided by (used in) investing activities	(1,323)	(1,855)
Net cash provided by (used in) financing activities	(1,021)	111
Net increase (decrease) in cash	$ 433	$ (29)

Operating Activities

Our operating cash flow is sensitive to many variables, the most significant of which is the volatility of prices for the oil and natural gas we produce. Prices for these commodities are determined primarily by prevailing market conditions. Regional and worldwide economic activity, weather and other substantially variable factors influence market conditions for these products. These factors are beyond our control and are difficult to predict.

The increase in operating cash flows for the nine months ended September 30, 2021 compared to the same period in 2020 primarily resulted from (i) an increase of $2.7 billion in our total revenues, and (ii) receipt of $152 million in refunds of income taxes receivable related to the carryback of federal net operating losses and the accelerated refund of minimum tax credits allowed under the CARES Act in 2020. These net cash inflows were partially offset by (i) a reduction of $1.1 billion due to making net cash payments of $847 million on our derivative contracts in the nine months ended September 30, 2021 compared to receiving net cash of $288 million on our derivative contracts in the nine months ended September 30, 2020, (ii) an increase in our cash operating expenses of approximately $396 million primarily due to the QEP Merger and the Guidon Acquisition, (iii) an increase of $77 million in our cash paid for interest primarily due to interest payments on senior notes which were issued in 2020 and 2021 and (iv) other working capital changes, primarily due to recording activity for working capital assets and liabilities acquired in the QEP Merger during March 2021. See "— *Results of Operations*" for discussion of significant changes in our revenues and expenses.

Investing Activities

Net cash used in investing activities was $1.3 billion compared to $1.9 billion during the nine months ended September 30, 2021 and 2020, respectively. The majority of our net cash used for investing activities during the nine months ended September 30, 2021 was for the purchase and development of oil and natural gas properties and related assets, including the acquisition of certain leasehold interests as part of the Guidon Acquisition. These expenditures were partially offset by proceeds from the sale of leasehold acreage discussed in Note 4—Acquisitions and Divestitures.

The majority of our net cash used in investing activities during the nine months ended September 30, 2020 was incurred for drilling and completion costs in conjunction with our development program. Our capital expenditures for each period are discussed further below.

Capital Expenditure Activities

Our capital expenditures excluding acquisitions and equity method investments (on a cash basis) were as follows for the specified period:

	Nine Months Ended September 30,	
	2021	2020
	(In millions)	
Drilling, completions and non-operated additions to oil and natural gas properties(1)(2)	$ 987	$ 1,404
Infrastructure additions to oil and natural gas properties	43	96
Additions to midstream assets	23	133
Total	$ 1,053	$ 1,633

(1) During the nine months ended September 30, 2021, in conjunction with our development program, we drilled 163 gross (153 net) operated horizontal wells, of which 135 gross (127 net) wells were in the Midland Basin and 28 gross (26 net) wells were in the Delaware Basin, and turned 205 gross (189 net) operated horizontal wells to production, of which 152 gross (140 net) wells were in the Midland Basin and 49 gross (46 net) wells were in the Delaware Basin.

(2) During the nine months ended September 30, 2020, in conjunction with our development program, we drilled 183 gross (173 net) operated horizontal wells, of which 114 gross (108 net) wells were in the Midland Basin and 69 gross (65 net) wells were in the Delaware Basin, and turned 136 gross (124 net) operated horizontal wells to production, of which 69 gross (61 net) wells were in the Midland Basin and 67 gross (63 net) wells were in the Delaware Basin .

Financing Activities

Net cash used in financing activities for the nine months ended September 30, 2021 was $1.0 billion compared to net cash provided by financing activities for the nine months ended September 30, 2020 of $111 million. During the nine months ended September 30, 2021, the amount used in financing activities was primarily attributable to (i) $2.5 billion paid for the repurchase of principal outstanding on certain senior notes as discussed in *"— Repurchases of Notes"* below, as well as $178 million of additional premiums paid in connection with the repurchases, (ii) $221 million of dividends paid to stockholders, (iii) $94 million of repayments under our credit facilities, net of borrowings, (iv) $72 million in distributions to non-controlling interest, and (v) $85 million of repurchases as part of the share and unit repurchase programs. These cash outflows were partially offset by $2.2 billion in proceeds from the March 2021 Notes and $25 million in net cash receipts from the early settlement of interest rate swaps and commodity derivative contracts that contained an other-than-insignificant financing element.

