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

FORM 10-QT

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

For the quarterly period ended

OR

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

For the transition period from October 1, 2021 to December 31, 2021

Commission file number 001-15555

Riley Exploration Permian, Inc.

(Exact name of registrant as specified in its charter)

Delaware	**87-0267438**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
29 E. Reno Avenue, Suite 500 Oklahoma City, Oklahoma	**73104**
(Address of Principal Executive Offices)	(Zip Code)

Registrant's telephone number, including area code: **(405) 415-8699**
Former Fiscal Year: September 30

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common stock, par value $0.001	REPX	NYSE American

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 and posted on its corporate web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer	☐	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 Act). Yes ☐ No ☒

The total number of shares of common stock, par value $0.001 per share, outstanding as of September 16, 2022 was 19,866,637.

RILEY EXPLORATION PERMIAN, INC.
TRANSITION REPORT ON FORM 10-QT FOR THE QUARTER ENDED DECEMBER 31, 2021
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Introductory Note to this Transition Report

On August 16, 2022, the Company's Board of Directors (the "Board") acting by written consent resolved to amend and restate the Company's Second Amended and Restated Bylaws to change the Company's fiscal year period from October 1st through September 30th each year to January 1st through December 31st each year commencing with the 2022 calendar year (the "Bylaws Restatement"). On August 19, 2022, the holders of approximately 75% of our outstanding Common Stock acting by written consent approved Bylaws Restatement and adopted the Third Amended and Restated Bylaws, which are included hereto as Exhibit 3.3. In accordance with Rule 14c-2 under the Exchange Act, the aforementioned actions taken by written consent became effective on September 23, 2022. As a result, the Company's 2022 fiscal year will now be the period from January 1, 2022 to December 31, 2022.

Unless the context requires otherwise or unless otherwise noted, all references in this Transition Report on Form 10-QT to the "Company," "Riley Permian," "REPX," "we," "us," or "our" are to Riley Exploration Permian, Inc., together with its consolidated subsidiaries.

DEFINITIONS

The following are abbreviations and definitions of certain terms used within this Transition Report on Form 10-QT:

Measurements.	
Bbl	One barrel or 42 U.S. gallons liquid volume of oil or other liquid hydrocarbons.
Boe	One stock tank barrel equivalent of oil, calculated by converting gas volumes to equivalent oil barrels at a ratio of 6 thousand cubic feet of gas to 1 barrel of oil and by converting NGL volumes to equivalent oil barrels at a ratio of 1 barrel of NGL to 1 barrel of oil.
Boe/d	Stock tank barrel equivalent of oil per day.
Btu	British thermal unit. One British thermal unit is the amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit.
MBbl	One thousand barrels of oil or other liquid hydrocarbons.
MBoe	One thousand Boe.
MBoe/d	One thousand Boe per day.
Mcf	One thousand cubic feet of gas.
MMBtu	One million British thermal units.
Abbreviations.	
ARO	Asset Retirement Obligation.
ASC	Accounting Standards Codification.
ASU	Accounting Standards Update.
CO_2	Carbon Dioxide.
EOR	Enhanced Oil Recovery.
FASB	Financial Accounting Standards Board.
GHG	Greenhouse Gas.
LIBOR	London Interbank Offered Rate.
NGL	Natural gas liquids.
NYSE	New York Stock Exchange.
Oil	Crude oil and condensate.
SEC	Securities and Exchange Commission.
SOFR	Secured Overnight Financing Rate.
U.S. GAAP	Accounting principles generally accepted in the United States of America.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Various statements contained in this Transition Report on Form 10-QT ("Transition Report") are "forward-looking statements" as defined by the SEC. All statements, other than statements of historical fact, contained in this Transition Report that include information concerning our possible or assumed future results of operations, business strategies, need for financing, competitive position and potential growth opportunities represent management's beliefs and assumptions based on currently available information and they do not consider the effects of future legislation or regulations. Forward-looking statements include all statements that are not historical facts and can be identified by the use of forward-looking terminology such as the words “believes,” “intends,” “may,” “should,” “anticipates,” “expects,” “could,” “plans,” “estimates,” “projects,” “targets” or comparable terminology or by discussions of strategy or trends. Such statements by their nature involve risks and uncertainties that could significantly affect expected results, and actual future results could differ materially from those described in such forward-looking statements.

Among the factors that could cause actual future results to differ materially are the risks and uncertainties discussed under “Item 1A Risk Factors” in this Transition Report and in our Annual Report on Form 10-K for the year ended September 30, 2021. We continue to face many risks and uncertainties including, but not limited to:

- the volatility of oil, natural gas and NGL prices;
- the scope, duration, and reoccurrence of any epidemics or pandemics (including, specifically, the coronavirus disease 2019 ("COVID-19") pandemic and any related variants), including reactive or proactive measures taken by governments, regulatory agencies and businesses related to the pandemic, and the effects of COVID-19 on the oil and natural gas industry, pricing and demand for oil and natural gas and supply chain logistics;
- regional supply and demand factors, any delays, curtailment delays or interruptions of production, and any governmental order, rule or regulation that may impose production limits;
- cost and availability of gathering, pipeline, refining, transportation and other midstream and downstream activities;
- severe weather and other risks that lead to a lack of any available markets;
- our ability to successfully complete mergers, acquisitions and divestitures;
- the risk that the Company's EOR project may not perform as expected or produce the anticipated benefits;
- risks relating to our operations, including development drilling and testing results and performance of acquired properties and newly drilled wells;
- any reduction in our borrowing base on our revolving credit facility from time to time and our ability to repay any excess borrowings as a result of such reduction;
- the impact of our derivative strategy and the results of future settlement;
- our ability to comply with the financial covenants contained in our revolving credit facility;
- changes in general economic, business or industry conditions, including changes in inflation rates, interest rates, and foreign currency exchange rates;
- conditions in the capital, financial and credit markets and our ability to obtain capital needed for development and exploration operations on favorable terms or at all;
- the loss of certain tax deductions;
- risks associated with executing our business strategy, including any changes in our strategy;
- inability to prove up undeveloped acreage and maintain production on leases;
- risks associated with concentration of operations in one major geographic area;
- legislative or regulatory changes, including initiatives related to hydraulic fracturing, emissions, and disposal of produced water, which may be negatively impacted by regulation or legislation;
- the ability to receive drilling and other permits or approvals and rights-of-way in a timely manner (or at all), which may be restricted by governmental regulation and legislation;
- restrictions on the use of water, including limits on the use of produced water and a moratorium on new produced water well permits recently imposed by the RRC in an effort to control induced seismicity in the Permian Basin;
- risks related to litigation;
- actions taken by the members of OPEC and Russia affecting the production and pricing of oil, as well as other domestic and global political, economic, or diplomatic developments; and
- cybersecurity threats, technology system failures and data security issues.

