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, 2023
OR

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

For the transition period from to
Commission file number: 001-38005

Kimbell Royalty Partners, LP
(Exact name of registrant as specified in its charter)

Delaware	**1311**	**47-5505475**
(State or other jurisdiction of incorporation or organization)	(Primary Standard Industrial Classification Code Number)	(I.R.S. Employer Identification No.)

777 Taylor Street, Suite 810
Fort Worth, Texas 76102
(817) 945-9700
(Address, including zip code, and telephone number, including area code, of registrant's principal executive offices)

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

Title of each class:	Trading symbol(s)	Name of exchange on which registered:
Common Units Representing Limited Partner Interests	KRP	New York Stock Exchange

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

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

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

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

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

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

As of October 27, 2023, the registrant had outstanding 73,851,458 common units representing limited partner interests and 20,847,295 Class B units representing limited partner interests.

KIMBELL ROYALTY PARTNERS, LP
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PART I – FINANCIAL INFORMATION

Item 1. Consolidated Financial Statements (Unaudited)

KIMBELL ROYALTY PARTNERS, LP
CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2023	December 31, 2022
ASSETS		
Current assets		
Cash and cash equivalents	$ 39,528,859	$ 24,635,718
Oil, natural gas and NGL receivables	61,320,286	46,993,711
Derivative assets	1,489,189	—
Accounts receivable and other current assets	2,855,653	3,562,912
Total current assets	105,193,987	75,192,341
Property and equipment, net	681,285	953,781
Oil and natural gas properties		
Oil and natural gas properties, using full cost method of accounting ($338,840,127 and $207,695,343 excluded from depletion at September 30, 2023 and December 31, 2022, respectively)	2,048,160,125	1,465,985,718
Less: accumulated depreciation, depletion and impairment	(772,711,451)	(712,716,951)
Total oil and natural gas properties, net	1,275,448,674	753,268,767
Right-of-use assets, net	2,274,148	2,525,323
Derivative assets	134,841	754,786
Loan origination costs, net	6,051,974	3,004,104
Assets of consolidated variable interest entities:		
Cash	—	390,850
Investments held in trust	—	240,621,146
Prepaid expenses	—	35,201
Total assets	$ 1,389,784,909	$ 1,076,746,299
LIABILITIES, MEZZANINE EQUITY AND UNITHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$ 3,186,244	$ 1,210,337
Other current liabilities	10,541,101	4,909,510
Derivative liabilities	1,418,027	12,646,720
Total current liabilities	15,145,372	18,766,567
Operating lease liabilities, excluding current portion	1,977,931	2,236,361
Derivative liabilities	1,527,330	432,142
Long-term debt	310,400,000	233,015,911
Other liabilities	229,167	322,917
Liabilities of consolidated variable interest entities:		
Other current liabilities	—	512,725
Deferred underwriting commissions	—	8,050,000
Total liabilities	329,279,800	263,336,623
Commitments and contingencies (Note 17)		
Mezzanine equity:		
Series A preferred units (325,000 units and zero units issued and outstanding as of September 30, 2023 and December 31, 2022, respectively)	314,028,929	—
Redeemable non-controlling interest in Kimbell Tiger Acquisition Corporation	—	236,900,000
Kimbell Royalty Partners, LP unitholders' equity:		
Common units (73,851,458 units and 64,231,833 units issued and outstanding as of September 30, 2023 and December 31, 2022, respectively)	695,096,257	601,841,776
Class B units (20,847,295 and 15,484,400 units issued and outstanding as of September 30, 2023 and December 31, 2022, respectively)	1,042,365	774,220
Total Kimbell Royalty Partners, LP unitholders' equity	696,138,622	602,615,996
Non-controlling interest (deficit) in OpCo	50,337,558	(26,106,320)
Total unitholders' equity	746,476,180	576,509,676
Total liabilities, mezzanine equity and unitholders' equity	$ 1,389,784,909	$ 1,076,746,299

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

KIMBELL ROYALTY PARTNERS, LP
CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	**2022**	**2023**	**2022**
Revenue				
Oil, natural gas and NGL revenues	$ 69,237,603	$ 73,867,992	$ 183,635,976	$ 217,543,364
Lease bonus and other income	2,543,240	171,702	5,021,766	2,039,154
(Loss) gain on commodity derivative instruments, net	(4,576,570)	(1,116,722)	6,215,265	(40,194,369)
Total revenues	67,204,273	72,922,972	194,873,007	179,388,149
Costs and expenses				
Production and ad valorem taxes	4,986,878	4,518,580	14,669,037	13,542,285
Depreciation and depletion expense	23,060,163	11,326,791	60,280,666	33,359,915
Marketing and other deductions	3,508,500	3,068,244	9,177,998	10,639,314
General and administrative expense	10,358,674	7,482,814	26,562,100	21,938,249
Consolidated variable interest entities related:				
General and administrative expense	—	527,634	927,699	1,857,593
Total costs and expenses	41,914,215	26,924,063	111,617,500	81,337,356
Operating income	25,290,058	45,998,909	83,255,507	98,050,793
Other income (expense)				
Equity income in affiliate	—	23,727	—	3,658,460
Interest expense	(6,680,661)	(3,667,534)	(18,485,183)	(9,868,679)
Loss on extinguishment of debt	—	—	(480,244)	—
Other income (expense)	—	76,873	(180,765)	4,043,530
Consolidated variable interest entities related:				
Interest earned on marketable securities in trust account	—	1,188,256	3,508,691	1,512,777
Net income before income taxes	18,609,397	43,620,231	67,618,006	97,396,881
Income tax expense (benefit)	128,359	(224,883)	2,440,399	1,850,357
Net income	18,481,038	43,845,114	65,177,607	95,546,524
Distribution and accretion on Series A preferred units	(1,040,572)	—	(1,040,572)	—
Net income and distributions and accretion on Series A preferred units attributable to non-controlling interests	(3,839,401)	(5,493,117)	(13,700,261)	(11,975,886)
Distribution on Class B units	(20,854)	(8,211)	(67,939)	(34,032)
Net income attributable to common units of Kimbell Royalty Partners, LP	$ 13,580,211	$ 38,343,786	$ 50,368,835	$ 83,536,606
Net income per unit attributable to common units of Kimbell Royalty Partners, LP				
Basic	$ 0.20	$ 0.69	$ 0.80	$ 1.26
Diluted	$ 0.19	$ 0.59	$ 0.78	$ 1.00
Weighted average number of common units outstanding				
Basic	68,540,786	55,434,641	64,807,590	52,302,235
Diluted	94,969,077	65,543,412	85,739,813	65,397,463

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

KIMBELL ROYALTY PARTNERS, LP
CONSOLIDATED STATEMENTS OF CHANGES IN UNITHOLDERS' EQUITY
(Unaudited)

	Nine Months Ended September 30, 2023					
	Common Units	Amount	Class B Units	Amount	Non-controlling Interest in OpCo	Total
Balance at January 1, 2023	64,231,833	$601,841,776	15,484,400	$ 774,220	$ (26,106,320)	$576,509,676
Restricted units repurchased for tax withholding	(279,662)	(4,851,962)	—	—	—	(4,851,962)
Unit-based compensation	998,162	3,170,000	—	—	—	3,170,000
Distributions to unitholders	—	(31,176,160)	—	—	(7,436,615)	(38,612,775)
Distribution on Class B units	—	(15,484)	—	—	—	(15,484)
Net income	—	23,336,120	—	—	5,563,418	28,899,538
Balance at March 31, 2023	64,950,333	592,304,290	15,484,400	774,220	(27,979,517)	565,098,993
Units issued for acquisition	557,302	8,654,900	5,369,218	268,461	83,383,956	92,307,317
Unit-based compensation	—	3,289,740	—	—	—	3,289,740
Distributions to unitholders	—	(22,732,617)	—	—	(5,349,476)	(28,082,093)
Distribution on Class B units	—	(31,601)	—	—	—	(31,601)
Accretion of redeemable non-controlling interest in Kimbell Tiger Acquisition Corporation and write-off of deferred underwriting commissions	—	1,192,969	—	—	379,768	1,572,737
Net income	—	13,499,589	—	—	4,297,442	17,797,031
Balance at June 30, 2023	65,507,635	596,177,270	20,853,618	1,042,681	54,732,173	651,952,124
Common units issued for equity offering	8,337,500	110,711,383	—	—	—	110,711,383
Conversion of Class B units to common units	6,323	101,105	(6,323)	(316)	(101,105)	(316)
Unit-based compensation	—	3,325,891	—	—	—	3,325,891
Distributions to unitholders	—	(28,799,603)	—	—	(8,132,911)	(36,932,514)
Distribution and accretion on Series A preferred units	—	(811,497)	—	—	(229,075)	(1,040,572)
Distribution on Class B units	—	(20,854)	—	—	—	(20,854)
Net income	—	14,412,562	—	—	4,068,476	18,481,038
Balance at September 30, 2023	73,851,458	$695,096,257	20,847,295	$ 1,042,365	$ 50,337,558	$746,476,180

KIMBELL ROYALTY PARTNERS, LP
CONSOLIDATED STATEMENTS OF CHANGES IN UNITHOLDERS' EQUITY — (Continued)
(Unaudited)

	Nine Months Ended September 30, 2022						
	Common Units	Amount	Class B Units	Amount	Non-controlling Interest in OpCo	Non-controlling Interest in TGR	Total
Balance at January 1, 2022	47,162,773	$328,717,841	17,611,579	$ 880,579	$ 19,251,361	$ —	$348,849,781
Costs associated with equity offering	—	(325,508)	—	—	—	—	(325,508)
Conversion of Class B units to common units	9,357,919	161,424,103	(9,357,919)	(467,896)	(161,424,103)	—	(467,896)
Restricted units repurchased for tax withholding	(193,604)	(3,344,828)	—	—	—	—	(3,344,828)
Unit-based compensation	963,835	2,194,342	—	—	—	—	2,194,342
Distributions to unitholders	—	(17,450,226)	—	—	(6,516,284)	—	(23,966,510)
Distribution on Class B units	—	(17,610)	—	—	—	—	(17,610)
Proceeds from issuance of TGR public warrants	—	—	—	—	—	11,500,000	11,500,000
Accretion of redeemable non-controlling interest in Kimbell Tiger Acquisition Corporation	—	(16,325,799)	—	—	(2,351,988)	(11,500,000)	(30,177,787)
Net income	—	7,348,567	—	—	1,058,677	—	8,407,244
Balance at March 31, 2022	57,290,923	462,220,882	8,253,660	412,683	(149,982,337)	—	312,651,228
Conversion of Class B units to common units	42,081	722,952	(42,081)	(2,104)	(722,952)	—	(2,104)
Forfeitures of restricted units	(1,171)	(19,813)	—	—	—	—	(19,813)
Unit-based compensation	—	2,949,491	—	—	—	—	2,949,491
Distributions to unitholders	—	(26,945,962)	—	—	(3,859,442)	—	(30,805,404)
Distribution on Class B units	—	(8,211)	—	—	—	—	(8,211)
Accretion of redeemable non-controlling interest in Kimbell Tiger Acquisition Corporation	—	(1,519,432)	—	—	(217,627)	—	(1,737,059)
Net income	—	37,870,074	—	—	5,424,092	—	43,294,166
Balance at June 30, 2022	57,331,833	475,269,981	8,211,579	410,579	(149,358,266)	—	326,322,294
Unit-based compensation	—	2,981,903	—	—	—	—	2,981,903
Distributions to unitholders	—	(31,532,508)	—	—	(4,764,169)	—	(36,296,677)
Distribution on Class B units	—	(8,211)	—	—	—	—	(8,211)
Net income	—	38,351,997	—	—	5,493,117	—	43,845,114
Balance at September 30, 2022	57,331,833	$485,063,162	8,211,579	$ 410,579	$ (148,629,318)	$ —	$336,844,423

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

KIMBELL ROYALTY PARTNERS, LP
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30,	
	2023	2022
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 65,177,607	$ 95,546,524
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and depletion expense	60,280,666	33,359,915
Amortization of right-of-use assets	251,175	237,839
Amortization of loan origination costs	1,414,074	1,381,717
Loss on extinguishment of debt	480,244	—
Equity income in affiliate	—	(3,658,460)
Cash distribution from affiliate	—	3,770,651
Forfeiture of restricted units	—	(19,813)
Unit-based compensation	9,785,631	8,125,736
Gain on derivative instruments, net of settlements	(11,002,749)	(1,271,103)
Changes in operating assets and liabilities:		
Oil, natural gas and NGL receivables	(14,326,575)	(11,240,327)
Accounts receivable and other current assets	707,259	455,642
Accounts payable	1,014,264	63,161
Other current liabilities	5,631,591	3,099,504
Operating lease liabilities	(258,430)	(241,314)
Consolidated variable interest entities related:		
Interest earned on marketable securities in trust account	(3,508,691)	(1,512,777)
Other assets and liabilities	(687,353)	(91,005)
Net cash provided by operating activities	114,958,713	128,005,890
CASH FLOWS FROM INVESTING ACTIVITIES		
Purchases of property and equipment	(107,420)	(118,614)
Purchase of oil and natural gas properties	(490,135,551)	(443,977)
Proceeds from trust of variable interest entity	930,850	—
Cash distribution from affiliate	—	3,465,376
Consolidated variable interest entities related:		
Cash paid for transaction costs	31,553	—
Cash received from investments held in trust	243,167,434	—
Investment in marketable securities	—	(236,900,000)
Net cash used in investing activities	(246,113,134)	(233,997,215)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from the issuance of Series A preferred units, net of issuance costs	313,950,000	—
Proceeds from equity offering, net of issuance costs	110,711,383	—
Costs associated with equity offering	—	(325,508)
Contributions from Class B unitholders	268,461	—
Redemption of Class B contributions on converted units	(316)	(470,000)
Distributions to common unitholders	(82,708,380)	(75,928,696)
Distribution to OpCo unitholders	(20,919,002)	(15,139,895)
Distribution on Class B units	(67,939)	(34,032)
Borrowings on long-term debt	201,084,089	43,200,000
Repayments on long-term debt	(123,700,000)	(56,400,000)
Payment of loan origination costs	(4,942,188)	(435,141)
Restricted units repurchased for tax withholding	(4,851,962)	(3,344,828)
Consolidated variable interest entities related:		
Proceeds from initial public offering of Kimbell Tiger Operating Company	—	227,585,000
Payment of underwriting commissions with equity offering of Kimbell Tiger Operating Company, net of adjustments	—	(2,661,288)
Redemption of Kimbell Tiger Acquisition Corporation equity units	(243,167,434)	—
Net cash provided by financing activities	145,656,712	116,045,612
NET INCREASE IN CASH AND CASH EQUIVALENTS	14,502,291	10,054,287
CASH AND CASH EQUIVALENTS, beginning of period	25,026,568	7,052,414
CASH AND CASH EQUIVALENTS, end of period	$ 39,528,859	$ 17,106,701

KIMBELL ROYALTY PARTNERS, LP
CONSOLIDATED STATEMENTS OF CASH FLOWS — (Continued)
(Unaudited)

	Nine Months Ended September 30, 2023		Nine Months Ended September 30, 2022	
Supplemental cash flow information:				
Cash paid for interest	$	16,920,473	$	8,032,309
Cash paid for taxes	$	—	$	3,067,374
Non-cash investing and financing activities:				
Units issued in exchange for oil and natural gas properties	$	92,038,856	$	—
Noncash deemed distribution to Series A preferred units	$	78,929	$	—
Recognition of tenant improvement asset	$	93,750	$	93,751
Consolidated variable interest entities related:				
Reduction of deferred underwriting commission associated with redemption of Kimbell Tiger Acquisition Corporation equity units	$	(8,050,000)	$	—
Deferred underwriting commissions	$	—	$	8,050,000

	Nine Months Ended September 30, 2023		Nine Months Ended September 30, 2022	
Reconciliation of Cash and Cash Equivalents and Cash Held at Consolidated Variable Interest Entities to the Consolidated Statements of Cash Flows				
Cash and cash equivalents	$	39,528,859	$	16,554,722
Cash held at consolidated variable interest entities		—		551,979
	$	39,528,859	$	17,106,701

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

Unless the context otherwise requires, references to "Kimbell Royalty Partners, LP," the "Partnership," or like terms refer to Kimbell Royalty Partners, LP and its subsidiaries. References to the "Operating Company" or "OpCo" refer to Kimbell Royalty Operating, LLC. References to the "General Partner" refer to Kimbell Royalty GP, LLC. References to "Kimbell Operating" refer to Kimbell Operating Company, LLC, a wholly owned subsidiary of the General Partner. References to the "Sponsors" refer to affiliates of the Partnership's founders, Ben J. Fortson, Robert D. Ravnaas, Brett G. Taylor and Mitch S. Wynne, respectively. References to the "Contributing Parties" refer to all entities and individuals, including certain affiliates of the Sponsors, that contributed, directly or indirectly, certain mineral and royalty interests to the Partnership.