Net cash provided by financing activities for the nine months ended September 30, 2020 was primarily attributable to $758 million in proceeds, net of repayments, from senior notes and $47 million in proceeds from joint ventures. These cash inflows were partially offset by (i) $321 million of repayments, net of borrowings, under our credit facilities (i) $177 million of dividends to stockholders, (ii) $98 million of share repurchases as part of our previous stock repurchase program, and (iii) $77 million of distributions to non-controlling interest.

Indebtedness

At September 30, 2021, our debt, including the debt of Viper and Rattler, consists of approximately $6.9 billion in aggregate outstanding principal amount of senior notes, $92 million in aggregate outstanding borrowings under revolving credit facilities and $65 million in outstanding amounts due under our DrillCo Agreement. Our revolving credit facilities and significant changes in our outstanding indebtedness during the nine months ended September 30, 2021 are discussed further below. See Note 7—Debt for additional discussion of our outstanding debt at September 30, 2021.

Second Amended and Restated Credit Facility

As discussed in "— *Recent Developments*" on June 2, 2021, we entered into an amendment to the credit agreement. As of September 30, 2021, the maximum credit amount available under the credit agreement was $1.6 billion, with no outstanding borrowings and $1.6 billion available for future borrowings. As of September 30, 2021, there was an aggregate of $3 million in outstanding letters of credit, which reduce available borrowings under the credit agreement on a dollar for dollar basis. During the nine months ended September 30, 2021, the weighted average interest rate on the credit facility was 1.67%.

As of September 30, 2021, we were in compliance with all financial maintenance covenants under the credit agreement.

March 2021 Notes Offering

On March 24, 2021, we issued $650 million of our 2023 Notes, $900 million of our 2031 Notes and $650 million of our 2051 Notes and received proceeds of $2.18 billion, net of $24 million in debt issuance costs and discounts. The net proceeds were primarily used to fund the repurchase of other senior notes outstanding as discussed further below. Interest on the March 2021 Notes is payable semi-annually in March and September, beginning in September 2021.

Repurchases of Notes

Subsequent to the QEP Merger, in March 2021, we repurchased pursuant to tender offers commenced by us approximately $1.65 billion in fair value carrying amount of the QEP Notes for total cash consideration of $1.7 billion, including redemption and early premium fees, which resulted in a loss on extinguishment of debt during the three months ended March 31, 2021 of approximately $47 million. The aggregate fair value of the QEP Notes repurchased consisted of (i) $453 million, or 94.65%, of the outstanding fair value carrying amount of the QEP 2022 Notes, (ii) $663 million, or 98.43%, of the outstanding fair value carrying amount of the QEP 2023 Notes, and (iii) $538 million, or 96.35%, of the outstanding fair value carrying amount of the QEP 2026 Notes.

In March 2021, we also repurchased an aggregate of $368 million principal amount of our 5.375% 2025 Senior Notes, representing approximately 45.97% of the outstanding 2025 Senior Notes, for total cash consideration of $381 million, including redemption and early premium fees. This resulted in a loss on extinguishment of debt during the nine months ended September 30, 2021 of $14 million.

We funded the repurchases of the QEP Notes and 2025 Senior Notes with the proceeds from the March 2021 Notes offering discussed above.

In connection with the tender offers to repurchase the QEP Notes discussed above, we also solicited consents from holders of the QEP Notes to amend the indenture for the QEP Notes to, among other things, eliminate substantially all of the restrictive covenants and related provisions and certain events of default contained in the indenture under which the QEP Notes were issued. We received the requisite number of consents and, on March 23, 2021, entered into a supplemental indenture relating to the QEP Notes adopting these amendments.