All forward-looking statements speak only as of the date of this Transition Report. You should not place undue reliance on these forward-looking statements. These forward-looking statements are subject to a number of risks, uncertainties and assumptions. Moreover, we operate in a very competitive and rapidly changing environment. New risks emerge from time to time. It is not possible for our management to predict all risks, nor can we assess the impact of all factors on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements we may make. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this Transition Report are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved or occur, and actual results could differ materially and adversely from those anticipated or implied by the forward-looking statements.

Part I. FINANCIAL INFORMATION

Item 1. Financial Statements

Report of Independent Registered Public Accounting Firm

Shareholders and Board of Directors
Riley Exploration Permian, Inc.
Oklahoma City, Oklahoma

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Riley Exploration Permian, Inc. (the “Company”) as of December 31, 2021 and September 30, 2021, the related consolidated statements of operations, changes in members’/shareholders’ equity, and cash flows for the three months ended December 31, 2021, and the related notes (collectively referred to as the “consolidated financial statements”). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2021 and September 30, 2021, and the results of its operations and its cash flows for the three months ended December 31, 2021**,** in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (“PCAOB”) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company’s internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates to accounts or disclosures that are material to the consolidated financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of a critical audit matter does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Estimation of Oil and Natural Gas Reserves and Effect on Depreciation, Depletion and Amortization (“DD&A”) Expense Related to Proved Oil and Natural Gas Properties

The Company’s oil and natural gas properties, net balance as of December 31, 2021 was $359.1 million, which includes proved oil and natural gas properties of $421.8 million and accumulated DD&A of $95.0 million. DD&A expense was $6.7 million for the three months ended December 31, 2021. As described in Note 3 - Summary of Significant Accounting Policies to the consolidated financial statements, the Company accounts for its oil and natural gas activities using the successful efforts method of accounting which involves management’s use of internal and independent petroleum engineers to make estimates of proved oil and natural gas reserves necessary to record DD&A expense. To estimate the proved oil and natural gas reserves, management and their internal and independent petroleum engineers make significant estimates and assumptions including forecasting of future production volumes and lease operating expenses of proved oil and natural gas properties.

We have identified the estimation of future production volumes and lease operating expenses used to estimate proved oil and natural gas reserves and the associated effect on DD&A expense related to proved oil and natural gas properties as a critical audit matter. Estimating future production volumes and lease operating expenses involves a high degree of subjectivity from management and their internal and independent petroleum engineers. Changes in these estimates and assumptions could have a significant effect on the measurement of DD&A expense. Auditing these estimates and assumptions required subjective and complex auditor judgement.

The primary procedures we performed to address this critical audit matter included:

- Evaluating the professional qualifications of the internal and independent petroleum engineers, including their relationship to the Company, and making inquiries regarding the process and judgments used in estimating the Company’s proved oil and natural gas reserves.

- Comparing estimates of future production volumes, production decline analyses, and lease operating expenses against historical results of production volumes, production decline analyses, and lease operating expenses on a summary basis for all wells and a detailed basis for certain wells.

- Performing a retrospective review over management estimates of future production volumes made in prior periods as compared to actual results.

/s/ BDO USA, LLP

We have served as the Company's auditor since 2016.

Houston, Texas
September 23, 2022

RILEY EXPLORATION PERMIAN, INC.
CONSOLIDATED BALANCE SHEETS

	December 31, 2021	September 30, 2021
	(In thousands, except share amounts)	
Assets		
Current Assets:		
Cash and cash equivalents	$ 8,317	$ 17,067
Accounts receivable	18,002	17,473
Accounts receivable - related parties	—	456
Prepaid expenses and other current assets	4,902	1,730
Current derivative assets	83	—
Total current assets	**31,304**	**36,726**
Oil and natural gas properties, net (successful efforts)	359,131	345,797
Other property and equipment, net	3,174	3,183
Non-current derivative assets	267	106
Other non-current assets, net	2,293	2,419
Total Assets	**$ 396,169**	**$ 388,231**
Liabilities and Shareholders' Equity		
Current Liabilities:		
Accounts payable	$ 7,737	$ 12,234
Accounts payable - related parties	164	—
Accrued liabilities	12,874	19,355
Revenue payable	11,370	9,008
Current derivative liabilities	30,984	42,144
Other current liabilities	947	874
Total Current Liabilities	**64,076**	**83,615**
Non-current derivative liabilities	9,515	8,932
Asset retirement obligations	2,261	2,306
Revolving credit facility	65,000	60,000
Deferred tax liabilities	17,384	11,628
Other non-current liabilities	95	60
Total Liabilities	**158,331**	**166,541**
Commitments and Contingencies (Note 14)		
Shareholders' Equity:		
Preferred stock, $0.0001 par value, 25,000,000 shares authorized; 0 shares issued and outstanding	—	—
Common stock, $0.001 par value, 240,000,000 shares authorized; 19,836,885 and 19,672,050 shares issued and outstanding at December 31, 2021 and September 30, 2021, respectively	20	20
Additional paid-in capital	271,737	270,837
Accumulated deficit	(33,919)	(49,167)
Total Shareholders' Equity	**237,838**	**221,690**
Total Liabilities and Shareholders' Equity	**$ 396,169**	**$ 388,231**