NOTE 1—ORGANIZATION AND BASIS OF PRESENTATION

Organization

Kimbell Royalty Partners, LP is a Delaware limited partnership formed in 2015 to own and acquire mineral and royalty interests in oil and natural gas properties throughout the United States. The Partnership has elected to be taxed as a corporation for United States federal income tax purposes. As an owner of mineral and royalty interests, the Partnership is entitled to a portion of the revenues received from the production of oil, natural gas and associated natural gas liquids ("NGL") from the acreage underlying its interests, net of post-production expenses and taxes. The Partnership is not obligated to fund drilling and completion costs, lease operating expenses or plugging and abandonment costs at the end of a well's productive life. The Partnership's primary business objective is to provide increasing cash distributions to unitholders resulting from acquisitions from third parties, its Sponsors and the Contributing Parties, and from organic growth through the continued development by working interest owners of the properties in which it owns an interest.

Basis of Presentation

The accompanying unaudited interim consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") for interim financial information and with the instructions to Form 10-Q and pursuant to the rules and regulations of the U.S. Securities and Exchange Commission (the "SEC"). As a result, the accompanying unaudited interim consolidated financial statements do not include all disclosures required for complete annual financial statements prepared in conformity with GAAP. Accordingly, the accompanying unaudited interim consolidated financial statements and related notes should be read in conjunction with the Partnership's Annual Report on Form 10-K for the year ended December 31, 2022 (the "2022 Form 10-K"), which contains a summary of the Partnership's significant accounting policies and other disclosures. In the opinion of management of the General Partner, the unaudited interim consolidated financial statements contain all adjustments necessary to fairly present the financial position and results of operations for the interim periods in accordance with GAAP and all adjustments are of a normal recurring nature. The accompanying unaudited interim consolidated financial statements include the accounts of the Partnership and its consolidated subsidiaries. All material intercompany balances and transactions are eliminated in consolidation. The results of operations for any interim period are not necessarily indicative of the results to be expected for the full year.

Use of Estimates

Preparation of the Partnership's financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts in the financial statements and notes. Actual results could differ from those estimates.

Segment Reporting

The Partnership operates in a single operating and reportable segment. Operating segments are defined as components of an enterprise for which separate financial information is evaluated regularly by the chief operating decision maker in deciding how to allocate resources and assess performance. The Partnership's chief operating decision maker allocates resources and assesses performance based upon financial information of the Partnership as a whole.

Russia / Ukraine Conflict and Conflict in the Middle East

In February 2022, Russia invaded Ukraine and is still engaged in active armed conflict against the country. In October 2023, armed active conflict began in the Middle East and is still active. These conflicts and the sanctions imposed in response have led to regional instability and caused dramatic fluctuations in global financial markets and have increased the level of global economic and political uncertainty, including uncertainty about world-wide oil supply and demand, which in turn has increased volatility in commodity prices. To date, the Partnership has not experienced a material impact to operations or the consolidated financial statements as a result of these conflicts; however, the Partnership will continue to monitor for events that could materially impact them.

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Significant Accounting Policies

For a description of the Partnership's significant accounting policies, see Note 2 of the consolidated financial statements included in the Partnership's 2022 Form 10-K, as well as the items noted below. There have been no substantial changes in such policies or the application of such policies during the three and nine months ended September 30, 2023.

Consolidation

The Partnership analyzes whether it has a variable interest in an entity and whether that entity is a variable interest entity ("VIE") to determine whether it is required to consolidate those entities. The Partnership performs the variable interest analysis for all entities in which it has a potential variable interest, which primarily consist of all entities with respect to which the Partnership serves as the sponsor, general partner or managing member, and general partner entities not wholly owned by the Partnership. If the Partnership has a variable interest in the entity and the entity is a VIE, it will also analyze whether the Partnership is the primary beneficiary of this entity and whether consolidation is required.

In evaluating whether it has a variable interest in the entity, the Partnership reviews the equity ownership and the extent to which it absorbs risk created and distributed by the entity, as well as whether the fees charged to the entity are customary and commensurate with the level of effort required to provide services. Fees received by the Partnership are not variable interests if (i) the fees are compensation for services provided and are commensurate with the level of effort required to provide those services, (ii) the service arrangement includes only terms, conditions, or amounts that are customarily present in arrangements for similar services negotiated at arm's length and (iii) the Partnership's other economic interests in the VIE held directly and indirectly through its related parties, as well as economic interests held by related parties under common control, where applicable, would not absorb more than an insignificant amount of the entity's losses or receive more than an insignificant amount of the entity's benefits. Evaluation of these criteria requires judgment.

For entities determined to be VIEs, the Partnership must then evaluate whether it is the primary beneficiary of such VIEs. To make this determination, the Partnership evaluates its economic interests in the entity specifically determining if the Partnership has both the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and the obligation to absorb losses or the right to receive benefits that could potentially be significant to the VIE (the "benefits"). When making the determination on whether the benefits received from an entity are significant, the Partnership considers the total economics of the entity, and analyzes whether the Partnership's share of the economics is significant. The Partnership utilizes qualitative factors, and, where applicable, quantitative factors, while performing the analysis.

VIEs of which the Partnership is the primary beneficiary have been included in the Partnership's consolidated financial statements. The portion of the consolidated subsidiaries owned by third parties and any related activity is eliminated through non-controlling interests in the consolidated balance sheets and income (loss) attributable to non-controlling interests in the consolidated statements of operations.

Investments Held in Trust by Consolidated Variable Interest Entities

Investments held in trust represent funds raised by TGR (as defined in Note 4), a consolidated special purpose acquisition company, through the TGR IPO (as defined in Note 4). These funds were held in an actively-traded money market fund, which invested in U.S. Treasury securities. Investments held in trust are classified as trading securities and are presented on the balance sheet at fair value at the end of each reporting period. Gains and losses resulting from the change in fair value of these securities are included in other income (expense)—interest earned on marketable securities in trust account on the accompanying unaudited interim consolidated statements of operations. The estimated fair values of investments held in the trust account are determined using quoted prices in an active market and therefore are classified in Level 1 of the fair value hierarchy, as described in Note 6— Fair Value Measurements.

Redeemable Non-Controlling Interest

Redeemable non-controlling interests represent the shares of Class A common stock of TGR, par value $ 0.0001 per share (the “Class A common stock”) sold in the TGR IPO that were redeemable for cash by the public TGR shareholders that would have been concurrent with TGR’s initial business combination or in the event of TGR’s failure to complete a business combination or a tender offer. The redeemable non-controlling interests were initially recorded at their original issue price, net of issuance costs and the initial fair value of separately traded warrants. As of June 30, 2023, the shares had been redeemed in full.

New Accounting Pronouncements

In March 2023, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) 2023-01, “Leases (Topic 842): Common Control Arrangements.” This update requires that (i) entities determine whether a related party arrangement between entities under common control is a lease and (ii) that leasehold improvements have an amortization period consistent with the shorter of the remaining lease term and the useful life of the improvements, which is an approach that is largely consistent with legacy guidance. This update is effective for financial statements issued for fiscal years beginning after December 15, 2023, including interim periods within that fiscal year. The Partnership is currently evaluating the impact of the adoption of this update, but does not believe it will have a material impact on its financial position, results of operations or liquidity.

NOTE 3—REVENUE FROM CONTRACTS WITH CUSTOMERS

The Partnership has the right to receive revenues from oil, natural gas and NGL sales obtained by the operator of the wells in which the Partnership owns a mineral or royalty interest. Revenue is recognized at the point control of the product is transferred to the purchaser. Virtually all of the pricing provisions in the Partnership’s contracts are tied to a market index.

The Partnership’s oil, natural gas and NGL sales contracts are generally structured whereby the producer of the properties in which the Partnership owns a mineral or royalty interest sells the Partnership’s proportionate share of oil, natural gas and NGL production to the purchaser and the Partnership collects its percentage royalty based on the revenue generated by the sale of the oil, natural gas and NGL. In this scenario, the Partnership recognizes revenue when control transfers to the purchaser at the wellhead or at the gas processing facility based on the Partnership’s percentage ownership share of the revenue, net of any deductions for gathering and transportation.

The following table disaggregates the Partnership’s oil, natural gas, and NGL revenues for the following periods:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
Oil revenue	$ 50,777,614	$ 32,044,316	$ 123,587,783	$ 100,384,497
Natural gas revenue	12,339,244	35,517,230	43,528,008	94,412,132
NGL revenue	6,120,745	6,306,446	16,520,185	22,746,735
Total Oil, natural gas and NGL revenues	$ 69,237,603	$ 73,867,992	$ 183,635,976	$ 217,543,364

NOTE 4—ACQUISITIONS, JOINT VENTURE AND SPECIAL PURPOSE ACQUISITION COMPANY

Acquisitions

On September 13, 2023, the Partnership completed the acquisition of all issued and outstanding membership interests of Cherry Creek Minerals LLC pursuant to a securities purchase agreement with LongPoint Minerals II, LLC (the “LongPoint Acquisition”) in a cash transaction valued at approximately $455.0 million. The Partnership funded the cash transaction with borrowings under its secured revolving credit facility and net proceeds from the Preferred Unit Transaction (as defined in Note 10—Preferred Units). The adjusted purchase price of the LongPoint Acquisition includes the total cash consideration of $455.0 million, transactional costs of $7.4 million and less $16.6 million of post-effective net oil, natural gas and NGL revenues earned prior to the closing date. The LongPoint Acquisition was accounted for as an asset acquisition and the allocation of the purchase price was $198.2 million to proved properties and $ 247.6 million to unevaluated properties.

On May 17, 2023, the Partnership completed the acquisition of certain mineral and royalty assets held by MB Minerals, L.P. and certain of its affiliates (the “MB Minerals Acquisition”). The aggregate consideration for the MB Minerals Acquisition consisted of (i) approximately $48.8 million in cash and (ii) the issuance of (a) 5,369,218 OpCo Common Units and an equal number of Class B units representing limited partnership interests in the Partnership (“Class B Units”) and (b) 557,302 common units. The Partnership funded the cash payment of the purchase price with borrowings under its secured revolving credit facility. The assets acquired in the MB Minerals Acquisition are located in Howard and Borden Counties, Texas. The MB Minerals Acquisition was accounted for as an asset acquisition and the allocation of the purchase price was $60.8 million to proved properties and $ 74.9 million to unevaluated properties.

On December 15, 2022, the Partnership completed the acquisition of certain mineral and royalty assets held by Hatch Royalty LLC (the “Hatch Acquisition”). The aggregate consideration for the Hatch Acquisition consisted of (i) approximately $150.4 million in cash and (ii) the issuance of 7,272,821 OpCo common units and an equal number of Class B units. The Partnership funded the cash payment of the purchase price with borrowings under its secured revolving credit facility. The assets acquired in the Hatch Acquisition are located in the Permian Basin and the Partnership estimates that the assets consisted of approximately 889 net royalty acres on approximately 230,000 gross acres. The Hatch Acquisition was accounted for as an asset acquisition and the allocation of the purchase price was $56.4 million to proved properties and $204.7 million to unevaluated properties.

Joint Venture

On June 19, 2019, the Partnership entered into a joint venture (the “Joint Venture”) with Springbok SKR Capital Company, LLC and Rivercrest Capital Partners, LP, a related party. The Partnership’s ownership in the Joint Venture was 49.3%. During the year ended December 31, 2022, the Joint Venture completed the sale of its royalty, mineral and overriding interests and similar non-cost bearing interests in oil and gas properties for a total purchase price of $15.0 million. Net proceeds distributed to the Partnership were $6.5 million during the year ended December 31, 2022, the majority of which was used to repay debt on the Partnership’s secured revolving credit facility. The Joint Venture was dissolved on November 1, 2022.

Special Purpose Acquisition Company

On February 8, 2022, the Partnership announced the $230 million initial public offering of its special purpose acquisition company, Kimbell Tiger Acquisition Corporation (NYSE: TGR).

Kimbell Tiger Acquisition Corporation ("TGR") was formed for the purpose of effecting a merger, capital stock exchange, asset acquisition, stock purchase, reorganization or similar business combination with one or more businesses. Kimbell Tiger Acquisition Sponsor, LLC ("TGR Sponsor"), which was a subsidiary of the Partnership, and was created to assist TGR in sourcing, analyzing and consummating acquisition opportunities for that initial business combination. TGR Sponsor and TGR were consolidated in the financial statements of the Partnership beginning in the year ended December 31, 2021.

On July 29, 2021, TGR, the Partnership's recently dissolved special purpose acquisition company and subsidiary, consummated its initial public offering (the "TGR IPO"). Under the terms of TGR's governing documents, TGR had until May 8, 2023 to complete a business combination, subject to TGR Sponsor's option to extend such deadline by three months up to two times.

On May 22, 2023, as a result of TGR's inability to consummate an initial business combination on or prior to May 8, 2023, and pursuant to the terms of its organizational documents, TGR redeemed all of its outstanding shares of Class A common stock included as part of the units issued in its initial public offering. The Class A common stock was redeemed on June 22, 2023 and the Partnership completed the dissolution and deconsolidation of TGR (along with TGR Sponsor) on June 30, 2023 in accordance with the terms of its organizational documents. The net non-cash impact of the deconsolidation of TGR was $1.6 million, which is included in the accompanying unaudited interim consolidated balance sheet as of September 30, 2023.

NOTE 5—DERIVATIVES

Commodity Derivatives

The Partnership's ongoing operations expose it to changes in the market price for oil and natural gas. To mitigate the inherent commodity price risk associated with its operations, the Partnership uses oil and natural gas commodity derivative financial instruments. From time to time, such instruments may include variable-to-fixed-price swaps, costless collars, fixed-price contracts and other contractual arrangements. The Partnership enters into oil and natural gas derivative contracts that contain netting arrangements with each counterparty.

As of September 30, 2023, the Partnership's commodity derivative contracts consisted of fixed price swaps, under which the Partnership receives a fixed price for the contract and pays a floating market price to the counterparty over a specified period for a contracted volume.

The Partnership's oil fixed price swap transactions are settled based upon the average daily prices for the calendar month of the contract period, and its natural gas fixed price swap transactions are settled based upon the last scheduled trading day for the first nearby month futures contract corresponding to the relevant contract period. Settlement for oil derivative contracts occurs in the succeeding month and natural gas derivative contracts are settled in the production month. Changes in the fair values of the Partnership's commodity derivative instruments are recognized as gains or losses in the current period and are presented on a net basis within revenue in the accompanying unaudited interim consolidated statements of operations.

Interest Rate Swaps

On January 27, 2021, the Partnership entered into an interest rate swap with Citibank, N.A., New York ("Citibank"), which fixed the interest rate on $150.0 million of the notional balance on our secured revolving credit facility. On May 17, 2022, the Partnership entered into a partial termination agreement with Citibank to unwind 50% of the interest rate swap. On August 8, 2022, the Partnership entered into a termination agreement with Citibank to unwind the remaining 50% of the interest rate swap. The terminations resulted in a $ 3.4 million gain and $6.4 million gain, which is included in other income (expense) in the accompanying unaudited interim consolidated statements of operations for the three and nine months ended September 30, 2022. The Partnership used an interest rate swap for the management of interest rate risk exposure, as the interest rate swap effectively converted a portion of the Partnership's secured revolving credit facility from a floating to a fixed rate. Changes in the fair values of the Partnership's interest rate swaps were recognized as gains or losses in the current period and were presented on a net basis within other income in the accompanying unaudited interim consolidated statements of operations.