In June 2021, we redeemed the remaining $191 million principal amount of the outstanding Energen 4.625% senior notes due on September 1, 2021. We recorded an immaterial pre-tax loss on extinguishment of debt related to the redemption, which included the write-off of unamortized debt discounts associated with the redeemed notes. We funded the redemption with internally generated cash flow from operations as well as proceeds from the divestitures of certain non-core assets as discussed in Note 4—Acquisitions and Divestitures.

In August 2021, we redeemed the remaining $432 million principal amount of our outstanding 5.375% Senior Notes due 2025 for total cash consideration of $449 million, including redemption and early premium fees of $12 million, which resulted in a loss on extinguishment of debt during the three and nine months ended September 30, 2021 of $12 million. We funded the redemption with cash on hand and borrowings under its revolving credit facility.

On November 1, 2021, we redeemed the aggregate $650 million principal amount of our outstanding 2023 Senior Notes at a redemption price equal to 100% of the principal amount, plus accrued and unpaid interest up to, but not including, the redemption date. We funded the redemption with proceeds received from the divestiture of our Williston Basin assets and cash on hand.

Viper's Credit Agreement

The Viper credit agreement, as amended to date, provides for a revolving credit facility in the maximum credit amount of $2.0 billion, with a borrowing base of $580 million as of September 30, 2021, although Viper LLC had elected a commitment amount of $500 million, based on Viper LLC's oil and natural gas reserves and other factors. The borrowing base is scheduled to be redetermined semi-annually in May and November, and is expected to be reaffirmed at $580 million by the lenders during the redetermination in November 2021. As of September 30, 2021, there were $92 million of outstanding borrowings and $408 million available for future borrowings under the Viper credit agreement. In the fourth quarter of 2021, approximately $190.0 million of the cash portion of the Swallowtail Acquisition was funded through borrowings under Viper's credit agreement, reducing the amount that remained available for future borrowings under this facility to $218.0 million as of October 1, 2021. During the three and nine months ended September 30, 2021, the weighted average interest rate on borrowings under the Viper credit agreement was 1.98% and 2.14%, respectively. The Viper credit agreement will mature on June 2, 2025.

As of September 30, 2021, Viper LLC was in compliance with all financial maintenance covenants under the Viper credit agreement.

Rattler's Credit Agreement

The Rattler credit agreement, as amended to date, provides for a revolving credit facility in the maximum credit amount of $600 million, which is expandable to $1.0 billion upon Rattler's election, subject to obtaining additional lender commitments and satisfaction of customary conditions. As of September 30, 2021, there were no outstanding borrowings and $600 million available for future borrowings under the Rattler credit agreement. During the three and nine months ended September 30, 2021, the weighted average interest rate on borrowings under the Rattler credit agreement was 1.34% and 1.38%, respectively. The Rattler credit agreement matures on May 28, 2024.

As of September 30, 2021, Rattler LLC was in compliance with all financial maintenance covenants under the Rattler credit agreement.

Capital Requirements and Sources of Liquidity

Our primary short and long-term liquidity requirements consist primarily of (i) capital expenditures, (ii) payments of contractual obligations, including debt maturities, (iii) dividends and share repurchases, and (iv) working capital obligations.

During the fourth quarter of 2021, we updated our 2021 capital budget to approximately $1.49 billion to $1.53 billion, which represented a decrease at the midpoint of 4% over our previously announced capital budget. This decrease is due to cost control and volume outperformance of our 2021 development plan. We intend to maintain current production levels with less capital and fewer completed wells than were originally expected in our 2021 development plan. We estimate that, of these expenditures, approximately:

- $1.39 billion to $1.42 billion will be spent primarily on drilling and completing and 265 to 275 gross (246 to 256 net) horizontal wells across our operated leasehold acreage in the Northern Midland and Southern Delaware Basins, with an average lateral length of approximately 10,500 feet;

- $40 million will be spent on midstream infrastructure, excluding joint venture investments; and

- $60 million to $70 million will be spent on infrastructure and environmental expenditures, excluding the cost of any leasehold and mineral interest acquisitions.