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

RILEY EXPLORATION PERMIAN, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended December 31, 2021	Three Months Ended December 31, 2020
		(Unaudited)
	(In thousands, except per share/unit amounts)	
Revenues:		
Oil and natural gas sales, net	$ 56,650	$ 22,414
Contract services - related parties	600	600
Total Revenues	**57,250**	**23,014**
Costs and Expenses:		
Lease operating expenses	7,419	4,568
Production and ad valorem taxes	3,005	1,289
Exploration costs	611	424
Depletion, depreciation, amortization and accretion	6,867	5,990
General and administrative:		
Administrative costs	3,633	2,445
Unit-based compensation expense	—	413
Share-based compensation expense	951	—
Cost of contract services - related parties	150	148
Transaction costs	1,258	1,049
Total Costs and Expenses	**23,894**	**16,326**
Income From Operations	**33,356**	**6,688**
Other Income (Expense):		
Interest expense	(896)	(1,235)
Loss on derivatives	(5,193)	(13,909)
Total Other Income (Expense)	**(6,089)**	**(15,144)**
Net Income (Loss) Before Income Taxes	**27,267**	**(8,456)**
Income tax benefit (expense)	(5,869)	515
Net Income (Loss)	**21,398**	**(7,941)**
Dividends on preferred units	—	(917)
Net Income (Loss) Attributable to Common Shareholders/Unitholders	**$ 21,398**	**$ (8,858)**
Net Income (Loss) per Share/Unit:		
Basic	$ 1.10	$ (0.71)
Diluted	$ 1.09	$ (0.71)
Weighted Average Common Shares/Units Outstanding:		
Basic	19,470	12,469
Diluted	19,569	12,469

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

RILEY EXPLORATION PERMIAN, INC.
CONSOLIDATED STATEMENTS OF CHANGES IN MEMBERS'/SHAREHOLDERS' EQUITY
(In thousands)

Three Months Ended December 31, 2021

	Members' Equity		Shareholders' Equity				
			Common Stock				
	Units Outstanding	Amount	Shares	Amount	Additional Paid-in Capital	Accumulated Deficit	Total Shareholders' Equity
Balance, September 30, 2021	—	$ —	19,672	$ 20	$ 270,837	$ (49,167)	$ 221,690
Share-based compensation expense	—	—	—	—	919	—	919
Repurchased shares for tax withholding	—	—	(10)	—	(19)	—	(19)
Issuance of common shares under long-term incentive plan	—	—	175	—	—	—	—
Dividends declared	—	—	—	—	—	(6,150)	(6,150)
Net income	—	—	—	—	—	21,398	21,398
Balance, December 31, 2021	—	$ —	19,837	$ 20	$ 271,737	$ (33,919)	$ 237,838

Three Months Ended December 31, 2020

	Members' Equity		Shareholders' Equity				
			Common Stock				
	Units Outstanding	Amount	Shares	Amount	Additional Paid-in Capital	Accumulated Deficit	Total Shareholders' Equity
				(Unaudited)			
Balance, September 30, 2020	1,555	$ 166,617	—	$ —	$ —	$ —	$ —
Issuance of common units under long-term incentive plan	13	—	—	—	—	—	—
Dividends on preferred units	—	(917)	—	—	—	—	—
Dividends on common units	—	(3,801)	—	—	—	—	—
Unit-based compensation expense	—	413	—	—	—	—	—
Net loss	—	(7,941)	—	—	—	—	—
Balance, December 31, 2020	1,568	$ 154,371	—	$ —	$ —	$ —	$ —

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

RILEY EXPLORATION PERMIAN, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended December 31,	
	2021	2020
		(Unaudited)
	(In thousands)	
Cash Flows from Operating Activities:		
Net income (loss)	$ 21,398	$ (7,941)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Oil and gas lease expirations	588	424
Depletion, depreciation, amortization and accretion	6,867	5,990
Loss on derivatives	5,193	13,909
Settlements on derivative contracts	(16,014)	5,173
Amortization of deferred financing costs	282	155
Unit-based compensation expense	—	413
Share-based compensation expense	951	—
Deferred income tax expense (benefit)	5,756	(515)
Changes in operating assets and liabilities:		
Accounts receivable	(529)	(397)
Accounts receivable – related parties	456	(258)
Prepaid expenses and other current assets	(3,172)	(39)
Other non-current assets	—	1
Accounts payable and accrued liabilities	(2,625)	(385)
Accounts payable - related parties	164	—
Income taxes payable	113	—
Revenue payable	2,362	95
Advances from joint interest owners	—	(2)
Advances from related parties	—	570
Other liabilities	(63)	—
Net Cash Provided By Operating Activities	**21,727**	**17,193**
Cash Flows from Investing Activities:		
Additions to oil and natural gas properties	(29,011)	(9,389)
Additions to other property and equipment	(117)	(318)
Net Cash Used In Investing Activities	**(29,128)**	**(9,707)**
Cash Flows from Financing Activities:		
Deferred financing costs	(274)	(52)
Proceeds from revolving credit facility	5,000	2,000
Repayment under revolving credit facility	—	(5,500)
Payment of common share/unit dividends	(6,056)	(3,717)
Common stock repurchased for tax withholding	(19)	—
Net Cash Used in Financing Activities	**(1,349)**	**(7,269)**
Net Increase (Decrease) in Cash and Cash Equivalents	**(8,750)**	**217**
Cash and Cash Equivalents, Beginning of Period	**17,067**	**1,660**
Cash and Cash Equivalents, End of Period	**$ 8,317**	**$ 1,877**

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

RILEY EXPLORATION PERMIAN, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS - (Continued)

	Three Months Ended December 31,	
	2021	2020
		(Unaudited)
	(In thousands)	
Supplemental Disclosure of Cash Flow Information		
Cash Paid For:		
Interest	$ 495	$ 850
Non-cash Investing and Financing Activities - Continuing Operations:		
Changes in capital expenditures in accounts payable and accrued liabilities	$ (8,443)	$ (680)
Preferred unit dividends paid in kind	$ —	$ 904
Preferred unit dividends	$ —	$ 917

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

(1) Nature of Business

Organization

Riley Permian is a growth-oriented, independent oil and natural gas company focused on the acquisition, exploration, development and production of oil, natural gas and NGLs in Texas and New Mexico. Our activities primarily include the horizontal development of the San Andres formation, a shelf margin deposit on the Northwest Shelf of the Permian Basin. Our acreage is primarily located on large, contiguous blocks in Yoakum County, Texas.