The Partnership has not designated any of its derivative contracts as hedges for accounting purposes. Changes in the fair value consisted of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
Beginning fair value of derivative instruments	$ 2,776,238	$ (38,741,643)	$ (12,324,076)	$ (26,624,646)
(Loss) gain on commodity derivative instruments, net	(4,576,570)	(1,022,399)	6,215,265	(35,456,734)
Net cash paid on settlements of derivative instruments	479,005	14,410,499	4,787,484	36,727,837
Ending fair value of derivative instruments	$ (1,321,327)	$ (25,353,543)	$ (1,321,327)	$ (25,353,543)

The following table presents the fair value of the Partnership's derivative contracts for the periods indicated:

Classification	Balance Sheet Location	September 30, 2023	December 31, 2022
Assets:			
Current assets	Derivative assets	$ 1,489,189	$ —
Long-term assets	Derivative assets	134,841	754,786
Liabilities:			
Current liabilities	Derivative liabilities	(1,418,027)	(12,646,720)
Long-term liabilities	Derivative liabilities	(1,527,330)	(432,142)
		$ (1,321,327)	$ (12,324,076)

As of September 30, 2023, the Partnership's open commodity derivative contracts consisted of the following:

Oil Price Swaps

	Notional Volumes (Bbl)	Weighted Average Fixed Price (per Bbl)	Range (per Bbl) Low	Range (per Bbl) High
October 2023 - December 2023	146,464	$ 76.42	$ 63.00	$ 88.05
January 2024 - December 2024	568,926	$ 79.04	$ 69.30	$ 85.34
January 2025 - September 2025	417,154	$ 71.10	$ 64.35	$ 77.01

Natural Gas Price Swaps

	Notional Volumes (MMBtu)	Weighted Average Fixed Price (per MMBtu)	Range (per MMBtu) Low	Range (per MMBtu) High
October 2023 - December 2023	1,317,624	$ 3.22	$ 3.03	$ 3.28
January 2024 - December 2024	5,285,182	$ 3.97	$ 3.06	$ 4.48
January 2025 - September 2025	3,861,611	$ 3.86	$ 3.50	$ 4.37

NOTE 6—FAIR VALUE MEASUREMENTS

The Partnership measures and reports certain assets and liabilities on a fair value basis and has classified and disclosed its fair value measurements using the levels of the fair value hierarchy noted below. The carrying values of cash, oil, natural gas and NGL receivables, accounts receivable and other current assets and current and long-term liabilities included in the unaudited interim consolidated balance sheets approximated fair value as of September 30, 2023 and December 31, 2022 due to their short-term duration and variable interest rates that approximate prevailing interest rates as of each reporting period. As a result, these financial assets and liabilities are not discussed below.

- Level 1— Unadjusted quoted market prices for identical assets or liabilities in active markets.

- Level 2—Quoted prices for similar assets or liabilities in non-active markets, or inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the asset or liability.

- Level 3—Measurement based on prices or valuations models that require inputs that are both unobservable and significant to the fair value measurement (including the Partnership's own assumptions in determining fair value).

Assets and liabilities that are measured at fair value are classified based on the lowest level of input that is significant to the fair value measurement. The Partnership's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability. The Partnership recognizes transfers between fair value hierarchy levels as of the end of the reporting period in which the event or change in circumstances causing the transfer occurred. The Partnership did not have any transfers between Level 1, Level 2 or Level 3 fair value measurements during the three and nine months ended September 30, 2023 and 2022.

The estimated fair values of investments held in the trust account are determined using quoted prices in an active market and therefore are classified in Level 1 of the fair value hierarchy. The Partnership's commodity derivative instruments are classified within Level 2. The fair values of the Partnership's oil and natural gas fixed price swaps are based upon inputs that are either readily available in the public market, such as oil and natural gas futures prices, volatility factors and discount rates, or can be corroborated from active markets.

The following tables summarize the Partnership's assets and liabilities measured at fair value on a recurring basis by the fair value hierarchy:

	Fair Value Measurements Using				
	Level 1	Level 2	Level 3	Effect of Counterparty Netting	Total
September 30, 2023					
Assets					
Commodity derivative contracts	$ —	$ 1,624,030	$ —	$ —	$ 1,624,030
Liabilities					
Commodity derivative contracts	$ —	$ (2,945,357)	$ —	$ —	$ (2,945,357)
December 31, 2022					
Assets					
Commodity derivative contracts	$ —	$ 754,786	$ —	$ —	$ 754,786
Assets of consolidated variable interest entities:					
Investments held in trust	$ 240,621,146	$ —	$ —	$ —	$ 240,621,146
Liabilities					
Commodity derivative contracts	$ —	$ (13,078,862)	$ —	$ —	$ (13,078,862)

NOTE 7—OIL AND NATURAL GAS PROPERTIES

Oil and natural gas properties consist of the following:

	September 30, 2023	December 31, 2022
Oil and natural gas properties		
Proved properties	$ 1,709,319,998	$ 1,258,290,375
Unevaluated properties	338,840,127	207,695,343
Less: accumulated depreciation, depletion and impairment	(772,711,451)	(712,716,951)
Total oil and natural gas properties	$ 1,275,448,674	$ 753,268,767

The net capitalized costs of proved oil and natural gas properties are subject to a full-cost ceiling limitation for which the costs are not allowed to exceed their related estimated future net revenues discounted at 10%. To the extent capitalized costs of evaluated oil and natural gas properties, net of accumulated depreciation, depletion, amortization and impairment, exceed estimated discounted future net revenues of proved oil and natural gas reserves, the excess capitalized costs are charged to expense. The Partnership assesses all unevaluated properties on a periodic basis for possible impairment. The Partnership assesses properties on an individual basis or as a group if properties are individually insignificant. The assessment includes consideration of the following factors, among others: economic and market conditions, operators' intent to drill, remaining lease term, geological and geophysical evaluations, operators' drilling results and activity, the assignment of proved reserves and the economic viability of operator development if proved reserves are assigned. Costs associated with unevaluated properties are excluded from the full cost pool until a determination as to the existence of proved developed producing reserves is able to be made. During any period in which these factors indicate an impairment, all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization and to the full cost ceiling test. The Partnership did not record an impairment on its oil and natural gas properties for the three or nine months ended September 30, 2023 or 2022.

NOTE 8—LEASES

Substantially all of the Partnership's leases are long-term operating leases with fixed payment terms and will terminate in June 2029. The Partnership's right-of-use ("ROU") operating lease assets represent its right to use an underlying asset for the lease term, and its operating lease liabilities represent its obligation to make lease payments. ROU operating lease assets and operating lease liabilities are included in the accompanying unaudited interim consolidated balance sheets. Short term operating lease liabilities are included in other current liabilities. The weighted average remaining lease term as of September 30, 2023 is 5.64 years.

Both the ROU operating lease assets and liabilities are recognized at the present value of the remaining lease payments over the lease term and do not include lease incentives. The Partnership's leases do not provide an implicit rate that can readily be determined; therefore, the Partnership used a discount rate based on its incremental borrowing rate, which is determined by the information available in the secured revolving credit facility. The incremental borrowing rate reflects the estimated rate of interest that the Partnership would pay to borrow, on a collateralized basis over a similar term, an amount equal to the lease payments in a similar economic environment. The weighted average discount rate used for the operating leases was 6.75% for the nine months ended September 30, 2023.

Operating lease expense is recognized on a straight-line basis over the lease term and is included in general and administrative expense in the accompanying unaudited interim consolidated statements of operations for the three and nine months ended September 30, 2023 and 2022. The total operating lease expense recorded for both the three months ended September 30, 2023 and 2022 was $0.1 million and $0.4 million for both the nine months ended September 30, 2023 and 2022.

Currently, the most substantial contractual arrangements that the Partnership has classified as operating leases are the main office spaces used for operations.

Future minimum lease commitments as of September 30, 2023 were as follows:

	Total	2023	2024	2025	2026	2027	Thereafter
Operating leases	$ 2,834,748	$ 122,075	$ 488,725	$ 497,033	$ 507,648	$ 511,917	$ 707,350
Less: Imputed Interest	(514,749)						
Total	$ 2,319,999						

NOTE 9—LONG-TERM DEBT

On June 13, 2023, the Partnership entered into an Amended and Restated Credit Agreement (the "A&R Credit Agreement"), which amended and restated the Partnership's existing Credit Agreement, dated as of January 11, 2017 (as amended on July 12, 2018, December 8, 2020, June 7, 2022 and December 15, 2022). On July 24, 2023, the Partnership entered into Amendment No. 1 (the "First Amendment") to the A&R Credit Agreement. The amendment amended the A&R Credit Agreement to, among other things, (i) decrease the frequency of and increase the threshold for excess cash determinations from $30.0 million to $50.0 million, and (ii) permit the Partnership to issue certain preferred equity interests.

The A&R Credit Agreement provides for, among other things, (i) a senior secured reserve-based revolving credit facility in an aggregate maximum principal amount of up to $750.0 million with an initial borrowing base of $400.0 million and an initial aggregate elected commitments amount of up to $400.0 million, including a sub-facility for the issuance of letters of credit of up to $10.0 million, and (ii) an extension of the maturity date of the A&R Credit Agreement to June 7, 2027.

The revolving credit facility bears interest at a rate equal to, at the Partnership's election, either (a) the Secured Overnight Financing Rate (as defined in the A&R Credit Agreement) plus an applicable margin that varies from 2.75% to 3.75% per annum or (b) a base rate plus an applicable margin that varies from 1.75% to 2.75% per annum, based on borrowing base utilization.

The revolving credit facility is guaranteed by certain of the Partnership's material subsidiaries and is collateralized by substantially all assets, including the oil and natural gas properties of such subsidiaries, including mortgages on at least 75% of the PV-9 of the proved reserves constituting borrowing base properties as set forth on the Partnership's most recent reserve report. The borrowing base will be redetermined semi-annually on or about May 1 and November 1 of each year by the Lenders, with one interim unscheduled redetermination available to each of the Partnership and a group of certain Lenders between scheduled redeterminations during each calendar year. The first scheduled redetermination will be on or around November 1, 2023. The November borrowing base redetermination is currently being conducted and is expected to be finalized by the end of November 2023.

Customary borrowing base reductions and mandatory prepayments are required under the A&R Credit Agreement in connection with certain sales of certain types of borrowing base properties, sales of equity interests in guarantor subsidiaries owning such properties, certain debt issuances or certain types of swap terminations. In addition, Cash Balance (as defined in the First Amendment) above $50.0 million is required to be applied weekly to prepay loans (without a commitment reduction) if not otherwise reduced to zero in a manner permitted by the A&R Credit Agreement.

The Partnership is required to pay a commitment fee of 0.50% per annum on the average daily unused portion of the current aggregate commitments under the secured revolving credit facility. The Partnership is also required to pay customary letter of credit and fronting fees.

The A&R Credit Agreement requires the Partnership to maintain as of the last day of each fiscal quarter: (i) a Debt to EBITDAX Ratio (as defined in the A&R Credit Agreement) of not more than 3.5 to 1.0 and (ii) a ratio of current assets to current liabilities of not less than 1.0 to 1.0, each beginning with the fiscal quarter ending September 30, 2023.

The A&R Credit Agreement also contains customary affirmative and negative covenants, including, among other things, as to compliance with laws (including environmental laws and anti-corruption laws), delivery of quarterly and annual financial statements and borrowing base certificates, conduct of business, maintenance of property, maintenance of insurance, entry into certain derivatives contracts, restrictions on the incurrence of liens, indebtedness, asset dispositions, restricted payments, and other customary covenants. These covenants are subject to a number of limitations and exceptions.

Additionally, the A&R Credit Agreement contains customary events of default and remedies for credit facilities of this nature. If the Partnership does not comply with the financial and other covenants in the A&R Credit Agreement, the Lenders may, subject to customary cure rights, require immediate payment of all amounts outstanding under the A&R Credit Agreement and any outstanding unfunded commitments may be terminated.

In connection with the A&R Credit Agreement, the Partnership recorded a loss on extinguishment of debt of $0.5 million as a result of writing off all unamortized loan origination costs associated with the lenders to the Partnership's existing credit agreement that did not participate in the A&R Credit Agreement.

During the nine months ended September 30, 2023, the Partnership borrowed an additional $ 201.1 million under the secured revolving credit facility and repaid approximately $123.7 million of the outstanding borrowings. As of September 30, 2023, the Partnership's outstanding balance was $310.4 million. The Partnership was in compliance with all covenants included in the secured revolving credit facility as of September 30, 2023.

As of September 30, 2023, borrowings under the secured revolving credit facility bore interest at SOFR plus a margin of 3.50% or the ABR (as defined in the Amended Credit Agreement) plus a margin of 2.50%. For the three and nine months ended September 30, 2023, the weighted average interest rate on the Partnership's outstanding borrowings was 8.64% and 8.56%, respectively.

NOTE 10—PREFERRED UNITS

On August 2, 2023, the Partnership entered into a Series A preferred unit purchase agreement with certain funds managed by affiliates of Apollo (NYSE: APO) (collectively, the "Series A Purchasers") to issue and sell up to 400,000 Series A Cumulative Convertible Preferred Units representing limited partner interests in the Partnership (the "Series A preferred units"). On September 13, 2023, in connection with the closing of the LongPoint Acquisition, the Partnership completed the private placement of 325,000 Series A preferred units to the Series A Purchasers for $ 1,000 per Series A preferred unit, resulting in gross proceeds to the Partnership of $325.0 million (the "Preferred Unit Transaction"). The Partnership used the net proceeds from the Preferred Unit Transaction to purchase 325,000 preferred units of the Operating Company ("OpCo preferred units"). The Operating Company in turn used the net proceeds to fund a portion of the LongPoint Acquisition. The Series A preferred units rank senior to the Partnership's common units with respect to distribution rights and rights upon liquidation.

Until the conversion of the Series A preferred units into common units or their redemption, holders of the Series A preferred units are entitled to receive cumulative quarterly distributions equal to 6.0% per annum plus accrued and unpaid distributions. The Partnership has the right, in any four non-consecutive quarters, to elect not to pay such quarterly distribution in cash and instead have the unpaid distribution amount added to the liquidation preference at the rate of 10.0% per annum. If the Partnership makes such an election in consecutive quarters or if the Partnership fails to pay in full, in cash and when due, any distribution owed to the Series A preferred units or otherwise materially breaches its obligations to the holders of the Series A preferred units, the distribution rate will increase to 20.0% per annum until the accumulated distributions are paid in full in cash, or any such material breach is cured, as applicable. Each holder of Series A preferred units has the right to share in any special distributions by the Partnership of cash, securities or other property pro rata with the common units on an as-converted basis, subject to customary adjustments. The Partnership cannot declare or make any distributions, redemptions, or repurchases on any junior securities, including any of their common units, prior to paying the quarterly distribution payable to the Series A preferred units, including any previously accrued and unpaid distributions.

Beginning with the earlier of (i) the second anniversary of the original issuance date and (ii) immediately prior to a liquidation of the Partnership, the Series A Purchasers may, at any time (but not more often than once per quarter), elect to convert all or any portion of their Series A preferred units into a number of common units determined by multiplying the number of Series A preferred units to be converted by the then-applicable conversion rate, provided that (a) any conversion is for an amount of common units with an aggregate value of at least $10.0 million or such lesser amount that covers all of the holders' remaining Series A preferred units and (b) the closing price of the common units is at least 130% of the conversion price of $15.07, subject to certain anti-dilution adjustments (the "Conversion Price") for 20 trading days during the 30-trading day period immediately preceding the conversion notice.

At any time on or after the second anniversary of the original issuance date, the Partnership will have the option to convert all or any portion of the Series A preferred units into a number of common units determined by the then-applicable conversion rate, provided that (i) any conversion is for an amount of common units with an aggregate value of at least $10.0 million or such lesser amount that covers all of the holders' Series A preferred units, (ii) the common units are listed for, or admitted to, trading on a national securities exchange, (iii) the closing price of the common units is at least 160% of the Conversion Price for 20 trading days during the 30-trading day period immediately preceding the conversion notice and (iv) the Partnership has an effective registration statement on file with the SEC covering resales of the underlying common units to be received by the holders of Series A preferred units upon such conversion.

The Series A preferred units are redeemable at the option of the Series A Purchasers after seven years. The Series A preferred units may be redeemed by the Partnership at any time or in the event of a change of control. The Series A preferred units may be redeemed for a cash amount per Series A preferred unit equal to the product of (a) the number of outstanding Series A preferred units multiplied by (b) the greatest of (i) an amount (together with all prior distributions made in respect of such Series A preferred unit) necessary to achieve the Minimum IRR (as defined below), (ii) an amount (together with all prior distributions made in respect of such Series A preferred unit) necessary to achieve a return on investment equal to 1.2 times with respect to such Series A p referred unit and (iii) the Series A issue price plus accrued and unpaid distributions.