We do not have a specific acquisition budget since the timing and size of acquisitions cannot be accurately forecasted.

During the nine months ended September 30, 2021, we spent $948 million on drilling and completion, $23 million on midstream, $39 million on non-operated properties and $43 million on infrastructure, for total capital expenditures, excluding acquisitions, of $1,053 million.

The amount and timing of our capital expenditures are largely discretionary and within our control. We could choose to defer a portion of these planned capital expenditures depending on a variety of factors, including but not limited to the success of our drilling activities, prevailing and anticipated prices for oil and natural gas, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other interest owners. We are currently operating nine drilling rigs and three completion crews. We currently continue to execute on our strategy to hold oil production flat while using cash flow from operations to reduce debt, strengthen our balance sheet and return capital to our stockholders. We will continue monitoring commodity prices and overall market conditions and can adjust our rig cadence and our capital expenditure budget in response to changes in commodity prices and overall market conditions.

In September 2021, our board of directors approved a stock repurchase program to acquire up to $2 billion of our outstanding common stock. We repurchased approximately $22 million of our common stock during the nine months ended September 30, 2021, with approximately $1.98 billion remaining available for future repurchases under this program. We intend to continue to purchase shares under this repurchase program opportunistically with available funds primarily from cash flow from operations and liquidity events such as the sale of assets while maintaining sufficient liquidity to fund our capital expenditure programs.

Based upon current oil and natural gas prices and production expectations for 2021, we believe that our cash flow from operations, cash on hand and borrowings under our revolving credit facility will be sufficient to fund our operations through the 12-month period following the filing of this report and thereafter. However, future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices, and significant additional capital expenditures will be required to more fully develop our properties. We cannot assure you that the needed capital will be available on acceptable terms or at all. Further, our 2021 capital expenditure budget does not allocate any funds for leasehold interest and property acquisitions.

Guarantor Financial Information

In connection with the merger of certain of the Company’s wholly owned subsidiaries in an internal subsidiary restructuring on June 30, 2021, Diamondback E&P became the successor borrower to O&G under the credit agreement, the successor issuer of the Energen Medium-Term Notes and the sole guarantor under the indentures governing the December 2019 Notes, the May 2020 Notes, the 2025 Senior Notes and the March 2021 Notes.

Guarantees are “full and unconditional,” as that term is used in Regulation S-X, Rule 3-10(b)(3), except that such guarantees will be released or terminated in certain circumstances set forth in the 2019 Indenture and the 2025 Indenture, such as, with certain exceptions, (1) in the event Diamondback E&P (or all or substantially all of its assets) is sold or disposed of, (2) in the event Diamondback E&P ceases to be a guarantor of or otherwise be an obligor under certain other indebtedness, and (3) in connection with any covenant defeasance, legal defeasance or satisfaction and discharge of the relevant indenture. The 2025 Indenture was terminated in connection with the early redemption of the remaining $432 million principal amount of our 2025 Senior Notes in the third quarter of 2021.

Diamondback E&P’s guarantees of the December 2019 Notes, the May 2020 Notes, and the March 2021 Notes are senior unsecured obligations and rank senior in right of payment to any of its future subordinated indebtedness, equal in right of payment with all of its existing and future senior indebtedness, including its obligations under its revolving credit facility, and effectively subordinated to any of its existing and future secured indebtedness, to the extent of the value of the collateral securing such indebtedness.

The rights of holders of the Senior Notes against Diamondback E&P may be limited under the U.S. Bankruptcy Code or state fraudulent transfer or conveyance law. Each guarantee contains a provision intended to limit Diamondback E&P’s liability to the maximum amount that it could incur without causing the incurrence of obligations under its guarantee to be a fraudulent conveyance. However, there can be no assurance as to what standard a court will apply in making a determination of the maximum liability of Diamondback E&P. Moreover, this provision may not be effective to protect the guarantee from being voided under fraudulent conveyance laws. There is a possibility that the entire guarantee may be set aside, in which case the entire liability may be extinguished.