On February 26, 2021 (the “Closing Date”), Riley Permian (f/k/a Tengasco, Inc. (“Tengasco”)), consummated a merger, dated as of October 21, 2020, by and among Tengasco, Antman Sub, LLC, a newly formed Delaware limited liability company and wholly-owned subsidiary of Tengasco (“Merger Sub”), and Riley Exploration – Permian, LLC (“REP LLC”). Merger Sub merged with and into REP LLC, with REP LLC as the surviving company and as a wholly-owned subsidiary of Tengasco (collectively, with the other transactions described in the Merger Agreement, the “Merger”). On the Closing Date, the Registrant changed its name from Tengasco, Inc. to Riley Exploration Permian, Inc.

Commodity Environment

During 2020, a novel strain of coronavirus, SARS-CoV-2, causing a disease referred to as COVID-19, spread quickly across the globe. Federal, state and local governments mobilized to implement containment mechanisms and minimize impacts to their populations and economies. Various containment measures, which included the quarantining of cities, regions and countries, resulted in a severe drop in general economic activity and a resulting decrease in energy demand.

As oil and natural gas operations are considered essential in the State of Texas and New Mexico, the Company did not have any significant disruptions in operations.

This outbreak and the related responses of governmental authorities and others to limit the spread of the virus significantly reduced global economic activity, resulting in a significant decline in the demand for oil and other commodities. These factors caused a swift and material deterioration in commodity prices for a majority of 2020, which significantly impacted our revenues for 2020 and, to a lesser degree, 2021.

(2) Basis of Presentation

On August 16, 2022, the Company's Board of Directors (the "Board") acting by written consent resolved to amend and restate the Company's Second Amended and Restated Bylaws to change the Company's fiscal year period from October 1st through September 30th each year to January 1st through December 31st each year commencing with the 2022 calendar year (the "Bylaws Restatement"). On August 19, 2022, the holders of approximately 75% of our outstanding Common Stock acting by written consent approved Bylaws Restatement and adopted the Third Amended and Restated Bylaws, which are included hereto as Exhibit 3.3. In accordance with Rule 14c-2 under the Exchange Act, the aforementioned actions taken by written consent became effective on September 23, 2022. As a result, the Company's 2022 fiscal year will now be the period from January 1, 2022 to December 31, 2022.

As a result of the change in fiscal year, this document reflects the Company's Transition Report on Form 10-QT for the transition period from October 1, 2021 through December 31, 2021. The Company's next fiscal year will run from January 1, 2022 through December 31, 2022 (fiscal 2022).

The accompanying balance sheet as of September 30, 2021 was derived from the Company's audited financial statements included in Form 10-K filed with the SEC on December 14, 2021. The accompanying consolidated statement of operations, consolidated statement of changes in members'/stockholders' equity, consolidated statement of cash flows and footnote disclosures for the three months ended December 31, 2020 are unaudited. The unaudited consolidated financial statements for the three months ended December 31, 2020 have been prepared on the same basis as the annual audited financial statements and, in the opinion of management, contain all adjustments necessary for fair presentation of the results of operations for the periods presented, except as disclosed herein.

These consolidated financial statements as of December 31, 2021 and for the three months ended December 31, 2021 include the accounts of Riley Permian and its wholly-owned subsidiaries REP LLC, Riley Permian Operating Company, LLC ("RPOC"), Tengasco Pipeline Corporation, Tennessee Land & Mineral Corporation, and Manufactured Methane Corporation, and have been prepared in accordance with U.S. GAAP. All intercompany balances and transactions have been eliminated upon consolidation. The Merger was accounted for as a reverse merger and, as such, the historical operations of REP LLC are deemed to be those of the Company. Thus, the consolidated financial statements included in this report reflect (i) the historical operating results of REP LLC prior to the Merger; (ii) the consolidated results of the Company following the Merger; (iii) the assets and liabilities of REP LLC at their historical cost; and (iv) the Company's equity and earnings per share for all periods presented.

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

(3) Summary of Significant Accounting Policies

Significant Estimates

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. These estimates and assumptions may also affect disclosure of contingent assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period.

The Company evaluates these estimates on an ongoing basis, using historical experience, consultation with experts and other methods the Company considers reasonable in the particular circumstances. Actual results may differ significantly from the Company's estimates. Any effects on the Company's business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known. Significant items subject to such estimates and assumptions include, but are not limited to, estimates of proved oil and natural gas reserves and related present value estimates of future net cash flows therefrom, the carrying value of oil and natural gas properties, accounts receivable, accrued capital expenditures and operating expenses, ARO, the fair value determination of acquired assets and assumed liabilities, certain tax accruals and the fair value of derivatives.

Cash and Cash Equivalents

The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents. The Company maintains cash at financial institutions which may at times exceed federally insured amounts. The Company has not experienced any losses in such accounts and believes it is not exposed to any significant credit risk on its cash and cash equivalents.

Accounts Receivable

Our receivables arise primarily from the sale of oil, natural gas and NGLs and joint interest owner receivables for properties in which we serve as the operator. Accounts receivable are stated at amounts due, net of an allowance for credit losses, if necessary.

Accounts receivable from oil, natural gas and NGL sales are generally due within 30 to 60 days after the last day of each production month. No interest is charged on past-due balances. Payments made on all accounts receivable are applied to the earliest unpaid items.

To the extent actual volumes and prices of oil, natural gas and NGLs are unavailable for a given reporting period because of timing or information not received from third parties, the expected sales volume and prices for these properties are estimated and recorded within accounts receivable in the accompanying consolidated balance sheets. Oil is priced based upon prevailing prices published by purchasers with certain adjustments related to oil quality and physical location. Natural gas pricing provisions are tied to a market index, with certain adjustments based on, among other factors, quality and heat content of natural gas, and prevailing supply and demand conditions. NGLs are priced based upon a market index with certain adjustments for transportation and fractionation. These market indices are determined on a monthly basis.