For purposes of the Series A preferred units, "Minimum IRR" means as of any measurement date: (a) prior to the fifth anniversary of the original issuance date, a 12.0% internal rate of return with respect to the Series A preferred units; (b) on or after the fifth anniversary of the original issuance date and prior to the sixth anniversary of the original issuance date, a 13.0% internal rate of return with respect to the Series A preferred units; and (c) on or after the sixth anniversary of the original issuance date, a 14.0% internal rate of return with respect to the Series A preferred units.

In connection with the issuance of the Series A preferred units, the Partnership granted holders of the Series A preferred units board observer rights beginning on the fifth anniversary of the original issuance date, board appointment rights beginning on the sixth anniversary of the original issuance date, and in the case of events of default with respect to the Series A preferred units, the right to appoint two members of the board beginning on the seventh anniversary of the original issuance date.

The terms of the Series A preferred units contain covenants preventing the Partnership from taking certain actions without the approval of the holders of $66^2/_3$% of the outstanding Series A preferred units, voting separately as a class.

NOTE 11—UNITHOLDERS' EQUITY AND PARTNERSHIP DISTRIBUTIONS

The Partnership has issued units representing limited partner interests. As of September 30, 2023, the Partnership had a total of 73,851,458 common units issued and outstanding and 20,847,295 Class B units outstanding.

In November 2022, the Partnership completed an underwritten public offering of 6,900,000 common units for net proceeds of approximately $116.1 million (the "2022 Equity Offering"). The Partnership used the net proceeds from the 2022 Equity Offering to purchase OpCo common units. Kimbell Royalty Operating, LLC (the "Operating Company") in turn used the net proceeds to repay approximately $116.0 million of the outstanding borrowings under the Partnership's secured revolving credit facility.

On August 7, 2023, the Partnership completed an underwritten public offering of 8,337,500 common units for net proceeds of approximately $110.7 million (the "2023 Equity Offering"). The Partnership used the net proceeds from the 2023 Equity Offering to purchase OpCo common units. The Operating Company in turn used the net proceeds to repay approximately $90.0 million of the outstanding borrowings under the Partnership's secured revolving credit facility. The Operating Company used the remainder of the net proceeds of the 2023 Equity Offering for general corporate purposes.

The following table summarizes the changes in the number of the Partnership's common units:

	Common Units
Balance at December 31, 2022	64,231,833
Common units issued under the A&R LTIP (1)	998,162
Restricted units repurchased for tax withholding	(279,662)
Common unit issued for acquisition	557,302
Common units issued for equity offering	8,337,500
Conversion of Class B units	6,323
Balance at September 30, 2023	73,851,458

(1) Includes restricted units granted to certain employees and directors under the Amended and Restated Kimbell Royalty GP, LLC 2017 Long-Term Incentive Plan on February 21, 2023.

The following table presents information regarding the common unit cash distributions approved by the General Partner's Board of Directors (the "Board of Directors") for the periods presented:

	Amount per Common Unit	Date Declared	Unitholder Record Date	Payment Date
Q1 2023	$ 0.35	May 3, 2023	May 15, 2023	May 22, 2023
Q2 2023	$ 0.39	August 2, 2023	August 14, 2023	August 21, 2023
Q3 2023	$ 0.51	November 2, 2023	November 13, 2023	November 20, 2023
Q1 2022	$ 0.47	April 22, 2022	May 2, 2022	May 9, 2022
Q2 2022	$ 0.55	August 3, 2022	August 15, 2022	August 22, 2022
Q3 2022	$ 0.49	November 3, 2022	November 14, 2022	November 21, 2022

For each Class B unit issued, five cents has been paid to the Partnership as additional consideration (the "Class B Contribution"). Holders of the Class B units are entitled to receive cash distributions equal to 2.0% per quarter on their respective Class B Contribution prior to distributions on the common units and OpCo common units.

The Class B units and OpCo common units are exchangeable together into an equal number of common units of the Partnership.

NOTE 12—EARNINGS PER COMMON UNIT

Basic earnings per common unit is calculated by dividing net income attributable to common units by the weighted-average number of common units outstanding during the period. Diluted net income per common unit gives effect, when applicable, to unvested restricted units granted under the Partnership's A&R LTIP (as defined in Note 12) for its employees, directors and consultants and potential conversion of Series A preferred units and Class B units. The Partnership uses the "if-converted" method to determine the potential dilutive effect of exchanges of outstanding Series A preferred units and Class B units (and corresponding units of Kimbell Royalty Partners, LP), and the treasury stock method to determine the potential dilutive effect of vesting of outstanding restricted units granted under the Partnership's LTIP. The Partnership does not use the two-class method because the Class B units and the unvested restricted units granted under the Partnership's A&R LTIP are nonparticipating securities.

The following table summarizes the calculation of weighted average common units outstanding used in the computation of diluted earnings per common unit:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
Net income attributable to common units of Kimbell Royalty Partners, LP	$ 13,580,211	$ 38,343,786	$ 50,368,835	$ 83,536,606
Net adjustment to accretion of redeemable non-controlling interest in Kimbell Tiger Acquisition Corporation and write-off of deferred underwriting commissions	—	—	1,572,737	(17,845,231)
Net income attributable to common units of Kimbell Royalty Partners, LP after accretion of redeemable non-controlling interest in Kimbell Tiger Acquisition Corporation and write-off of deferred underwriting commissions	13,580,211	38,343,786	51,941,572	65,691,375
Distribution and accretion on Series A preferred units	1,040,572	—	1,040,572	—
Net income attributable to non-controlling interests in OpCo and distribution on Class B units	3,860,255	—	13,768,200	—
Diluted net income attributable to common units of Kimbell Royalty Partners, LP	$ 18,481,038	$ 38,343,786	$ 66,750,344	$ 65,691,375
Weighted average number of common units outstanding:				
Basic	68,540,786	55,434,641	64,807,590	52,302,235
Effect of dilutive securities:				
Series A preferred units	4,219,440	—	1,421,936	—
Class B units	20,853,412	8,211,579	18,178,773	11,245,161
Restricted units	1,355,439	1,897,192	1,331,514	1,850,067
Diluted	94,969,077	65,543,412	85,739,813	65,397,463
Net income per unit attributable to common units of Kimbell Royalty Partners, LP				
Basic	$ 0.20	$ 0.69	$ 0.80	$ 1.26
Diluted	$ 0.19	$ 0.59	$ 0.78	$ 1.00

The calculation of diluted net income per share for the three and nine months ended September 30, 2023 includes the conversion of Series A preferred units to common units and Class B units to common units calculated using the "if-converted" method and units of unvested restricted units calculated using the treasury stock method. The calculation of diluted net income per share for the three and nine months ended September 30, 2022 includes the conversion of all Class B units to common units calculated using the "if-converted" method and units of unvested restricted units calculated using the treasury stock method.

NOTE 13—UNIT-BASED COMPENSATION

On May 18, 2022, the Partnership held a special meeting of unitholders of the Partnership (the "Special Meeting"), at which the Partnership's unitholders voted to approve the Amended and Restated Kimbell Royalty GP, LLC 2017 Long-Term Incentive Plan (the "A&R LTIP"), which increased the number of common units eligible for issuance under the A&R LTIP by 3,700,000 common units for a total of 8,241,600 common units. The Partnership's A&R LTIP authorizes grants to its employees, directors and consultants. The restricted units issued under the Partnership's A&R LTIP generally vest in one-third installments on each of the first three anniversaries of the grant date, subject to the grantee's continuous service through the applicable vesting date. Compensation expense for such awards will be recognized over the term of the service period on a straight-line basis over the requisite service period for the entire award. Management elects not to estimate forfeiture rates and to account for forfeitures in compensation cost when they occur. Compensation expense for consultants is treated in the same manner as that of the employees and directors.

Distributions related to the restricted units are paid concurrently with the Partnership's distributions for common units. The fair value of the Partnership's restricted units issued under the A&R LTIP to the Partnership's employees, directors and consultants is determined by utilizing the market value of the Partnership's common units on the respective grant date. The following table presents a summary of the Partnership's unvested restricted units.

	Units	Weighted Average Grant-Date Fair Value per Unit	Weighted Average Remaining Contractual Term
Unvested at December 31, 2022	1,897,192	$ 13.553	1.517 years
Awarded	998,162	15.020	—
Vested	(943,924)	12.602	—
Unvested at September 30, 2023	1,951,430	$ 14.763	1.777 years

NOTE 14—INCOME TAXES

The Partnership's provision for income taxes is based on the estimated annual effective tax rate plus discrete items. The Partnership recorded an income tax expense of $0.1 million and an income tax benefit of $ 0.2 million for the three months ended September 30, 2023 and 2022, respectively, and an income tax expense of $2.4 million and $1.9 million for the nine months ended September 30, 2023 and 2022, respectively.

NOTE 15—RELATED PARTY TRANSACTIONS

The Partnership currently has a management services agreement with Kimbell Operating, which has separate services agreements with each of BJF Royalties, LLC ("BJF Royalties") and K3 Royalties, LLC ("K3 Royalties"), pursuant to which they and Kimbell Operating provide management, administrative and operational services to the Partnership. In addition, under each of their respective services agreements, affiliates of the Partnership's Sponsors may identify, evaluate and recommend to the Partnership acquisition opportunities and negotiate the terms of such acquisitions. Amounts paid to Kimbell Operating and such other entities under their respective services agreements will reduce the amount of cash available for distribution on common units to the Partnership's unitholders.

During the three and nine months ended September 30, 2023, no monthly services fee was paid to BJF Royalties. During the three and nine months ended September 30, 2023, the Partnership made payments to K3 Royalties in the amount of $30,000 and $90,000, respectively. Certain consultants who provide services under management services agreements are granted restricted units under the Partnership's A&R LTIP.

The Partnership received $48,038 and $153,133 in reimbursements from Rivercrest Capital Management, LLC for shared operating expenses for the three and nine months ended September 30, 2023, respectively.

Commencing on the date of the TGR IPO, TGR agreed to pay the Partnership a total of $ 25,000 per month for office space utilities, secretarial support and administrative services provided to members of the management team. During the nine months ended September 30, 2023, TGR incurred $50,000 as part of this service agreement. Such fees were eliminated in consolidation. Upon TGR's liquidation, TGR ceased paying these monthly fees.

NOTE 16—ADMINISTRATIVE SERVICES

Transition Services Agreement

On September 13, 2023, in connection with the LongPoint Acquisition and pursuant to the terms of the securities purchase agreement, a transition services agreement (the "Transition Services Agreement") by and between the Operating Company and FourPoint Energy, LLC ("FourPoint"), the former manager of the acquired assets, became effective. Pursuant to the Transition Services Agreement, FourPoint will provide certain administrative services and accounting assistance on a transitional basis for a monthly service fee of approximately $250,000 for the four-month period ending January 13, 2024, at which point the Transition Services Agreement will automatically renew on a month-to-month basis through January 13, 2025, unless earlier terminated by the Partnership.

NOTE 17—COMMITMENTS AND CONTINGENCIES

During the normal course of business, the Partnership may experience situations where disagreements occur relating to the ownership of certain mineral or overriding royalty interest acreage. Management is not aware of any legal, environmental or other commitments or contingencies that would have a material effect on the Partnership's financial condition, results of operations or liquidity as of September 30, 2023.

NOTE 18—SUBSEQUENT EVENTS

The Partnership has evaluated events that occurred subsequent to September 30, 2023 in the preparation of its unaudited interim consolidated financial statements.

Distributions

On November 2, 2023, the Board of Directors declared a quarterly cash distribution of $ 0.51 per common unit and OpCo common unit for the quarter ended September 30, 2023. The Partnership intends to pay this distribution on November 20, 2023 to common unitholders and OpCo common unitholders of record as of the close of business on November 13, 2023.

The Partnership will pay a pro-rated quarterly cash distribution on the Series A preferred units of approximately $1.0 million for the quarter ended September 30, 2023. The Partnership intends to pay the distribution subsequent to November 13, 2023 and prior to the distribution on the common units and OpCo common units.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of financial condition and results of operations should be read in conjunction with our unaudited interim consolidated financial statements and notes thereto presented in this Quarterly Report on Form 10-Q (this "Quarterly Report"), as well as our audited financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2022 (the "2022 Form 10-K").

Unless the context otherwise requires, references to "Kimbell Royalty Partners, LP," the "Partnership," "we" or "us" refer to Kimbell Royalty Partners, LP and its subsidiaries. References to the "Operating Company" or "OpCo" refer to Kimbell Royalty Operating, LLC. References to the "General Partner" refer to Kimbell Royalty GP, LLC. References to the "Sponsors" refer to affiliates of the Partnership's founders, Ben J. Fortson, Robert D. Ravnaas, Brett G. Taylor and Mitch S. Wynne, respectively. References to the "Contributing Parties" refer to all entities and individuals, including certain affiliates of the Sponsors, that contributed, directly or indirectly, certain mineral and royalty interests to the Partnership.

Cautionary Statement Regarding Forward-Looking Statements

Certain statements and information in this Quarterly Report may constitute forward-looking statements. Forward-looking statements give our current expectations, contain projections of results of operations or of financial condition, or forecasts of future events. Words such as "may," "assume," "forecast," "position," "predict," "strategy," "expect," "intend," "plan," "estimate," "anticipate," "believe," "project," "budget," "potential," or "continue," and similar expressions are used to identify forward-looking statements. They can be affected by assumptions used or by known or unknown risks or uncertainties. Consequently, no forward-looking statements can be guaranteed. When considering these forward-looking statements, you should keep in mind the risk factors and other cautionary statements in this Quarterly Report. Actual results may vary materially. You are cautioned not to place undue reliance on any forward-looking statements. You should also understand that it is not possible to predict or identify all such factors and should not consider the following list to be a complete statement of all potential risks and uncertainties. All comments concerning our expectations for future revenues and operating results are based on our forecasts for our existing operations and do not include the potential impact of future operations or acquisitions. Factors that could cause our actual results to differ materially from the results contemplated by such forward-looking statements include:

- our ability to replace our reserves;
- our ability to make, consummate and integrate acquisitions of assets or businesses and realize the benefits or effects of any acquisitions or the timing, final purchase price or consummation of any acquisitions;
- our ability to execute our business strategies;
- the volatility of realized prices for oil, natural gas and natural gas liquids ("NGLs"), including as a result of actions by, or disputes among or between, members of the Organization of Petroleum Exporting Countries ("OPEC") and other foreign, oil-exporting countries;
- the level of production on our properties;
- the level of drilling and completion activity by the operators of our properties;
- our ability to forecast identified drilling locations, gross horizontal wells, drilling inventory and estimates of reserves on our properties and on properties we seek to acquire;
- regional supply and demand factors, delays or interruptions of production;
- industry, economic, business or political conditions, including the energy and environmental proposals being considered and evaluated by the federal government and other regulating bodies;
- the continued threat of terrorism and the impact of military and other action and armed conflict, such as the current conflict between Russia and Ukraine and the conflict in the Middle East;
- revisions to our reserve estimates as a result of changes in commodity prices, decline curves and other uncertainties;

- impact of impairment expense on our financial statements;
- competition in the oil and natural gas industry generally and the mineral and royalty industry in particular;
- the ability of the operators of our properties to obtain capital or financing needed for development and exploration operations;
- title defects in the properties in which we acquire an interest;
- the availability or cost of rigs, completion crews, equipment, raw materials, supplies, oilfield services or personnel to the operators of our properties;
- restrictions on or the availability of the use of water in the business of the operators of our properties;
- the availability of transportation facilities;
- the ability of the operators of our properties to comply with applicable governmental laws and regulations and to obtain permits and governmental approvals;
- federal and state legislative and regulatory initiatives relating to the environment, hydraulic fracturing, tax laws and other matters affecting the oil and gas industry, including the Biden administration's proposals and recent executive orders focused on addressing climate change;
- future operating results;
- exploration and development drilling prospects, inventories, projects and programs;
- operating hazards faced by the operators of our properties;
- the ability of the operators of our properties to keep pace with technological advancements;
- uncertainties regarding United States federal income tax law, including the treatment of our future earnings and distributions; and
- our ability to maintain effective internal controls over financial reporting and disclosure controls and procedures.

These factors are discussed in further detail in the 2022 Form 10-K under "Item 1A. Risk Factors" in Part I and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" in Part II and elsewhere in this Quarterly Report. Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. We undertake no obligation to publicly update or revise any forward-looking statements after the date they are made, whether as a result of new information, future events or otherwise. All forward-looking statements are expressly qualified in their entirety by the foregoing cautionary statements.