The following tables present summarized financial information for Diamondback Energy, Inc., as the parent, and Diamondback E&P, as the guarantor subsidiary, on a combined basis after elimination of (i) intercompany transactions and balances between the parent and the guarantor subsidiary and (ii) equity in earnings from and investments in any subsidiary that is a non-guarantor. The information is presented in accordance with the requirements of Rule 13-01 under the SEC's Regulation S-X. The financial information may not necessarily be indicative of results of operations or financial position had the guarantor subsidiary operated as an independent entity.

	September 30, 2021		December 31, 2020	
Summarized Balance Sheets:	(In millions)			
Assets:				
Current assets	$	979	$	308
Property and equipment, net	$	14,558	$	6,934
Other noncurrent assets	$	44	$	6
Liabilities:				
Current liabilities	$	1,675	$	355
Intercompany accounts payable, non-guarantor subsidiary	$	468	$	335
Long-term debt	$	5,748	$	4,293
Other noncurrent liabilities	$	1,270	$	886

	Nine Months Ended September 30, 2021	
Summarized Statement of Operations:	(In millions)	
Revenues	$	3,516
Income (loss) from operations	$	1,964
Net income (loss)	$	658

Contractual Obligations

In addition to the changes in debt discussed in *"—Indebtedness"* above and in Note 7—Debt included in the notes to the condensed consolidated financial statements included elsewhere in this report, we acquired certain contractual obligations during the nine months ended September 30, 2021 in conjunction with the QEP Merger including an aggregate of approximately $68 million in various transportation, gathering and purchase commitments. There were no other significant changes in our contractual obligations from those disclosed in our Annual Report on Form 10-K for the year ended December 31, 2020.

Critical Accounting Policies and Estimates

There have been no changes in our critical accounting policies from those disclosed in our Annual Report on Form 10-K for the year ended December 31, 2020.

Off-Balance Sheet Arrangements

We had no material off-balance sheet arrangements as of September 30, 2021. Please read Note 13—Commitments and Contingencies included in the notes to the condensed consolidated financial statements included elsewhere in this report, for a discussion of our commitments and contingencies, which are not recognized in the balance sheets under GAAP.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk

Our major market risk exposure in our exploration and production business is in the pricing applicable to our oil and natural gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our natural gas production. Pricing for oil and natural gas production has been volatile and unpredictable for several years. Although demand and market prices for oil and natural gas have recently increased due to the rising energy use, easing of the COVID-19 pandemic and the improvements in the U.S. economic activity, we cannot predict events that may lead to future price volatility and the near term energy outlook remains subject to heightened levels of uncertainty. Further, the prices we receive for production depend on many other factors outside of our control.

We use derivatives, including swaps, basis swaps, puts, swaptions, roll swaps, and costless collars, to reduce price volatility associated with certain of our oil and natural gas sales.

At September 30, 2021, we had a net liability derivative position related to our commodity price derivatives of $618 million, related to our commodity price risk derivatives. Utilizing actual derivative contractual volumes under our commodity price derivatives as of September 30, 2021, a 10% increase in forward curves associated with the underlying commodity would have increased the net liability position by $256 million to $874 million, while a 10% decrease in forward curves associated with the underlying commodity would have decreased the net liability position by $218 million to $400 million. However, any cash derivative gain or loss would be substantially offset by a decrease or increase, respectively, in the actual sales value of production covered by the derivative instrument.

In our midstream operations business, we have indirect exposure to commodity price risk in that persistent low commodity prices may cause us or Rattler's other customers to delay drilling or shut in production, which would reduce the volumes available for gathering and processing by our infrastructure assets. If we or Rattler's other customers delay drilling or temporarily shut in production due to persistently low commodity prices or for any other reason, our revenue in the midstream operations segment could decrease, as Rattler's commercial agreements do not contain minimum volume commitments.