On October 1, 2020, the Company adopted ASU 2016-13, Financial Instruments – Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments using a modified retrospective approach. This ASU replaced the incurred impairment model with an expected credit loss model for financial instruments, including accounts receivable. The ASU requires the Company to consider forward-looking information to estimate expected credit losses, resulting in earlier recognition of losses for receivables that are current or not yet due, which were not considered under previous accounting guidance. As a result of adoption, the Company establishes allowances for credit losses equal to the estimable portions of accounts receivable for which failure to collect is expected to occur, if applicable. The Company estimates uncollectible amounts based on the length of time that the accounts receivable has been outstanding, historical collection experience and current and future economic and market conditions, if failure to collect is expected to occur. Allowances for credit losses are recorded as reductions to the carrying values of the accounts receivables included in the Company's consolidated balance sheets and are recorded in Administrative costs in the consolidated statements of operations if failure to collect an estimable portion is determined to be probable. The Company had no allowance for credit losses at December 31, 2021 and September 30, 2021.

Accounts receivable is summarized below:

	December 31, 2021	September 30, 2021
	(In thousands)	
Oil, natural gas and NGL sales	$ 17,562	$ 17,008
Joint interest accounts receivable	409	413
Realized derivative receivable	—	42
Other accounts receivable	31	10
Total accounts receivable	$ 18,002	$ 17,473

Proved Oil and Natural Gas Properties

The Company uses the successful efforts method of accounting for its oil and natural gas producing activities. Under this method, all property acquisition costs and costs of development wells are capitalized as incurred. The costs of development wells are capitalized whether producing or non-producing. Costs to drill exploratory wells are capitalized pending the determination of whether proved reserves are found. If an exploratory well is determined to be unsuccessful, the costs of drilling the unsuccessful exploratory well are charged to exploration costs.

Geological and geophysical costs, including seismic studies, are charged to exploration costs as incurred. Expenditures incurred to operate and for maintenance, repairs and minor renewals necessary to maintain our oil and natural gas properties in operating condition are charged to lease operating expenses as incurred.

Capitalized costs of proved oil and natural gas properties are amortized using the units-of-production method based on production and estimates of proved reserve quantities. Leasehold acquisition costs of proved properties are depleted over total estimated proved reserves, and capitalized development costs of wells and related equipment and facilities are depleted over-estimated proved developed reserves.

On the sale or retirement of a complete unit of a proved property or field, the cost and related accumulated depletion, depreciation and amortization are eliminated from the oil and natural gas property accounts, and the resulting gain or loss is recognized. On the sale of a partial unit of proved property, the unamortized cost of the property is apportioned to the interest sold and the interest retained is accounted for on the basis of the fair value of the retained interests and a gain or loss is recognized if the divestiture significantly affects the depletion rate.

Unproved Oil and Natural Gas Properties

Unproved oil and natural gas properties consist of costs incurred to acquire unproved leases. Unproved lease acquisition costs are capitalized until the leases expire or when we specifically identify leases that will revert to the lessor, at which time we charge the associated unproved lease acquisition costs to exploration costs. Lease acquisition costs related to successful drilling are reclassified to proved oil and natural gas properties.

Upon the sale of an entire interest in an unproved property for cash or cash equivalents, a gain or loss is recognized to the extent of the difference between the proceeds received and the net carrying value of the property. Proceeds from the sale of partial interests in unproved oil and natural gas properties are accounted for as a recovery of costs unless the proceeds exceed the entire cost of the property.

Impairment of Oil and Natural Gas Properties

The cost of proved oil and natural gas properties are assessed on a field-by-field basis for impairment at least annually or whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. The expected undiscounted future cash flows of the oil and natural gas properties are compared to the carrying amount of the oil, natural gas and NGL properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the carrying amount of the oil and natural gas properties is adjusted to estimated fair value. Assumptions associated with discounted cash flow models or valuations used in the impairment evaluation include estimates of future oil, natural gas and NGL prices, production costs, development expenditures, anticipated production of proved reserves, appropriate risk-adjusted discount rates and other relevant data. Unproved oil and natural gas properties are assessed periodically for impairment on a property-by-property basis based on remaining lease terms, drilling results or future plans to develop acreage. See further discussion in Note 7 – Fair Value Measurements.

Business Combinations

In accordance with ASC 805 - Business Combinations, the Company accounts for its acquisitions that qualify as a business using the acquisition method. If the set of assets and activities acquired is not considered a business, it is accounted for as an asset acquisition using a cost accumulation model. In the cost accumulation model, the cost of the acquisition, including certain transaction costs, is allocated to the assets acquired on the basis of relative fair values.

The Company includes the results of operations of acquired businesses beginning on the respective acquisition dates. In accordance with the acquisition method, the Company allocates the purchase price of an acquired business to its identifiable assets and liabilities based on the estimated fair values. Transaction costs related to the business combination are expensed as incurred. This fair value measurement is based on unobservable (Level 3) inputs. The excess of the purchase price over the amount allocated to the assets and liabilities, if any, is recorded as goodwill. The excess value of the net identifiable assets and liabilities acquired over the purchase price of an acquired business, if any, is recorded as a bargain purchase gain.

Other Property and Equipment, Net

Property and equipment are capitalized and recorded at cost, while maintenance and repairs are expensed. Depreciation of such property and equipment is computed using the straight-line method over the estimated useful lives of the assets, which range from 5 to 39 years. Capitalized costs related to leasehold improvements are depreciated over the life of the lease.

Deferred Financing Costs

Deferred financing costs include origination, arrangement, legal and other fees to issue or amend the terms of credit facility agreements. These deferred financing costs are reported as other non-current assets and recognized on the consolidated statement of operations as interest expense by amortizing the costs over the related financing using the straight-line method, which approximates the effective interest method.

Equity Issuance Costs

Equity issuance costs include underwriter, legal, accounting, printing and other fees to issue common equity securities. These issuance costs are netted against offering proceeds at the time of issuance and are reported as other non-current assets when related to the issuance of common equity securities. The issuance costs are expensed to the consolidated statement of operations if the issuance is unsuccessful.