Overview

We are a Delaware limited partnership formed in 2015 to own and acquire mineral and royalty interests in oil and natural gas properties throughout the United States. We have elected to be taxed as a corporation for United States federal income tax purposes. As an owner of mineral and royalty interests, we are entitled to a portion of the revenues received from the production of oil, natural gas and associated NGLs from the acreage underlying our interests, net of post-production expenses and taxes. We are not obligated to fund drilling and completion costs, lease operating expenses or plugging and abandonment costs at the end of a well's productive life. Our primary business objective is to provide increasing cash distributions to unitholders resulting from acquisitions from third parties, our Sponsors and the Contributing Parties and from organic growth through the continued development by working interest owners of the properties in which we own an interest.

As of September 30, 2023, we owned mineral and royalty interests in approximately 12.2 million gross acres and overriding royalty interests in approximately 4.7 million gross acres, with approximately 55% of our aggregate acres located in the Permian Basin and Mid-Continent. We refer to these non-cost-bearing interests collectively as our "mineral and royalty interests." As of September 30, 2023, over 99% of the acreage subject to our mineral and royalty interests was leased to working interest owners, including 100% of our overriding royalty interests, and substantially all of those leases were held by production. Our mineral and royalty interests are located in 28 states and in every major onshore basin across the continental United States and include ownership in over 127,000 gross wells, including over 49,000 wells in the Permian Basin.

The following table summarizes our ownership in United States basins and producing regions and information about the wells in which we have a mineral or royalty interest as September 30, 2023:

Basin or Producing Region	Gross Acreage	Net Acreage	Average Daily Production (Boe/d)(6:1)(1)	Well Count
Permian Basin	3,336,728	26,930	7,493	49,735
Mid-Continent	5,868,927	48,833	1,887	20,752
Terryville/Cotton Valley/Haynesville	1,428,907	7,919	3,850	16,175
Appalachian Basin	741,354	23,203	1,744	3,871
Bakken/Williston Basin	1,640,077	6,138	927	5,278
Eagle Ford	624,148	6,730	1,884	4,088
DJ Basin/Rockies/Niobrara	74,152	1,036	775	12,540
Other	3,232,561	36,692	1,217	15,413
Total	16,946,854	157,481	19,777	127,852

(1) “Btu-equivalent” production volumes are presented on an oil-equivalent basis using a conversion factor of six Mcf of natural gas per barrel of “oil equivalent,” which is based on approximate energy equivalency and does not reflect the price or value relationship between oil and natural gas. Please read “Business—Oil and Natural Gas Data—Proved Reserves—Summary of Estimated Proved Reserves” in our 2022 Form 10-K.

The following table summarizes information about the number of drilled but uncompleted wells (“DUCs”) and permitted locations on acreage in which we have a mineral or royalty interest as of September 30, 2023:

Basin or Producing Region(1)	Gross DUCs	Gross Permits	Net DUCs	Net Permits
Permian Basin	551	469	3.06	2.38
Mid-Continent	177	66	0.96	0.32
Terryville/Cotton Valley/Haynesville	83	24	0.86	0.34
Appalachian Basin	5	9	0.01	0.02
Bakken/Williston Basin	64	155	0.17	0.14
Eagle Ford	26	63	0.33	0.56
DJ Basin/Rockies/Niobrara	3	19	0.01	0.18
Total	909	805	5.40	3.94

(1) The above table represents DUCs and permitted locations only, and there is no guarantee that the DUCs or permitted locations will be developed into producing wells in the future.

Kimbell Tiger Acquisition Corporation

In April 2021, we formed Kimbell Tiger Acquisition Corporation (“TGR”) as a special purpose acquisition company, or SPAC, for the purpose of effecting a merger, capital stock exchange, asset acquisition, stock purchase, reorganization or similar business combination with one or more businesses.

On February 8, 2022, TGR completed its initial public offering. Proceeds of $236.9 million were deposited in a trust account established for the benefit of TGR’s public unitholders consisting of certain proceeds from the TGR IPO and certain proceeds from the sale of the private placement warrants, net of underwriters’ discounts and commissions and other costs and expenses. The proceeds held in the trust account were not available to be used by us at any time. On May 22, 2023, as a result of TGR’s inability to consummate an initial business combination on or prior to May 8, 2023, and pursuant to the terms of its organizational documents, TGR redeemed all of its outstanding shares of Class A common stock included as part of the units issued in its initial public offering. The per-share redemption price for the TGR public shares was $10.57. The public shares of TGR ceased trading as of the close of business on May 8, 2023. As of the close of business on May 9, 2023, the public shares were deemed cancelled and represented only the right to receive the redemption amount. Following such redemption, TGR (along with TGR Sponsor) was dissolved in accordance with the terms of its organizational documents. There were no redemption rights or liquidating distributions with respect to TGR’s warrants, including the Private Placement Warrants held by TGR Sponsor, which expired worthless. TGR Sponsor waived its redemption rights with respect to TGR's outstanding common stock issued before TGR's initial public offering. The non-cash impact of the deconsolidation of TGR was $1.6 million, which is included in the accompanying unaudited interim consolidated balance sheet as of September 30, 2023.

Recent Developments

Acquisition

On May 17, 2023, we completed the acquisition of certain mineral and royalty assets held by MB Minerals, L.P. and certain of its affiliates (the "MB Minerals Acquisition"). The aggregate consideration for the MB Minerals Acquisition consisted of (i) approximately $48.8 million in cash and (ii) the issuance of (a) 5,369,218 common units of the Operating Company ("OpCo common units") and an equal number of Class B units representing limited partnership interests in the Partnership ("Class B Units") and (b) 557,302 common unit representing limited partner interests in the Partnership ("common units"). We funded the cash payment of the purchase price with borrowings under our secured revolving credit facility. The assets acquired in the MB Minerals Acquisition are located in Howard and Borden Counties, Texas.

On September 13, 2023, we completed the acquisition of all of the issued and outstanding membership interests of Cherry Creek Minerals LLC pursuant to a securities purchase agreement with LongPoint Minerals II, LLC (the "LongPoint Acquisition") in a cash transaction valued at approximately $455.0 million. We funded the cash transaction with borrowings under our secured revolving credit facility and net proceeds from the Preferred Unit Transaction (as defined in Note 10—Preferred Units).

Series A Preferred Units

On August 2, 2023, we entered into a Series A preferred unit purchase agreement with certain funds managed by affiliates of Apollo (NYSE: APO) (collectively, the "Series A Purchasers") to issue and sell up to 400,000 Series A Cumulative Convertible Preferred Units representing limited partner interests in the Partnership (the "Series A preferred units"). On September 13, 2023, in connection with the closing of the LongPoint Acquisition, we completed the private placement of 325,000 Series A preferred units to the Series A Purchasers for $1,000 per Series A preferred unit, resulting in gross proceeds to us of $325.0 million (the "Preferred Unit Transaction"). We used the net proceeds from the Preferred Unit Transaction to purchase 325,000 preferred units of the Operating Company ("OpCo preferred units"). The Operating Company in turn used the net proceeds to fund a portion of the LongPoint Acquisition. The Series A preferred units rank senior to our common units with respect to distribution rights and rights upon liquidation.

Until the conversion of the Series A preferred units into common units or their redemption, holders of the Series A preferred units are entitled to receive cumulative quarterly distributions equal to 6.0% per annum plus accrued and unpaid distributions. We have the right, in any four non-consecutive quarters, to elect not to pay such quarterly distribution in cash and instead have the unpaid distribution amount added to the liquidation preference at the rate of 10.0% per annum. If we make such an election in consecutive quarters or if we fail to pay in full, in cash and when due, any distribution owed to the Series A preferred units or otherwise materially breaches its obligations to the holders of the Series A preferred units, the distribution rate will increase to 20.0% per annum until the accumulated distributions are paid in full in cash, or any such material breach is cured, as applicable. Each holder of Series A preferred units has the right to share in any special distributions by us of cash, securities or other property pro rata with the common units on an as-converted basis, subject to customary adjustments. We cannot declare or make any distributions, redemptions, or repurchases on any junior securities, including any of their common units, prior to paying the quarterly distribution payable to the Series A preferred units, including any previously accrued and unpaid distributions.

Beginning with the earlier of (i) the second anniversary of the original issuance date and (ii) immediately prior to our liquidation, the Series A Purchasers may, at any time (but not more often than once per quarter), elect to convert all or any portion of their Series A preferred units into a number of common units determined by multiplying the number of Series A preferred units to be converted by the then-applicable conversion rate, provided that (a) any conversion is for an amount of common units with an aggregate value of at least $10.0 million or such lesser amount that covers all of the holders' remaining Series A preferred units and (b) the closing price of the common units is at least 130% of the conversion price of $15.07, subject to certain anti-dilution adjustments (the “Conversion Price”) for 20 trading days during the 30-trading day period immediately preceding the conversion notice.

At any time on or after the second anniversary of the original issuance date, we will have the option to convert all or any portion of the Series A preferred units into a number of common units determined by the then-applicable conversion rate, provided that (i) any conversion is for an amount of common units with an aggregate value of at least $10.0 million or such lesser amount that covers all of the holders’ Series A preferred units, (ii) the common units are listed for, or admitted to, trading on a national securities exchange, (iii) the closing price of the common units is at least 160% of the Conversion Price for 20 trading days during the 30-trading day period immediately preceding the conversion notice and (iv) we have an effective registration statement on file with the SEC covering resales of the underlying common units to be received by the holders of Series A preferred units upon such conversion.

The Series A preferred units are redeemable at the option of the Series A Purchasers after seven years. The Series A preferred units may be redeemed by us at any time or in the event of a change of control. The Series A preferred units may be redeemed for a cash amount per Series A preferred unit equal to the product of (a) the number of outstanding Series A preferred units multiplied by (b) the greatest of (i) an amount (together with all prior distributions made in respect of such Series A preferred unit) necessary to achieve the Minimum IRR (as defined below), (ii) an amount (together with all prior distributions made in respect of such Series A preferred unit) necessary to achieve a return on investment equal to 1.2 times with respect to such Series A preferred unit and (iii) the Series A issue price plus accrued and unpaid distributions.

For purposes of the Series A preferred units, “Minimum IRR” means as of any measurement date: (a) prior to the fifth anniversary of the original issuance date, a 12.0% internal rate of return with respect to the Series A preferred units; (b) on or after the fifth anniversary of the original issuance date and prior to the sixth anniversary of the original issuance date, a 13.0% internal rate of return with respect to the Series A preferred units; and (c) on or after the sixth anniversary of the original issuance date, a 14.0% internal rate of return with respect to the Series A preferred units.

In connection with the issuance of the Series A preferred units, we granted holders of the Series A preferred units board observer rights beginning on the fifth anniversary of the original issuance date, board appointment rights beginning on the sixth anniversary of the original issuance date, and in the case of events of default with respect to the Series A preferred units, the right to appoint two members of the board beginning on the seventh anniversary of the original issuance date.

The terms of the Series A preferred units contain covenants preventing us from taking certain actions without the approval of the holders of $66^2/_3$% of the outstanding Series A preferred units, voting separately as a class.

Equity Offering

On August 7, 2023, we completed an underwritten public offering of 8,337,500 common units for net proceeds of approximately $110.7 million (the “2023 Equity Offering”). We used the net proceeds from the 2023 Equity Offering to purchase OpCo common units. The Operating Company in turn used the net proceeds to repay approximately $90.0 million of the outstanding borrowings under our secured revolving credit facility. The Operating Company used the remainder of the net proceeds of the 2023 Equity Offering for general corporate purposes.

Quarterly Distributions

On November 2, 2023, the General Partner’s Board of Directors (the “Board of Directors”) declared a quarterly cash distribution of $0.51 per common unit and OpCo common unit for the quarter ended September 30, 2023. We intend to pay the distributions on November 20, 2023 to common unitholders and OpCo common unitholders of record as of the close of business on November 13, 2023.

We will pay a pro-rated quarterly cash distribution on the Series A preferred units of approximately $1.0 million for the quarter ended September 30, 2023. We intend to pay the distribution subsequent to November 13, 2023 and prior to the distribution on the common units and OpCo common units.

Business Environment

Russia / Ukraine Conflict and Conflict in the Middle East

In February 2022, Russia invaded Ukraine and is still engaged in active armed conflict against the country. In October 2023, armed active conflict began in the Middle East and is still active These conflicts and the sanctions imposed in response have led to regional instability and caused dramatic fluctuations in global financial markets and have increased the level of global economic and political uncertainty, including uncertainty about world-wide oil supply and demand, which in turn has increased volatility in commodity prices. To date, we have not experienced a material impact to operations or the consolidated financial statements as a result of these conflicts; however, we will continue to monitor for events that could materially impact us.

Commodity Prices and Demand

Oil and natural gas prices have been historically volatile and may continue to be volatile in the future. As noted above, the supply and demand imbalance resulting from various OPEC announcements and the current conflict between Russia and Ukraine have created increased volatility in oil and natural gas prices. The table below demonstrates such volatility for the periods presented as reported by the United States Energy Information Administration (the “EIA”).

	Nine Months Ended September 30, 2023		Nine Months Ended September 30, 2022	
	High	Low	High	Low
Oil ($/Bbl)	$ 93.67	$ 66.61	$ 123.64	$ 75.99
Natural gas ($/MMBtu)	$ 3.78	$ 1.74	$ 9.85	$ 3.73

On October 23, 2023, the West Texas Intermediate posted price for crude oil was $85.49 per Bbl and the Henry Hub spot market price of natural gas was $2.65 per MMBtu.

The following table, as reported by the EIA, sets forth the average daily prices for oil and natural gas.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
Oil ($/Bbl)	$ 82.25	$ 93.06	$ 77.27	$ 98.96
Natural gas ($/MMBtu)	$ 2.59	$ 8.03	$ 2.46	$ 6.74

Rig Count

Drilling on our acreage is dependent upon the exploration and production companies that lease our acreage. As such, we monitor rig counts in an effort to identify existing and future leasing and drilling activity on our acreage.

The Baker Hughes United States Rotary Rig count decreased by 19.5% to 600 active land rigs at September 30, 2023 compared to 745 active land rigs at September 30, 2022. The 600 active land rigs at September 30, 2023 decreased by 8.1% from 653 active land rigs at June 30, 2023. The overall decrease in rig count at September 30, 2023 compared September 30, 2022 is primarily attributable to the volatility and decrease in the average daily prices for oil and natural gas.

The following table summarizes the number of active rigs operating on our acreage by United States basins and producing regions for the periods indicated:

	September 30,	
Basin or Producing Region	**2023**	**2022**
Permian Basin	56	39
Mid-Continent	18	9
Terryville/Cotton Valley/Haynesville	16	18
Appalachian Basin	1	1
Bakken/Williston Basin	5	4
Eagle Ford	2	6
DJ Basin/Rockies/Niobrara	1	1
Other	—	1
Total	99	79

Sources of Our Revenue

Our revenues are derived from royalty payments we receive from our operators based on the sale of oil, natural gas and NGL production, as well as the sale of NGLs that are extracted from natural gas during processing. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices.

The following table presents the breakdown of our oil, natural gas, and NGL revenues for the following periods:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	**2022**	**2023**	**2022**
Revenue				
Oil revenue	73 %	43 %	67 %	46 %
Natural gas revenue	18 %	48 %	24 %	43 %
NGL revenue	9 %	9 %	9 %	11 %
	100 %	100 %	100 %	100 %

We have entered into oil and natural gas commodity derivative agreements, which extend through September 2025, to establish, in advance, a price for the sale of a portion of the oil and natural gas produced from our mineral and royalty interests.

Non-GAAP Financial Measures

Adjusted EBITDA and Cash Available for Distribution on Common Units

Adjusted EBITDA and cash available for distribution on common units are used as supplemental non-GAAP financial measures (as defined below) by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. We believe Adjusted EBITDA and cash available for distribution on common units are useful because they allow us to more effectively evaluate our operating performance and compare the results of our operations period to period without regard to our financing methods or capital structure. In addition, management uses Adjusted EBITDA to evaluate cash flow available to pay distributions to our unitholders.

We define Adjusted EBITDA as net income (loss), net of depreciation and depletion expense, interest expense, income taxes, non cash unit based compensation, loss on extinguishment of debt, unrealized gains and losses on derivative instruments, cash distribution from affiliate, equity income (loss) in affiliate, gains and losses on sales of assets and operational impacts of VIEs, which include general and administrative expense and interest income. Adjusted EBITDA is not a measure of net income (loss) or net cash provided by operating activities as determined by generally accepted accounting principles in the United States (“GAAP”). We exclude the items listed above from net income (loss) in arriving at Adjusted EBITDA because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Certain items excluded from Adjusted EBITDA are significant components in understanding and assessing a company’s financial performance, such as a company’s cost of capital and tax structure, as well as historic costs of depreciable assets, none of which are components of Adjusted EBITDA. We define cash available for distribution on common units as Adjusted EBITDA, less cash needed for debt service and other contractual obligations, tax obligations, fixed charges and reserves for future operating or capital needs that the Board of Directors may determine is appropriate.