For additional information on our open commodity derivative instruments at September 30, 2021, see Note 11—Derivatives.

Counterparty and Customer Credit Risk

Our principal exposures to credit risk are due to the concentration of receivables from the sale of our oil and natural gas production (approximately $712 million at September 30, 2021), and to a lesser extent, receivables resulting from joint interest receivables (approximately $99 million at September 30, 2021).

We do not require our customers to post collateral, and the failure or inability of our significant customers to meet their obligations to us due to their liquidity issues, bankruptcy, insolvency or liquidation may adversely affect our financial results.

Joint operations receivables arise from billings to entities that own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we intend to drill. We have little ability to control whether these entities will participate in our wells.

Interest Rate Risk

We are subject to market risk exposure related to changes in interest rates on our indebtedness under our revolving credit facilities and changes in the fair value of our fixed-rate debt. The terms of the credit agreement provide for interest on borrowings at a floating rate equal to an alternative base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.5% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.25% to 1.125% per annum in the case of the alternative base rate and from 1.25% to 2.125% per annum in the case of LIBOR, in each case based on the pricing level. The pricing level depends on certain rating agencies' ratings of our long-term senior unsecure debt. We believe significant interest rate changes would not have a material near-term impact on our future earnings or cash flows. For additional information on our variable interest rate debt at September 30, 2021, see Note 7—Debt.

Historically, we have at times used interest rates swaps to manage our exposure to (i) interest rate changes on our floating-rate date and (ii) fair value changes on our fixed-rate debt. At September 30, 2021, we have interest rate swap agreements for a notional amount of $1.2 billion to manage the impact of market interest rates on interest expense. These interest rate swaps have been designated as fair value hedges of the Company's $1.2 billion 3.50% fixed rate senior notes due

2029 whereby we will receive the fixed rate of interest and will pay an average variable rate of interest based on three month LIBOR plus 2.1865%. For additional information on our interest rate swaps, see Note 11—Derivatives.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Control and Procedures. Under the direction of our Chief Executive Officer and Chief Financial Officer, we have established disclosure controls and procedures, as defined in Rule 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended, or the Exchange Act, that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. The disclosure controls and procedures are also intended to ensure that such information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures. In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives. In addition, the design of disclosure controls and procedures must reflect the fact that there are resource constraints and that management is required to apply judgment in evaluating the benefits of possible controls and procedures relative to their costs.

As of September 30, 2021, an evaluation was performed under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Exchange Act. Based upon our evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that as of September 30, 2021, our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting. In July 2021, we implemented an enterprise resource planning system covering various financial and accounting processes. As a result of this implementation, certain internal controls over financial reporting have been automated, modified or implemented to address the new environment associated with the implementation of this system. We believe we have maintained appropriate internal control over financial reporting during the implementation and believe this new system will strengthen our internal control system. However, there are inherent risks in implementing any new system, and we will continue to evaluate these control changes as part of our assessment of internal control over financial reporting throughout 2021. There have not been any changes in our internal control over financial reporting that occurred during the quarter ended September 30, 2021, that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

PART II

ITEM 1. LEGAL PROCEEDINGS

We are a party to various routine legal proceedings, disputes and claims arising in the ordinary course of our business, including those that arise from interpretation of federal and state laws and regulations affecting the natural gas and crude oil industry, personal injury claims, title disputes, royalty disputes, contract claims, contamination claims relating to oil and natural gas exploration and development and environmental claims, including claims involving assets previously sold to third parties and no longer part of our current operations. While the ultimate outcome of the pending proceedings, disputes or claims, and any resulting impact on us, cannot be predicted with certainty, we believe that none of these matters, if ultimately decided adversely, will have a material adverse effect on our financial condition, results of operations or cash flows. See Note 13—Commitments and Contingencies.

ITEM 1A. RISK FACTORS

Our business faces many risks. Any of the risks discussed in this report and our other SEC filings could have a material impact on our business, financial position or results of operations. Additional risks and uncertainties not presently known to us or that we currently believe to be immaterial may also materially impair our business operations, financial condition or future results.