Other Non-Current Assets, Net

Other non-current assets consisted of the following:

	December 31, 2021	September 30, 2021
	(In thousands)	
Deferred financing costs, net	$ 1,345	$ 1,353
Prepayments to outside operators	690	707
Right of use assets	208	309
Other deposits	50	50
Total other non-current assets, net	$ 2,293	$ 2,419

Accrued Liabilities

Accrued liabilities consisted of the following:

	December 31, 2021	September 30, 2021
	(In thousands)	
Accrued capital expenditures	$ 5,618	$ 9,718
Accrued lease operating expenses	2,534	2,428
Accrued general and administrative costs	3,404	4,375
Other accrued expenditures	1,318	2,834
Total accrued liabilities	$ 12,874	$ 19,355

Asset Retirement Obligations

ARO consist of future plugging and abandonment expenses on oil and natural gas properties. The fair value of the ARO is recorded as a liability in the period in which wells are drilled with a corresponding increase in the carrying amount of oil and natural gas properties. The liability is accreted for the change in its present value each period and the capitalized cost is depreciated using the units-of-production method. The asset and liability are adjusted for changes resulting from revisions to the timing or the amount of the original estimate when deemed necessary. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized.

Components of the changes in ARO for the three months ended December 31, 2021 and year ended September 30, 2021 are shown below:

	December 31, 2021	September 30, 2021
	(In thousands)	
ARO, beginning balance	$ 2,434	$ 2,326
Liabilities incurred	56	113
Liability settlements and disposals	(58)	(92)
Accretion	21	87
ARO, ending balance	2,453	2,434
Less: current ARO[1]	(192)	(128)
ARO, long-term	$ 2,261	$ 2,306

(1) Current ARO is included within other current liabilities on the accompanying consolidated balance sheets.

Goodwill

Goodwill represents the future economic benefit arising from other assets acquired in a business combination that are not individually identified or separately recognized. Goodwill is initially recognized as the excess of the purchase price of a business combination over the fair value of the net assets acquired and is tested for impairment annually in accordance with ASC 350 - Intangibles - Goodwill and Other, or more frequently if there is a change in events or circumstances that indicate the carrying value of the goodwill may not be recoverable.

The impairment test should occur at the reporting unit level determined by the Company and an impairment should only exist if the Company has determined the carrying value of the goodwill no longer exceeds the implied fair value. If the Company determines it is more likely than not the fair value of the reporting unit is less than its carrying value, including goodwill, then a quantitative assessment is necessary. An impairment loss is recognized if the carrying value of the reporting unit goodwill exceeds the implied fair value of that goodwill.

The Company assessed the goodwill balance recognized from the Merger of $19.0 million for impairment since the Company entered into a purchase and sale agreement on March 10, 2021 for $3.5 million before closing adjustments. At the closing of the Merger, the Company determined it had two reporting units, and the entire goodwill balance of $19.0 million was included in the reporting unit acquired in the Merger (the "Kansas Reporting Unit"). The Company did not fully integrate the Kansas Reporting Unit in the Company's operations as it was deemed to be held for sale upon acquisition. See further discussion in Note 4 - Acquisitions and Divestitures. The carrying value of the Kansas Reporting Unit was $22.0 million. At the closing of the Merger, the Company concluded the fair value of the Kansas Reporting Unit was $3.5 million. As the carrying value exceeded the implied fair value at the time of the closing of the Merger, the Company concluded the goodwill balance associated with the Kansas Reporting Unit was impaired and recognized a goodwill impairment loss, included within loss from discontinued operations on the consolidated statement of operations, of $18.5 million during the year ended September 30, 2021.

Revenue Recognition

Oil Sales

Under the Company’s oil sales contracts, oil that is produced by the Company is delivered to the purchaser at a contractually agreed-upon delivery point at which point the purchaser takes custody, title and risk of loss of the product. Once control has been transferred, the purchaser transports the product to a third party and receives market-based prices from the third party. The Company receives a percentage of proceeds received by the purchaser less transportation costs in accordance with the pricing provisions in the Company's contracts. As transportation costs are incurred after the transfer of control, the costs are included in oil and natural gas sales and represent part of the transaction price of the contract. The pricing provisions also provide quantity requirements and grade and quality specifications. The Company recognizes revenue at the net price received when control transfers to the purchaser.

Natural Gas and NGL Sales

Under the Company’s natural gas gathering and processing contracts, natural gas is delivered to the purchaser at the inlet of the purchasers' gathering system, at which point title and risk of loss is transferred to the purchaser. The purchaser gathers and processes the natural gas and remits proceeds to the Company for the resulting sales of natural gas and NGLs in accordance with the pricing provisions of the Company's contracts. As the gathering, processing and transportation activities occur after the transfer of control, these costs are netted against our oil and natural gas sales and represent part of the transaction price of the contract, and may exceed the sales price. The pricing provisions also provide quantity requirements and grade and quality specifications. The Company recognizes revenue on a net basis for amounts expected to be received from third party customers through the marketing process.

Transaction Price Allocated to Remaining Performance Obligations

For the contracts that are short term in nature with a contract term of one year or less, the Company applies the practical expedient in ASC 606 exempting the disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less. Based on the Company’s current product sales contracts, with contract terms ranging from one to ten years, each unit of production is considered a separate performance obligation and therefore future production volumes are wholly unsatisfied and do not require allocation or disclosure of the transaction price to remaining performance obligations.

Contract Balances

Under the Company’s product sales contracts, the Company has the right to invoice customers once the performance obligations have been satisfied, at which point payment is unconditional. Accordingly, the Company’s product sales contracts do not give rise to contract assets or liabilities under ASC 606.

Prior-Period Performance Obligations

Revenue is recorded in the month in which production is delivered to the purchaser. However, certain settlement statements for oil, natural gas and NGLs may not be received for thirty to ninety days after the date production is delivered and, as a result, the Company is required to estimate the amount of production delivered to the purchaser and the price that will be received for the sale of the product. Differences identified between the Company’s revenue estimates and actual revenue received historically have not been significant. For the three months ended December 31, 2021 and 2020, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

Disaggregation of Revenue

The following table presents oil and natural gas sales disaggregated by product:

	Three Months Ended December 31,	
	2021	2020
	(In thousands)	
Oil and natural gas sales:		
Oil	$ 50,623	$ 22,107
Natural gas	2,705	119
Natural gas liquids	3,322	188
Total oil and natural gas sales, net	$ 56,650	$ 22,414

Contract Services with Related Parties

The Company has contracts with related parties to provide certain contract operating, accounting and back-office support services. Revenue related to these contract services is recognized over time as the services are rendered, and the fee is stated within the contract at a fixed monthly rate. Costs directly attributable to performing these services are also recognized as the services are rendered. Refer to Note 8 – Transactions with Related Parties for a more detailed discussion regarding these contracts.