Adjusted EBITDA and cash available for distribution on common units should not be considered an alternative to net income (loss), oil, natural gas and NGL revenues, net cash flows provided by operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. Our computations of Adjusted EBITDA and cash available for distribution on common units may not be comparable to other similarly titled measures of other companies.

The tables below present a reconciliation of Adjusted EBITDA and cash available for distribution on common units to net income and net cash provided by operating activities, our most directly comparable GAAP financial measures, for the periods indicated (unaudited).

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
Reconciliation of net income to Adjusted EBITDA and cash available for distribution on common units:				
Net income	$ 18,481,038	$ 43,845,114	$ 65,177,607	$ 95,546,524
Depreciation and depletion expense	23,060,163	11,326,791	60,280,666	33,359,915
Interest expense	6,680,661	3,667,534	18,485,183	9,868,679
Cash distribution from affiliate	—	—	—	385,326
Income tax expense (benefit)	128,359	(224,883)	2,440,399	1,850,357
EBITDA	48,350,221	58,614,556	146,383,855	141,010,801
Unit-based compensation	3,325,891	2,981,903	9,785,631	8,125,736
Loss on extinguishment of debt	—	—	480,244	—
Loss (gain) on derivative instruments, net of settlements	4,097,565	(13,388,100)	(11,002,749)	(1,271,103)
Cash distribution from affiliate	—	—	—	473,812
Equity income in affiliate	—	(23,727)	—	(3,658,460)
Consolidated variable interest entities related:				
Interest earned on marketable securities in trust account	—	(1,188,256)	(3,508,691)	(1,512,777)
General and administrative expense	—	527,634	927,699	1,857,593
Consolidated Adjusted EBITDA	55,773,677	47,524,010	143,065,989	145,025,602
Adjusted EBITDA attributable to non-controlling interest	(12,278,201)	(5,954,026)	(31,287,102)	(18,187,707)
Adjusted EBITDA attributable to Kimbell Royalty Partners, LP	43,495,476	41,569,984	111,778,887	126,837,895
Adjustments to reconcile Adjusted EBITDA to cash available for distribution				
Cash interest expense	4,645,744	2,624,190	13,211,771	7,024,551
Cash distributions on Series A preferred units	749,945	—	749,945	—
Cash income tax expense (refund)	—	1,024,000	(639,325)	3,067,374
Distributions on Class B units	20,854	8,211	67,939	34,032
Cash available for distribution on common units	$ 38,078,933	$ 37,913,583	$ 98,388,557	$ 116,711,938

	Three Months Ended September 30, 2023	Three Months Ended September 30, 2022	Nine Months Ended September 30, 2023	Nine Months Ended September 30, 2022
Reconciliation of net cash provided by operating activities to Adjusted EBITDA and cash available for distribution on common units:				
Net cash provided by operating activities	$ 36,386,578	$ 51,550,250	$ 114,958,713	$ 128,005,890
Interest expense	6,680,661	3,667,534	18,485,183	9,868,679
Income tax expense (benefit)	128,359	(224,883)	2,440,399	1,850,357
Amortization of right-of-use assets	(83,517)	(80,541)	(251,175)	(237,839)
Amortization of loan origination costs	(405,244)	(480,057)	(1,414,074)	(1,381,717)
Loss on extinguishment of debt	—	—	(480,244)	—
Equity income in affiliate, net	—	23,727	—	273,135
Forfeiture of restricted units	—	—	—	19,813
Unit-based compensation	(3,325,891)	(2,981,903)	(9,785,631)	(8,125,736)
(Loss) gain on derivative instruments, net of settlements	(4,097,565)	13,388,100	11,002,749	1,271,103
Changes in operating assets and liabilities:				
Oil, natural gas and NGL receivables	16,313,898	(7,208,042)	14,326,575	11,240,327
Accounts receivable and other current assets	(280,154)	450,477	(707,259)	(455,642)
Accounts payable	(854,707)	678,811	(1,014,264)	(63,161)
Other current liabilities	(2,200,296)	(1,240,468)	(5,631,591)	(3,099,504)
Operating lease liabilities	88,099	81,597	258,430	241,314
Consolidated variable interest entities related:				
Interest earned on marketable securities in trust account	—	1,188,256	3,508,691	1,512,777
Other assets and liabilities	—	(198,302)	687,353	91,005
EBITDA	48,350,221	58,614,556	146,383,855	141,010,801
Add:				
Unit-based compensation	3,325,891	2,981,903	9,785,631	8,125,736
Loss on extinguishment of debt	—	—	480,244	—
Loss (gain) on derivative instruments, net of settlements	4,097,565	(13,388,100)	(11,002,749)	(1,271,103)
Cash distribution from affiliate	—	—	—	473,812
Equity income in affiliate	—	(23,727)	—	(3,658,460)
Consolidated variable interest entities related:				
Interest earned on marketable securities in Trust Account	—	(1,188,256)	(3,508,691)	(1,512,777)
General and administrative expense	—	527,634	927,699	1,857,593
Consolidated Adjusted EBITDA	55,773,677	47,524,010	143,065,989	145,025,602
Adjusted EBITDA attributable to non-controlling interest	(12,278,201)	(5,954,026)	(31,287,102)	(18,187,707)
Adjusted EBITDA attributable to Kimbell Royalty Partners, LP	43,495,476	41,569,984	111,778,887	126,837,895
Adjustments to reconcile Adjusted EBITDA to cash available for distribution				
Cash interest expense	4,645,744	2,624,190	13,211,771	7,024,551
Cash distributions on Series A preferred units	749,945	—	749,945	—
Cash income tax expense (refund)	—	1,024,000	(639,325)	3,067,374
Distributions on Class B units	20,854	8,211	67,939	34,032
Cash available for distribution on common units	$ 38,078,933	$ 37,913,583	$ 98,388,557	$ 116,711,938

Factors Affecting the Comparability of Our Results to Our Historical Results

Our historical financial condition and results of operations may not be comparable, either from period to period or going forward, to our future financial condition and results of operations, for the reasons described below.

Ongoing Acquisition Activities

Acquisitions are an important part of our growth strategy, and we expect to pursue acquisitions of mineral and royalty interests from third parties, affiliates of our Sponsors and the Contributing Parties. As a part of these efforts, we often engage in discussions with potential sellers or other parties regarding the possible purchase of or investment in mineral and royalty interests, including in connection with a dropdown of assets from affiliates of our Sponsors and the Contributing Parties. Such efforts may involve participation by us in processes that have been made public and involve a number of potential buyers or investors, commonly referred to as “auction” processes, as well as situations in which we believe we are the only party or one of a limited number of parties who are in negotiations with the potential seller or other party. These acquisition and investment efforts often involve assets which, if acquired or constructed, could have a material effect on our financial condition and results of operations. Material acquisitions that would impact the comparability of our results for the three and nine months ended September 30, 2023 and 2022 include the acquisition of certain mineral and royalty assets held by Hatch Royalty LLC (the “Hatch Acquisition”), the MB Minerals Acquisition and the LongPoint Acquisition.

Further, the affiliates of our Sponsors and Contributing Parties have no obligation to sell any assets to us or to accept any offer that we may make for such assets, and we may decide not to acquire such assets even if such parties offer them to us. We may decide to fund any acquisition, including any potential dropdowns, with cash, common units, other equity securities, proceeds from borrowings under our secured revolving credit facility or the issuance of debt securities, or any combination thereof. In addition to acquisitions, we also consider from time to time divestitures that may benefit us and our unitholders.

We typically do not announce a transaction until after we have executed a definitive agreement. Past experience has demonstrated that discussions and negotiations regarding a potential transaction can advance or terminate in a short period of time. Moreover, the closing of any transaction for which we have entered into a definitive agreement may be subject to customary and other closing conditions, which may not ultimately be satisfied or waived. Accordingly, we can give no assurance that our current or future acquisition or investment efforts will be successful or that our strategic asset divestitures will be completed. Although we expect the acquisitions and investments we make to be accretive in the long term, we can provide no assurance that our expectations will ultimately be realized. We will not know the immediate results of any acquisition until after the acquisition closes, and we will not know the long-term results for some time thereafter.

Impairment of Oil and Natural Gas Properties

Accounting standards require that we periodically review the carrying value of our properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our properties. The net capitalized costs of proved oil and natural gas properties are subject to a full-cost ceiling limitation for which the costs are not allowed to exceed their related estimated future net revenues discounted at 10%. To the extent capitalized costs of evaluated oil and natural gas properties, net of accumulated depreciation, depletion, amortization and impairment, exceed estimated discounted future net revenues of proved oil and natural gas reserves, the excess capitalized costs are charged to expense. The risk that we will be required to recognize impairments of our oil and natural gas properties increases during periods of low commodity prices. In addition, impairments would occur if we were to experience significant downward adjustments to our estimated proved reserves or the present value of estimated future net revenues. An impairment recognized in one period may not be reversed in a subsequent period even if higher oil and natural gas prices increase the cost center ceiling applicable to the subsequent period. We did not record an impairment on our oil and natural gas properties for the three and nine months ended September 30, 2023 and 2022.

Because we do not intend to book proved undeveloped reserves going forward, additional impairment charges could be recorded in connection with future acquisitions. Further, if the price of oil, natural gas and NGLs decreases in future periods, we may be required to record additional impairments as a result of the full-cost ceiling limitation.

Results of Operations

The table below summarizes our revenue and expenses and production data for the periods indicated (unaudited).

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	2023	2022
Operating Results:				
Revenue				
Oil, natural gas and NGL revenues	$ 69,237,603	$ 73,867,992	$ 183,635,976	$ 217,543,364
Lease bonus and other income	2,543,240	171,702	5,021,766	2,039,154
(Loss) gain on commodity derivative instruments, net	(4,576,570)	(1,116,722)	6,215,265	(40,194,369)
Total revenues	67,204,273	72,922,972	194,873,007	179,388,149
Costs and expenses				
Production and ad valorem taxes	4,986,878	4,518,580	14,669,037	13,542,285
Depreciation and depletion expense	23,060,163	11,326,791	60,280,666	33,359,915
Marketing and other deductions	3,508,500	3,068,244	9,177,998	10,639,314
General and administrative expenses	10,358,674	7,482,814	26,562,100	21,938,249
Consolidated variable interest entities related:				
General and administrative expense	—	527,634	927,699	1,857,593
Total costs and expenses	41,914,215	26,924,063	111,617,500	81,337,356
Operating income	25,290,058	45,998,909	83,255,507	98,050,793
Other income (expense)				
Equity income in affiliate	—	23,727	—	3,658,460
Interest expense	(6,680,661)	(3,667,534)	(18,485,183)	(9,868,679)
Loss on extinguishment of debt	—	—	(480,244)	—
Other income (expense)	—	76,873	(180,765)	4,043,530
Consolidated variable interest entities related:				
Interest earned on marketable securities in trust account	—	1,188,256	3,508,691	1,512,777
Net income before income taxes	18,609,397	43,620,231	67,618,006	97,396,881
Income tax expense (benefit)	128,359	(224,883)	2,440,399	1,850,357
Net income	18,481,038	43,845,114	65,177,607	95,546,524
Distribution and accretion on Series A preferred units	(1,040,572)	—	(1,040,572)	—
Net income attributable to non-controlling interests in OpCo	(3,839,401)	(5,493,117)	(13,700,261)	(11,975,886)
Distribution on Class B units	(20,854)	(8,211)	(67,939)	(34,032)
Net income attributable to common units of Kimbell Royalty Partners, LP	$ 13,580,211	$ 38,343,786	$ 50,368,835	$ 83,536,606
Production Data:				
Oil (Bbls)	622,831	345,867	1,622,432	1,058,423
Natural gas (Mcf)	5,589,952	5,130,753	16,384,109	15,146,635
Natural gas liquids (Bbls)	264,967	177,651	697,913	558,806
Combined volumes (Boe) (6:1)	1,819,457	1,378,644	5,051,030	4,141,668

Comparison of the Three Months Ended September 30, 2023 to the Three Months Ended September 30, 2022

Oil, Natural Gas and NGL Revenues

For the three months ended September 30, 2023, our oil, natural gas and NGL revenues were $69.2 million, a decrease of $4.7 million from $73.9 million for the three months ended September 30, 2022. The decrease in oil, natural gas and NGL revenues was primarily related to the decrease in the average prices we received for oil, natural gas and NGL production, partially offset by an increase in production volumes for the three months ended September 30, 2023 as discussed below.

Our revenues are a function of oil, natural gas, and NGL production volumes sold and average prices received for those volumes. The production volumes were 1,819,457 Boe or 19,777 Boe/d, for the three months ended September 30, 2023, an increase of 440,813 Boe or 4,792 Boe/d, from 1,378,644 Boe or 14,985 Boe/d, for the three months ended September 30, 2022. The increase in production for the three months ended September 30, 2023 was primarily attributable to production associated with the Hatch Acquisition and the MB Minerals Acquisition, and to a lesser extent, production associated with the LongPoint Acquisition.

Our operators received an average of $81.53 per Bbl of oil, $2.21 per Mcf of natural gas and $23.10 per Bbl of NGL for the volumes sold during the three months ended September 30, 2023 compared to $92.65 per Bbl of oil, $6.92 per Mcf of natural gas and $35.50 per Bbl of NGL for the volumes sold during the three months ended September 30, 2022. These average prices received during the three months ended September 30, 2023 decreased 12.0% or $11.12 per Bbl of oil and 68.1% or $4.71 per Mcf of natural gas as compared to the three months ended September 30, 2022. This change is consistent with prices experienced in the market, specifically when compared to the EIA average price decreases of 11.6% or $10.81 per Bbl of oil and 67.7% or $5.44 per Mcf of natural gas for the comparable periods.

Lease Bonus and Other Income

Lease bonus and other income was $2.5 million for the three months ended September 30, 2023 compared to $0.2 million for the three months ended September 30, 2022. The $2.3 million increase in lease bonus and other income was primarily related to a legal settlement received during the three months ended September 30, 2023.

Loss on Commodity Derivative Instruments

Loss on commodity derivative instruments for the three months ended September 30, 2023 included $4.1 million of mark-to-market losses and $0.5 million of losses on the settlement of commodity derivative instruments compared to $16.7 million of mark-to-market gains and $17.8 million of losses on the settlement of commodity derivative instruments for the three months ended September 30, 2022. We recorded a mark-to-market loss for the three months ended September 30, 2023 as a result of the increase in strip pricing from the three months ended June 30, 2023. We recorded a mark-to-market gain for the three months ended September 30, 2022 as a result of the maturity of derivative contracts with lower strike pricing, offset by realized losses on the settlement of commodity derivative instruments.

Production and Ad Valorem Taxes

Production and ad valorem taxes for the three months ended September 30, 2023 were $5.0 million, an increase of $0.5 million from $4.5 million for the three months ended September 30, 2022. The increase in production and ad valorem taxes was primarily attributable to the Hatch Acquisition and the MB Minerals Acquisition, and to a lesser extent, and the LongPoint Acquisition, partially offset by the decrease in the average prices we received for oil, natural gas and NGL production.

Depreciation and Depletion Expense

Depreciation and depletion expense for the three months ended September 30, 2023 was $23.1 million, an increase of $11.8 million from $11.3 million for the three months ended September 30, 2022. The increase in depreciation and depletion expense was due to the Hatch Acquisition, the MB Minerals Acquisition and the LongPoint Acquisition, which significantly increased our net capitalized oil and natural gas properties.

Depletion is the amount of cost basis of oil and natural gas properties at the beginning of a period attributable to the volume of hydrocarbons extracted during such period, calculated on a units-of-production basis. Estimates of proved developed reserves are a major component in the calculation of depletion. Our average depletion rate per barrel was $12.62 for the three months ended September 30, 2023, an increase of $4.56 per barrel from the $8.06 average depletion rate per barrel for the three months ended September 30, 2022. The increase in the depletion rate was due to the Hatch Acquisition, the MB Minerals Acquisition and the LongPoint Acquisition, which significantly increased our net capitalized oil and natural gas properties.