As of the date of this filing, we continue to be subject to the risk factors previously disclosed in Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2020, filed with the SEC on February 25, 2021, and in subsequent filings we make with the SEC. There have been no material changes in our risk factors from those described in our Annual Report on Form 10-K for the year ended December 31, 2020.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Unregistered Sales of Equity Securities

None.

Issuer Repurchases of Equity Securities

Our common stock repurchase activity for the nine months ended September 30, 2021 was as follows:

Period	Total Number of Shares Purchased(1)	Average Price Paid Per Share(2)	Total Number of Shares Purchased as Part of Publicly Announced Plan	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plan(3)
	($ In millions, except per share amounts, shares in thousands)			
July 1, 2021 - July 31, 2021	—	$ —	—	$ —
August 1, 2021 - August 31, 2021	—	$ —	—	$ —
September 1, 2021 - September 30, 2021	268	$ 82.02	268	$ 1,978
Total	268	$ 82.02	268	

(1) Includes shares of common stock repurchased from employees in order to satisfy tax withholding requirements. Such shares are cancelled and retired immediately upon repurchase.
(2) The average price paid per share includes any commissions paid to repurchase stock.
(3) In September 2021, the Company's board of directors authorized a $2 billion common stock repurchase program. The stock repurchase program has no time limit and may be suspended, modified, or discontinued by the board of directors at any time.

ITEM 6. EXHIBITS

EXHIBIT INDEX

Exhibit Number	Description
3.1	Amended and Restated Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.1 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 16, 2012).
3.2	Certificate of Amendment No. 1 of the Amended and Restated Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on December 12, 2016).
3.3	Certificate of Amendment No. 2 to the Amended and Restated Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on June 8, 2021).
3.4	Second Amended and Restated Bylaws of the Company (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on November 19, 2019).
4.1	Specimen certificate for shares of common stock, par value $0.01 per share, of the Company (incorporated by reference to Exhibit 4.1 to Amendment No. 4 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on August 20, 2012).
4.2	Registration Rights Agreement, dated as of February 26, 2021, by and among the Company, Guidon Operating LLC and Guidon Energy Holdings LP (incorporated by reference to Exhibit 4.3 to the Company's Registration Statement on Form S-3, File No. 333-255731, filed by the Company with the SEC on May 3, 2021.
4.3	Letter Agreement, dated as of April 27, 2021, by and among the Company, Guidon Operating LLC and Guidon Energy Holdings LP relating to the Registration Rights Agreement referenced as Exhibit 4.2 hereto (incorporated by reference to Exhibit 4.4 to the Company's Registration Statement on Form S-3, File No. 333-255731, filed by the Company with the SEC on May 3, 2021).
22.1	List of Issuers and Guarantor Subsidiaries (incorporated by reference to Exhibit 22.1 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on August 5, 2021).
31.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
32.1**	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
32.2**	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
101	The following financial information from the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2021, formatted in Inline XBRL: (i) Condensed Consolidated Balance Sheets, (ii) Condensed Consolidated Statements of Operations, (iii) Condensed Consolidated Statement of Changes in Stockholders' Equity, (iv) Condensed Consolidated Statements of Cash Flows and (v) Condensed Notes to Consolidated Financial Statements.
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101).

* Filed herewith.

** The certifications attached as Exhibit 32.1 and Exhibit 32.2 accompany this Quarterly Report on Form 10-Q pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, and shall not be deemed "filed" by the Registrant for purposes of Section 18 of the Securities Exchange Act of 1934, as amended.

SIGNATURES

Pursuant to the requirements of the Securities and Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

DIAMONDBACK ENERGY, INC.

Date:	November 4, 2021	/s/ Travis D. Stice
		Travis D. Stice Chief Executive Officer (Principal Executive Officer)
Date:	November 4, 2021	/s/ Kaes Van't Hof
		Kaes Van't Hof Chief Financial Officer (Principal Financial Officer)