Revenue Payable

For certain oil and natural gas properties, where the Company serves as operator, the Company receives production proceeds from the purchaser and further distributes such amounts to other revenue and royalty owners. Production proceeds that the Company has not yet distributed to other revenue and royalty owners are reflected as revenue payable in the consolidated balance sheets.

Lease Operating Expenses

Lease operating costs, including payroll for field personnel, saltwater disposal, electricity, generator rentals, diesel fuel and other operating expenses, are expensed as incurred and included in lease operating expenses in our consolidated statements of operations.

Income Taxes

Upon closing of the Merger on February 26, 2021, Tengasco was renamed to Riley Exploration Permian, Inc. and REP LLC became a wholly-owned subsidiary of Riley Permian, the consolidated company. In addition, Riley Permian became a C-corporation which is subject to current federal and state income taxes, including Texas Margin Tax. See further discussion in Note 4 - Acquisitions and Divestitures and in Note 12 - Income Taxes.

Riley Permian uses the asset and liability method of accounting for income taxes, which requires the establishment of deferred tax accounts for all temporary differences between: (i) financial reporting and tax bases of assets and liabilities, using currently enacted federal and state income tax rates, and (ii) operating loss and tax credit carryforwards. In addition, deferred tax accounts must be adjusted to reflect new rates if enacted into law.

Realization of deferred tax assets is contingent on the generation of future taxable income. As a result, management considers whether it is more likely than not that all or a portion of such assets will be realized during periods when they are available, and if not, management provides a valuation allowance for amounts not likely to be recognized.

Management periodically evaluates tax reporting methods to determine if any uncertain tax positions exist that would require the establishment of a loss contingency. A loss contingency would be recognized if it were probable that a liability has been incurred as of the date of the financial statements and the amount of the loss can be reasonably estimated. The amount recognized is subject to estimates and management's judgment with respect to the likely outcome of each uncertain tax position. The amount that is ultimately incurred for an individual uncertain tax position or for all uncertain tax positions in the aggregate could differ from the amount recognized. Interest and penalties, if any, related to uncertain tax positions are included in current income tax expense. There are no unrecorded liabilities for uncertain tax positions related to the Company as of December 31, 2021 and September 30, 2021.

Interest Expense

We have financed a portion of our working capital requirements, capital expenditures and certain acquisitions with borrowings under our revolving credit facility. We incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. Interest expense in the consolidated statements of operations reflects interest, unused commitment fees paid to our lender, interest rate swap settlements plus the amortization of deferred financing costs (including origination and amendment fees). Interest expense was $0.9 million and $1.2 million for the three months ended December 31, 2021 and 2020, respectively.

Concentrations of Credit Risk

Our customer concentration may impact our overall credit risk, either positively or negatively, in that these entities may be similarly affected by changes in economic or other conditions affecting the oil and natural gas industry.

We sell our production at market prices and to a relatively small number of purchasers, as is customary in the exploration, development and production business. Our purchaser contracts include marketing provisions with our purchasers to market our production. For the three months ended December 31, 2021 and 2020, one purchaser accounted for 87% and 86%, respectively, of our revenue purchased, with three end customers each accounting for more than 10% of the purchased revenue. During such periods, no other purchaser accounted for 10% or more of our revenues. The loss of this purchaser could materially and adversely affect our revenues in the short-term. However, the end customers include companies with lower credit risk. Further, based on the current demand for oil and natural gas and the availability of other purchasers, we believe that the loss of any of our purchasers would not have a long-term material adverse effect on our financial condition and results of operations because oil, natural gas and NGLs are marketable products with well-established markets.

We manage credit risk related to accounts receivable through credit approvals, escrow accounts and monitoring procedures. Accounts receivable are generally not collateralized. However, we routinely assess the financial strength of our customers and, based upon factors surrounding the credit risk, establish an allowance for uncollectible accounts, if required. As a result, we believe that our accounts receivable credit risk exposure beyond such allowance is limited.

Environmental and Other Issues

We are engaged in oil and natural gas exploration and production and may become subject to certain liabilities as they relate to environmental cleanup of well sites or other environmental restoration procedures. In connection with our acquisition of existing or previously drilled well bores, we may not be aware of what environmental safeguards were taken at the time such wells were drilled or during such time the wells were operated. Should it be determined that a liability exists with respect to any environmental cleanup or restoration, we would be responsible for curing such a violation.

We account for environmental contingencies in accordance with the accounting guidance related to accounting for contingencies. Environmental expenditures that relate to current operations are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations, which do not contribute to current or future revenue generation, are expensed. Liabilities are recorded when environmental assessments and/or clean-ups are probable, and the costs can be reasonably estimated.

Fair Value Measurements

Certain financial instruments are reported at fair value on our consolidated balance sheets. Under fair value measurement accounting guidance, fair value is defined as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants (i.e., an exit price). To estimate an exit price, a three-level hierarchy is used. The fair value hierarchy prioritizes the inputs, which refer broadly to assumptions market participants would use in pricing an asset or a liability, into three levels. Level 1 inputs are unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. Level 2 inputs are inputs other than quoted prices within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for the asset or liability and have the lowest priority.

The valuation techniques that may be used to measure fair value include a market approach, an income approach and a cost approach. A market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. An income approach uses valuation techniques to convert future amounts to a single present amount based on current market expectations, including present value techniques, option-pricing models and the excess earnings method. The cost approach is based on the amount that currently would be required to replace the service capacity of an asset (replacement cost).

The carrying values of financial instruments comprising cash and cash equivalents, payables, receivables, related party accounts receivable/payable and advances from joint interest owners approximate fair values due to the short-term maturities of these instruments. The carrying value reported for the revolving credit facility approximates fair value because the underlying instruments are at interest rates which approximate current market rates.