Marketing and Other Deductions

Our marketing and other deductions include product marketing expense, which is a post-production expense. Marketing and other deductions for the three months ended September 30, 2023 were $3.5 million, a decrease of $0.4 million from $3.1 million for the three months ended September 30, 2022. The decrease in marketing and other deductions was primarily related to the decrease in the average prices we received for oil, natural gas and NGL production for the three months ended September 30, 2023, partially offset by marketing and other deductions associated with the Hatch Acquisition, the MB Minerals Acquisition and the LongPoint Acquisition.

General and Administrative Expenses

General and administrative expenses for the three months ended September 30, 2023 were $10.4 million an increase of $2.9 million from $7.5 million for the three months ended September 30, 2022. Included within general and administrative expenses are non-cash expenses for unit-based compensation as a result of the amortization of restricted units that have been issued by us over various periods. The increase in general and administrative expenses was attributable to a $0.3 million increase in unit-based compensation expense, expenses related to a one-time cash bonus paid to employees and cash general and administrative expenses resulting from an increase in our costs associated with company growth.

Interest Expense

Interest expense for the three months ended September 30, 2023 was $6.7 million compared to $3.7 million for the three months ended September 30, 2022. The increase in interest expense was primarily due to a 3.1% increase in the weighted average interest rate on the Partnership's outstanding borrowings for the three months ended September 30, 2023 and also due to an increase in the overall long-term debt balance as a result of borrowings associated with the Hatch Acquisition, the MB Minerals Acquisition and the LongPoint Acquisition.

Income Tax Expense

We recorded an income tax expense of $0.1 million for the three months ended September 30, 2023. The income tax expense recorded during the three months ended September 30, 2023 was due to a change in the estimated income tax expense for the year ended December 31, 2023. We recorded a benefit from income taxes of $0.2 million for the three months ended September 30, 2022. The benefit from income taxes recorded during the three months ended September 30, 2022 was due to a change in the estimated income tax expense for the year ended December 31, 2022.

Comparison of the Nine Months Ended September 30, 2023 to the Nine Months Ended September 30, 2022

Oil, Natural Gas and NGL Revenues

For the nine months ended September 30, 2023, our oil, natural gas and NGL revenues were $183.6 million, a decrease of $33.9 million from $217.5 million for the nine months ended September 30, 2022. The decrease in oil, natural gas and NGL revenues was primarily related to the decrease in the average prices we received for oil, natural gas and NGL production, partially offset by an increase in production volumes for the nine months ended September 30, 2023 as discussed below.

Our revenues are a function of oil, natural gas, and NGL production volumes sold and average prices received for those volumes. The production volumes were 5,051,030 Boe or 18,523 Boe/d, for the nine months ended September 30, 2023, an increase of 909,362 Boe or 3,654 Boe/d, from 4,141,668 Boe or 14,869 Boe/d, for the nine months ended September 30, 2022. The increase in production for the nine months ended September 30, 2023 was primarily attributable to production associated with the Hatch Acquisition and the MB Minerals Acquisition, and to a lesser extent, production associated with the LongPoint Acquisition.

Our operators received an average of $76.17 per Bbl of oil, $2.66 per Mcf of natural gas and $23.67 per Bbl of NGL for the volumes sold during the nine months ended September 30, 2023 compared to $94.84 per Bbl of oil, $6.23 per Mcf of natural gas and $40.71 per Bbl of NGL for the volumes sold during the nine months ended September 30, 2022. These average prices received during the nine months ended September 30, 2023 decreased 19.7% or $18.67 per Bbl of oil and 57.3% or 3.57 per Mcf of natural gas as compared to the nine months ended September 30, 2022. This change is consistent with prices experienced in the market, specifically when compared to the EIA average price decreases of 21.9% or $21.69 per Bbl of oil and 63.5% or $4.28 per Mcf of natural gas for the comparable periods.

Lease Bonus and Other Income

Lease bonus and other income was $5.0 million for the nine months ended September 30, 2023 compared to $2.0 million for the nine months ended September 30, 2022. The increase in lease bonus and other income is primarily related to legal settlements received during the nine months ended September 30, 2023.

Gain (Loss) on Commodity Derivative Instruments

Gain on commodity derivative instruments for the nine months ended September 30, 2023 included $11.0 million of mark-to-market gains and $4.8 million of losses on the settlement of commodity derivative instruments compared to $3.0 million of mark-to-market losses and $43.2 million of losses on the settlement of commodity derivative instruments for the nine months ended September 30, 2022. We recorded a mark-to-market gain for the nine months ended September 30, 2023 as a result of the maturity of derivative contracts with lower strike pricing. This gain was offset by the realized losses on the settlement of commodity derivative instruments. We recorded a mark-to-market loss for the nine months ended September 30, 2022 as a result of the increase in the strip pricing of oil and natural gas from December 31, 2021.

Production and Ad Valorem Taxes

Production and ad valorem taxes for the nine months ended September 30, 2023 were $14.7 million, an increase of $1.2 million from $13.5 million for the nine months ended September 30, 2022. The increase in production and ad valorem taxes was primarily attributable to the Hatch Acquisition and the MB Minerals Acquisition, and to a lesser extent, the LongPoint Acquisition. The increase was partially offset by the decrease in the average prices we received for oil, natural gas and NGL production.

Depreciation and Depletion Expense

Depreciation and depletion expense for the nine months ended September 30, 2023 was $60.3 million, an increase of $26.9 million from $33.4 million for the nine months ended September 30, 2022. The increase in depreciation and depletion expense was due to the Hatch Acquisition, the MB Minerals Acquisition and the LongPoint Acquisition, which significantly increased our net capitalized oil and natural gas properties.

Depletion is the amount of cost basis of oil and natural gas properties at the beginning of a period attributable to the volume of hydrocarbons extracted during such period, calculated on a units-of-production basis. Estimates of proved developed reserves are a major component in the calculation of depletion. Our average depletion rate per barrel was $11.88 for the nine months ended September 30, 2023, an increase of $4.04 per barrel from the $7.84 average depletion rate per barrel for the nine months ended September 30, 2022. The increase in the depletion rate was due to the Hatch Acquisition, the MB Minerals Acquisition and the LongPoint Acquisition, which significantly increased our net capitalized oil and natural gas properties.

Marketing and Other Deductions

Our marketing and other deductions include product marketing expense, which is a post-production expense. Marketing and other deductions for the nine months ended September 30, 2023 were $9.2 million, a decrease of $1.4 million from $10.6 million for the nine months ended September 30, 2022. The decrease in marketing and other deductions was primarily related to the decrease in the average prices we received for oil, natural gas and NGL production for the nine months ended September 30, 2023, partially offset by marketing and other deductions associated with the Hatch Acquisition and the MB Minerals Acquisition, and to a lesser extent, the LongPoint Acquisition.

General and Administrative Expenses

General and administrative expenses for the nine months ended September 30, 2023 were $26.6 million, an increase of $4.7 million from $21.9 million for the nine months ended September 30, 2022. Included within general and administrative expenses are non-cash expenses for unit-based compensation as a result of the amortization of restricted units that have been issued by us over various periods. The increase in general and administrative expenses was attributable to a $1.7 million increase in unit-based compensation expense, expenses related to a one-time cash bonus paid to employees and cash general and administrative expenses resulting from an increase in our costs associated with company growth.

Interest Expense

Interest expense for the nine months ended September 30, 2023 was $18.5 million compared to $9.9 million for the nine months ended September 30, 2022. The increase in interest expense was primarily due to a 3.8% increase in the weighted average interest rate on the Partnership's outstanding borrowings for the nine months ended September 30, 2023 and also due to an increase in the overall long-term debt balance as a result of borrowings associated with the Hatch Acquisition, the MB Minerals Acquisition and The LongPoint.

Income Tax Expense

We recorded an income tax expense of $2.4 million for the nine months ended September 30, 2023. The income tax expense recorded during the nine months ended September 30, 2023 was due to a change in the estimated income tax expense for the year ended December 31, 2023. We recorded an income tax expense of $1.9 million for the nine months ended September 30, 2022. The income tax expense recorded during the nine months ended September 30, 2022 was due to the significant increase in commodity prices which generated forecasted taxable net income for the year ended December 31, 2022.

Liquidity and Capital Resources

Overview

Our primary sources of liquidity are cash flows from operations and equity and debt financings, and our primary uses of cash are for distributions to our unitholders and for growth capital expenditures, including the acquisition of mineral and royalty interests in oil and natural gas properties. On June 13, 2023, we entered into the A&R Credit Agreement (as defined below). On July 24, 2023, we entered into the First Amendment (as defined below) to the A&R Credit Agreement that, among other things, (i) decrease the frequency of and increase the threshold for excess cash determinations from $30.0 million to $50.0 million, and (ii) permit us to issue certain preferred equity interests. See "Indebtedness" below for further discussion of our secured revolving credit facility.

Cash Distribution Policy

The limited liability company agreement of the Operating Company requires it to distribute all of its cash on hand at the end of each quarter in an amount equal to its available cash for such quarter. In turn, our partnership agreement requires us to distribute all of our cash on hand at the end of each quarter in an amount equal to our available cash for such quarter. Available cash for each quarter will be determined by the Board of Directors following the end of such quarter. "Available cash," as used in this context, is defined in our partnership agreement and in the limited liability company agreement of the Operating Company. We expect that the Operating Company's available cash for each quarter will generally equal its Adjusted EBITDA for the quarter, less cash needed for debt service and other contractual obligations and fixed charges and reserves for future operating or capital needs that the Board of Directors may determine is appropriate, and we expect that our available cash for each quarter will generally equal our Adjusted EBITDA for the quarter (and will be our proportional share of the available cash distributed by the Operating Company for that quarter), less cash needs for debt service and other contractual obligations, tax obligations, fixed charges and reserves for future operating or capital needs that the Board of Directors may determine is appropriate.

The Board of Directors approved the allocation of 25% of our cash available for distribution on common units for the third quarter of 2023 for the repayment of $16.2 million in outstanding borrowings under our secured revolving credit facility during its determination of "available cash" for the third quarter of 2023. With respect to future quarters, the Board of Directors intends to continue to allocate a portion of our cash available for distribution on common units to the repayment of outstanding borrowings under our secured revolving credit facility and may allocate such cash in other manners in which the Board of Directors determines to be appropriate at the time. The Board of Directors may further change its policy with respect to cash distributions in the future.

We do not currently maintain a material reserve of cash for the purpose of maintaining stability or growth in our quarterly distribution, nor do we intend to incur debt to pay quarterly distributions, although the Board of Directors may change this policy.

It is our intent, subject to market conditions, to finance acquisitions of mineral and royalty interests that increase our asset base largely through external sources, such as borrowings under our secured revolving credit facility and the issuance of equity and debt securities. For example, we issued 7,272,821 OpCo common units and an equal number of Class B units as partial consideration in connection with the Hatch Acquisition, 5,369,218 OpCo common units and an equal number of Class B units and 557,302 common units as partial consideration in connection with the MB Minerals Acquisition and we completed the LongPoint Acquisition partially with net proceeds from the Preferred Unit Transaction. The Board of Directors may choose to reserve a portion of cash generated from operations to finance such acquisitions as well. We do not currently intend to (i) maintain excess distribution coverage for the purpose of maintaining stability or growth in our quarterly distribution, (ii) otherwise reserve cash for distributions or (iii) incur debt to pay quarterly distributions, although the Board of Directors may do so if they believe it is warranted. See “Recent Developments—Quarterly Distributions” above for discussion of our third quarter 2023 distributions.

Cash Flows

The table below presents our cash flows for the periods indicated.

	Nine Months Ended September 30,	
	2023	2022
Cash Flow Data:		
Net cash provided by operating activities	$ 114,958,713	$ 128,005,890
Net cash used in investing activities	(246,113,134)	(233,997,215)
Net cash provided by financing activities	145,656,712	116,045,612
Net increase in cash and cash equivalents	$ 14,502,291	$ 10,054,287

Operating Activities

Our operating cash flow is impacted by many variables, the most significant of which are changes in oil, natural gas and NGL production volumes due to acquisitions or other external factors and changes in prices for oil, natural gas and NGLs. 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. Cash flows provided by operating activities for the nine months ended September 30, 2023 were $115.0 million, a decrease of $13.0 million compared to $128.0 million for the nine months ended September 30, 2022.

Investing Activities

Cash flows used in investing activities for the nine months ended September 30, 2023 were $246.1 million compared to $234.0 million for the nine months ended September 30, 2022. For the nine months ended September 30, 2023, cash flows used in investing activities included $490.1 million used to fund costs associated with the MB Minerals Acquisition and the LongPoint Acquisition and $0.1 million used to fund the purchase of equipment, partially offset by $243.2 million of cash received from investment held in trust related to TGR and $0.9 million in cash received from the dissolution of TGR.

For the nine months ended September 30, 2022, cash flows used in investing activities include $236.9 million of investments held in marketable securities related to TGR, $0.4 million used to fund costs associated with the acquisition of all of the equity interests in certain subsidiaries owned by Caritas Royalty Fund LLC and certain of its affiliates and $0.1 million used to fund the purchase of equipment, partially offset by $3.5 million in cash distributions received in connection to the joint venture with Springbok SKR Capital Company, LLC and Rivercrest Capital Partners, LP.

Financing Activities

Cash flows provided by financing activities were $145.7 million for the nine months ended September 30, 2023 compared to $116.0 million for the nine months September 30, 2022. Cash flows used in financing activities for the nine months ended September 30, 2023 consists of $314.0 million in net proceeds from the issuance of Series A preferred units, $201.1 million of additional borrowings under our secured revolving credit facility, $110.7 million in proceeds from the 2023 Equity Offering, and $0.3 million in Class B contributions, partially offset by $243.2 million of distributions to common unitholders of TGR, $123.7 million used to repay borrowings under our secured revolving credit facility, $103.7 million of distributions paid to holders of common units, OpCo common units and Class B units, $4.9 million of restricted units repurchased for tax withholding and a $4.9 million payment of loan origination costs.

Cash flows provided by financing activities for the nine months ended September 30, 2022 consists of $227.6 million in proceeds from the initial public offering of TGR and $43.2 million of additional borrowings under our secured revolving credit facility, partially offset by $91.1 million of distributions paid to holders of common units, OpCo common units and Class B units, $56.4 million used to repay borrowings under out secured revolving credit facility, $3.3 million of restricted units repurchased for tax withholding, $2.7 million used to pay underwriting commissions related to the equity offering of TGR, $0.5 million paid in connection with the redemption of Class B units, $0.3 paid in connection with fees related to our 2021 equity offering and $0.4 million payment of loan origination costs.

Indebtedness

On June 13, 2023, we entered into an Amended and Restated Credit Agreement (the “A&R Credit Agreement”), which amended and restated our existing Credit Agreement, dated as of January 11, 2017 (as amended on July 12, 2018, December 8, 2020, June 7, 2022 and December 15, 2022). On July 24, 2023, we entered into Amendment No. 1 (the “First Amendment”) to the A&R Credit Agreement. The amendment amends the A&R Credit Agreement to, among other things, (i) decrease the frequency of and increase the threshold for excess cash determinations from $30.0 million to $50.0 million, and (ii) permit us to issue certain preferred equity interests.

The A&R Credit Agreement provides for, among other things, (i) a senior secured reserve-based revolving credit facility in an aggregate maximum principal amount of up to $750,000,000, with an initial borrowing base of $400.0 million and an initial aggregate elected commitments amount of up to $400.0 million, including a sub-facility for the issuance of letters of credit of up to $10,000,000, and (ii) an extension of the maturity date of the A&R Credit Agreement to June 7, 2027.

As of September 30, 2023, we had outstanding borrowings of $310.4 million under the secured revolving credit facility and $89.6 million of available capacity.

For additional information on our secured revolving credit facility, please read Note 9—Long-Term Debt to the unaudited interim consolidated financial statements included in this Quarterly Report.

Tax Matters

Even though we are organized as a limited partnership under state law, we are treated as a corporation for United States federal income tax purposes. Accordingly, we are subject to United States federal income tax at regular corporate rates on our net taxable income. We estimate that a portion of our quarterly distributions will constitute a non-taxable reduction to the tax basis of unitholders’ common units. The reduced tax basis will increase unitholders’ capital gain (or decrease unitholders’ capital loss) when unitholders sell their common units. We currently believe that the portion that constitutes dividends for U.S. federal income tax purposes will be considered qualified dividends, subject to holding period and certain other conditions, which are subject to a tax rate of 0%, 15% or 20% depending on the income level and tax filing status of a unitholder for 2023. Our estimates regarding treatment of our distributions are based on currently available information only and are subject to change, including with respect to prior quarters.

Distributions in excess of the amount taxable as dividend income will reduce a common unitholder's tax basis in its common units or produce capital gain to the extent they exceed a common unitholder's tax basis. Any reduced tax basis will increase a common unitholder's capital gain when it sells its common units. Our estimates are the result of certain non-cash expenses (principally depletion) substantially offsetting our taxable income and tax “earnings and profits.” Our estimates of the tax treatment of earnings and distributions are based upon assumptions regarding the capital structure and earnings of the Operating Company, our capital structure and the amount of the earnings of the Operating Company allocated to us. Many factors may impact these estimates, including changes in drilling and production activity, commodity prices, future acquisitions or changes in the business, economic, regulatory, legislative, competitive or political environment in which we operate. These estimates are based on current tax law and tax reporting positions that we have adopted and with which the Internal Revenue Service could disagree. These estimates are not fact and should not be relied upon as being necessarily indicative of future results, and no assurances can be made regarding these estimates. You are encouraged to consult with your tax advisor on this matter.

New and Revised Financial Accounting Standards

The effects of new accounting pronouncements are discussed in Note 2—Summary of Significant Accounting Policies to our unaudited interim consolidated financial statements included elsewhere in this Quarterly Report.

Critical Accounting Policies and Related Estimates

There have been no substantial changes to our critical accounting policies and related estimates from those previously disclosed in our 2022 Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

There have been no significant changes to our contractual obligations previously disclosed in our 2022 Form 10-K. As of September 30, 2023, we did not have any off-balance sheet arrangements. See Note 8—Leases to the unaudited interim consolidated financial statements for additional information regarding our operating leases.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to the oil, natural gas and NGL production of our operators. 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, natural gas and NGL production has been volatile and unpredictable for several years, and we expect commodity prices to be even more volatile in the future as a result of ongoing international supply and demand imbalances and limited international storage capacity. The prices that our operators receive for production depend on many factors outside of our or their control. To reduce the impact of fluctuations in oil and natural gas prices on our revenues, we entered into commodity derivative contracts to reduce our exposure to price volatility of oil and natural gas. The counterparties to the contracts are unrelated third parties.

Our commodity derivative contracts consist of fixed price swaps, under which we receive a fixed price for the contract and pay a floating market price to the counterparty over a specified period for a contracted volume.

Our oil fixed price swap transactions are settled based upon the average daily prices for the calendar month of the contract period, and our natural gas fixed price swap transactions are settled based upon the last day settlement of the first nearby month futures contract of the contract period. Settlement for oil derivative contracts occurs in the succeeding month and natural gas derivative contracts are settled in the production month.

Because we have not designated any of our derivative contracts as hedges for accounting purposes, changes in fair values of our derivative contracts will be recognized as gains and losses in current period earnings. As a result, our current period earnings may be significantly affected by changes in the fair value of our commodity derivative contracts. Changes in fair value are principally measured based on future prices as of period-end compared to the contract price. See Note 5—Derivatives to the unaudited interim consolidated financial statements in Item 1 of this Quarterly Report for additional information regarding our commodity derivatives.

Counterparty and Customer Credit Risk

Our derivative contracts expose us to credit risk in the event of nonperformance by counterparties. While we do not require our counterparties to our derivative contracts to post collateral, we do evaluate the credit standing of such counterparties as we deem appropriate. This evaluation includes reviewing a counterparty's credit rating and latest financial information. As of September 30, 2023, we had five counterparties to our derivative contracts, four of which are also lenders under our secured revolving credit facility.

As an owner of mineral and royalty interests, we have no control over the volumes or method of sale of oil, natural gas and NGLs produced and sold from the underlying properties. It is believed that the loss of any single purchaser would not have a material adverse effect on our results of operations.

Interest Rate Risk

We will have exposure to changes in interest rates on our indebtedness. As of September 30,2023, we had total borrowings outstanding under our secured revolving credit facility of $310.4 million. The impact of a 1% increase in the interest rate on this amount of debt could result in an increase in interest expense of approximately $3.1 million annually, assuming that our indebtedness remained constant throughout the year.

Inflation

Inflation in the United States did not have a material impact on results of operations for the period from January 1, 2022 through September 30, 2023. However, inflation in wages and other costs has the potential to adversely affect our results of operations, cash flows and financial position by increasing our overall cost structure. In addition, the existence of inflation in the economy has the potential to result in higher interest rates, which could result in higher borrowing costs, supply shortages, increased costs of labor and other similar effects.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) under the Securities Exchange Act of 1934, as amended (the “Exchange Act”), we have evaluated, under the supervision and with the participation of the management of our General Partner, including our General Partner’s principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as such terms are defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Quarterly Report. Our disclosure controls and procedures are designed to ensure that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to management, including our General Partner’s principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the SEC. Based upon that evaluation, our General Partner’s management, including its principal executive officer and principal financial officer concluded that as of September 30, 2023, our disclosure controls and procedures were effective in ensuring that all information required to be disclosed by us in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC rules and forms, and that such information is accumulated and communicated to our General Partner’s management, including its principal executive officer and principal financial officer, in a manner that allows timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

There have not been any changes in our internal control over financial reporting that occurred during the quarter ended September 30, 2023 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings

For a description of the Partnership’s legal proceedings, see Note 17—Commitments and Contingencies to the unaudited interim consolidated financial statements included in Part I of this Quarterly Report and incorporated by reference herein.

Item 1A. Risk Factors

In addition to the risks and uncertainties discussed in this Quarterly Report, included in Part I, Item 2: Management's Discussion and Analysis of Financial Condition and Results of Operations and the risk factors listed below, you should carefully consider the risks set out under the heading "Risk Factors" in Part I, Item 1A. Risk Factors in our 2022 Form 10-K. These risk factors could materially affect our business, financial condition and results of operations. The unprecedented nature of the current pandemic and the volatility in the worldwide economy and oil and gas industry may make it more difficult to identify all the risks to our business, results of operations and financial condition and the ultimate impact of identified risks. Further, these risks are not the only risks that we face. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial may materially adversely affect our business, financial condition or results of operations.

Our Series A preferred units have rights, preferences and privileges that are not held by, and are preferential to the rights of, holders of our common units.

On September 13, 2023, we issued 325,000 preferred units representing limited partner interests in the Partnership. The Series A preferred units rank senior to our common units with respect to distribution rights and rights upon liquidation. These preferences could adversely affect the market price for our common units or could make it more difficult for us to sell our common units in the future.

Until the conversion of the Series A preferred units into common units or their redemption, holders of the Series A preferred units are entitled to receive cumulative quarterly distributions equal to 6.0% per annum plus accrued and unpaid distributions. We have the right, in any four non-consecutive quarters, to elect not to pay such quarterly distribution in cash and instead have the unpaid distribution amount added to the liquidation preference at the rate of 10.0% per annum. If we make such an election in consecutive quarters or if we fail to pay in full, in cash and when due, any distribution owed to the Series A preferred units or otherwise materially breach our obligations to the holders of the Series A preferred units, the distribution rate will increase to 20.0% per annum until the accumulated distributions are paid in full in cash, or any such material breach is cured, as applicable. Each holder of Series A preferred units has the right to share in any special distributions by us of cash, securities or other property pro rata with the common units on an as-converted basis, subject to customary adjustments. We cannot declare or make any distributions, redemptions, or repurchases on any junior securities, including any of our common units, prior to paying the quarterly distribution payable to the Series A preferred units, including any previously accrued and unpaid distributions. Our obligation to pay distributions on our Series A preferred units could impact our liquidity and reduce the amount of cash flow available for working capital, capital expenditures, growth opportunities, acquisitions and other general partnership purposes. Our obligations to the holders of the Series A preferred units could also limit our ability to obtain additional financing or increase our borrowing costs, which could have an adverse effect on our financial condition.

The terms of our Series A preferred units contain covenants that may limit our business flexibility.

The terms of our Series A preferred units contain covenants preventing us from taking certain actions without the approval of the holders of $66^2/_3$% of the outstanding Series A preferred units, voting separately as a class. The need to obtain the approval of holders of the Series A preferred units before taking these actions could impede our ability to take certain actions that management or our board of directors may consider to be in the best interests of our common unitholders.

The affirmative vote of $66^2/_3$% of the outstanding Series A preferred units, voting separately as a class, will be necessary to amend our partnership agreement in any manner that is materially adverse to any of the rights, preferences and privileges of the Series A preferred units. The affirmative vote of $66^2/_3$% of the outstanding Series A preferred units voting separately as a class, will be necessary to, among other things, (i) issue, authorize or create any additional Series A preferred units or any class or series of partnership interests (or any obligation or security convertible into, exchangeable for or evidencing the right to purchase any class or series of partnership interests) that, with respect to distributions on such partnership interests or distributions in respect of such partnership interests upon our liquidation, dissolution and winding up, ranks equal to or senior to the Series A preferred units or (ii) under certain circumstances, incur certain indebtedness for borrowed money.

Item 5. Other Information

During the period covered by this report, none of the Partnership's directors or executive officers has adopted or terminated a Rule 10b5-1 trading arrangement or a non-Rule 10b5-1 trading arrangement (each as defined in Item 408 of Regulation S-K under the Securities Exchange Act of 1934, as amended).

Item 6. Exhibits

Exhibit Number		Description
3.1	—	Certificate of Limited Partnership of Kimbell Royalty Partners, LP (incorporated by reference to Exhibit 3.1 to Kimbell Royalty Partners, LP's Registration Statement on Form S-1 (File No. 333-215458) filed on January 6, 2017)
3.2	—	Fifth Amended and Restated Agreement of Limited Partnership of Kimbell Royalty Partners, LP, dated as of September 13, 2023 (incorporated by reference to Exhibit 3.1 to Kimbell Royalty Partners, LP's Current Report on Form 8-K filed September 13, 2023)
3.3	—	Certificate of Formation of Kimbell Royalty GP, LLC (incorporated by reference to Exhibit 3.3 to Kimbell Royalty Partners, LP's Registration Statement on Form S-1 (File No. 333-215458) filed on January 6, 2017)
3.4	—	Third Amended and Restated Limited Liability Company Agreement of Kimbell Royalty Operating, LLC, dated as of September 13, 2023 (incorporated by reference to Exhibit 3.2 to Kimbell Royalty Partners, LP's Current Report on Form 8-K filed on September 13, 2023)
4.1	—	Registration Rights Agreement, dated as of May 17, 2023, by and among between Kimbell Royalty Partners, LP and MB Minerals, L.P. (incorporated by reference to Exhibit 4.1 to Kimbell Royalty Partners, LP Current Report on Form 8-K filed on May 18, 2023)
4.2	—	Registration Rights Agreement, dated as of September 13, 2023, by and among Kimbell Royalty Partners, LP and the parties listed on the signature page thereof (incorporated by reference to Exhibit 4.1 to Kimbell Royalty Partners, LP's Current Report on Form 8-K filed on September 13, 2023)
10.1	—	Amended and Restated Credit Agreement, dated as of June 13, 2023, by and among Kimbell Royalty Partners, LP, each of the guarantors party thereto, the several lenders from time to time parties thereto and Citibank, N.A., as administrative agent (incorporated by reference to Exhibit 10.1 to Kimbell Royalty Partners, LP's Current Report on Form 8-K filed on June 20, 2023)
10.2	—	Amendment No. 1 to Amended and Restated Credit Agreement, dated as of July 24, 2023, by and among Kimbell Royalty Partners, LP, each of the guarantors party thereto, the several lenders from time to time parties thereto and Citibank, N.A., as administrative agent (incorporated by reference to Exhibit 10.1 to Kimbell Royalty Partners, LP's Current Report on Form 8-K filed on July 28, 2023)
10.3	—	Purchase and Sale Agreement, dated as of April 11, 2023, by and among MB Minerals, L.P., Kimbell Royalty Partners, LP and Kimbell Royalty Operating, LLC (incorporated by reference to Exhibit 10.1 to Kimbell Royalty Partners, LP's Current Report on Form 8-K filed on April 12, 2023)
10.4	—	Securities Purchase Agreement, dated as of August 2, 2023, by and between LongPoint Minerals II, LLC and Kimbell Royalty Partners, LP (incorporated by reference to Exhibit 10.1 to Kimbell Royalty Partners, LP's Current Report on Form 8-K filed on August 2, 2023)
10.5	—	Preferred Units Purchase Agreement, dated as of August 2, 2023, by and among Kimbell Royalty Partners, LP and the several purchasers party thereto (incorporated by reference to Exhibit 10.2 to Kimbell Royalty Partners, LP's Current Report on Form 8-K filed on August 2, 2023)
10.6	—	Board Representation and Observation Agreement, dated as of September 13, 2023, by and among Kimbell Royalty Partners, LP, Kimbell GP Holdings, LLC, Apollo Accord+ Aggregator A, L.P., Apollo Accord V Aggregator A, L.P., Apollo Defined Return Aggregator A, L.P., Apollo Calliope Fund, L.P., Apollo Excelsior, L.P., Apollo Credit Strategies Master Fund Ltd., Apollo Atlas Master Fund, LLC, Apollo Union Street SPV, L.P., Host Plus PTY Limited - Accord, Apollo Delphi Fund, L.P., Apollo Royalties Fund I, L.P., AHVF (AIV), L.P., AHVF Intermediate Holdings, L.P., AHVF TE/892/QFPF (AIV), L.P. and ACMP Holdings, LLC (incorporated by reference to Exhibit 10.1 to Kimbell Royalty Partners, LP's Current Report on Form 8-K filed on September 13, 2023)

10.7	— Transition Services Agreement, by and between Kimbell Royalty Operating, LLC and FourPoint Energy, LLC (incorporated by reference to Exhibit 10.2 to Kimbell Royalty Partners, LP's Current Report on Form 8-K filed on September 13, 2023)
31.1*	— Certification of Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) under the Securities Exchange Act of 1934
31.2*	— Certification of Chief Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) under the Securities Exchange Act of 1934
32.1**	— Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350
32.2**	— Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350
101.INS*	— Inline XBRL Instance Document —the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document
101.SCH*	— Inline XBRL Taxonomy Extension Schema Document
101.CAL*	— Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	— Inline XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	— Inline XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	— Inline XBRL Taxonomy Extension Presentation Linkbase Document
104*	— Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

* —filed herewith
** —furnished herewith

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Kimbell Royalty Partners, LP

By: Kimbell Royalty GP, LLC
its general partner

Date: November 2, 2023

By: /s/ Robert D. Ravnaas
Name: Robert D. Ravnaas
Title: *Chief Executive Officer and Chairman*
Principal Executive Officer

Date: November 2, 2023

By: /s/ R. Davis Ravnaas
Name: R. Davis Ravnaas
Title: *President and Chief Financial Officer*
Principal Financial Officer

Exhibit 31.1

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Robert D. Ravnaas, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Kimbell Royalty Partners, LP;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 2, 2023

/s/ Robert D. Ravnaas
Chief Executive Officer and Chairman of the Board of Directors of Kimbell Royalty GP, LLC, the general partner of Kimbell Royalty Partners, LP
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, R. Davis Ravnaas, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Kimbell Royalty Partners, LP;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 2, 2023

/s/ R. Davis Ravnaas
President and Chief Financial Officer of Kimbell Royalty GP, LLC, the general partner of Kimbell Royalty Partners, LP
(Principal Financial Officer)

Exhibit 32.1

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Kimbell Royalty Partners, LP (the “Partnership”) on Form 10-Q for the fiscal quarter ended September 30, 2023, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Robert D. Ravnaas, Chief Executive Officer and Chairman of the Board of Directors of Kimbell Royalty GP, LLC, the general partner of the Partnership, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: November 2, 2023

/s/ Robert D. Ravnaas
Chief Executive Officer and Chairman of the Board of Directors of Kimbell Royalty GP, LLC, the general partner of Kimbell Royalty Partners, LP
(Principal Executive Officer)

Exhibit 32.2

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Kimbell Royalty Partners, LP (the “Partnership”) on Form 10-Q for the fiscal quarter ended September 30, 2023, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, R. Davis Ravnaas, President and Chief Financial Officer of Kimbell Royalty GP, LLC, the general partner of the Partnership, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: November 2, 2023

/s/ R. Davis Ravnaas
President and Chief Financial Officer of Kimbell Royalty GP, LLC, the general partner of Kimbell Royalty Partners, LP
(Principal Financial Officer)