Derivative Contracts

We report the fair value of derivatives on the consolidated balance sheets in derivative assets and derivative liabilities as either current or non-current based on the timing of the settlement of individual trades. Trades that are scheduled to settle in the next twelve months are reported as current. The Company nets derivative assets and liabilities, in the consolidated balance sheets, whenever it has a legally enforceable master netting agreement with the counterparty to a derivative contract.

For the three months ended December 31, 2021 and 2020, we have not designated our derivative contracts as hedges for accounting purposes, and therefore changes in the fair value of derivatives are recognized in earnings. Cash settlements of contracts are included in cash flows from operating activities in the consolidated statement of cash flows. Derivative contracts are settled on a monthly basis.

The fair value of the derivatives is established using index prices, volatility curves and discount factors. The value we report in our consolidated financial statements is as of a point in time and subsequently change as these estimates are revised to reflect actual results, changes in market conditions and other factors.

The use of derivatives involves the risk that the counterparties to such contracts will be unable to meet their obligations under the terms of the agreement. To minimize the credit risk with derivative instruments, it is our policy to enter into derivative contracts primarily with counterparties that are financial institutions that are also lenders within our revolving credit facility. Under the terms of the current counterparties' contracts, only those that are lenders under our revolving credit facility are secured by the same collateral as outlined in our revolving credit facility. The counterparties are not required to provide credit support to the Company. See further discussion in Note 6 – Derivative Instruments.

Leases

The Company reviews all contracts to determine if a lease exists at contract inception. A lease exists when the Company has the right to obtain substantially all of the economic benefit of a specific asset and to control the use of that asset over the term of the agreement. Identified leases are classified as an operating or finance lease, which determines the recognition, measurement and presentation of expenses. As of December 31, 2021 and September 30, 2021, the Company did not have any finance leases. Operating leases are capitalized on the consolidated balance sheet at commencement through a lease right-of-use ("ROU") asset and lease liability representing the present value of lease payments over the lease term. In addition to the present value of lease payments, the operating lease ROU asset includes any lease payments made to the lessor prior to lease commencement less any lease incentives and initial direct costs incurred. Options to extend or terminate leases are included in the lease term when it is reasonably certain the Company will exercise the option. For operating leases, lease costs are recognized on a straight-line basis over the term of the lease.

The present value of operating lease payments and amortization of the lease liability is calculated using a discount rate. When available, the Company uses the rate implicit in the lease as the discount rate; however, most of the Company's leases do not provide a readily determinable implicit rate. In such cases, the Company is required to use its incremental borrowing rate ("IBR"). The Company's IBR reflects the estimated rate of interest that the Company would pay to borrow on a collateralized basis over a similar term and amount equal to the lease payments in a similar economic environment. The Company is required to reassess the discount rate for any new and modified lease contracts as of the lease effective date. The weighted-average discount rate was 5.17% at December 31, 2021.

	December 31, 2021	September 30, 2021
	(In thousands)	
ROU asset	$ 208	$ 309
Current lease liability	$ 212	$ 314

The ROU asset and current lease liability was included in other non-current assets and other current liabilities and non-current lease liabilities, respectively, on the accompanying consolidated balance sheets. Lease expense for the Company was included in general and administrative costs on the accompanying consolidated statements of operations.

Recent Accounting Pronouncements

In December 2019, the FASB issued ASU No. 2019-12, "Income Taxes (Topic 740) - Simplifying the Accounting for Income Taxes." This update is intended to simplify the accounting for income taxes by removing certain exceptions and by clarifying and amending existing guidance and is effective for public business entities beginning after December 15, 2020 with early adoption permitted. The Company adopted this ASU effective October 1, 2021. The adoption of this ASU did not have a material impact on the Company's consolidated financial statements.

In March 2020, the FASB issued ASU No. 2020-04, "Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting" ("ASU 2020-04"), which provides companies with optional guidance to ease the potential accounting burden associated with transitioning away from reference rates (e.g., LIBOR) that are expected to be discontinued. ASU 2020-04 allows, among other things, certain contract modifications, such as those within the scope of Topic 470 on debt, to be accounted as a continuation of the existing contract. The Company adopted this ASU effective concurrent with the amendment of the Company's revolving credit facility in April 2022. See Note 9 - Revolving Credit Facility for additional information on the amendment of the revolving credit facility. The adoption of this ASU did not have a material impact on the Company's consolidated financial statements.

(4) Acquisitions

Business Combination Between REP LLC and Tengasco

Immediately prior to the closing of the Merger on February 26, 2021, REP LLC converted all of its issued and outstanding Series A Preferred Units into common units of REP LLC. In connection with the Merger, holders of common units of REP LLC were entitled to receive, in exchange for each common unit, shares of common stock of Tengasco (which was renamed Riley Exploration Permian, Inc.), par value $0.001 per share ("Tengasco common stock") based on the exchange ratio set forth in the Merger Agreement (the "Exchange Ratio"), with cash paid in lieu of the issuance of any fractional shares. The Exchange Ratio was 97.796467 shares of Tengasco common stock for each common unit of REP LLC (as adjusted for the reverse stock split). Immediately prior to the closing of the Merger, Tengasco effected a one-for-twelve reverse stock split resulting in outstanding common stock of approximately 17.8 million shares including shares of Tengasco common stock issued in the Merger.

The combination between REP LLC and Tengasco qualified as a business combination, with REP LLC being treated as the accounting acquirer. The assets acquired and liabilities assumed were recognized on the consolidated balance sheet at fair value as of the acquisition date. The fair value measurements of the oil and natural gas properties acquired and asset retirement obligations assumed were derived utilizing an income approach and based, in part, on significant inputs not observable in the market. These inputs represent Level 3 measurements in the fair value hierarchy and include, but are not limited to, estimates of reserves, future commodity prices, future development, future operating costs, future cash flows and the use of weighted average cost of capital. These inputs required the use of significant judgements and estimates at the date of valuation.

The consideration paid in the Merger by REP LLC as the accounting acquirer totaled approximately $26.4 million and was determined based on the closing price of Tengasco's common stock on February 26, 2021 and the total number of shares outstanding immediately prior to the Merger. The Merger was structured as a tax-free reorganization for United States federal income tax purposes.

The following table summarizes the consideration for the Merger (presented in thousands, except stock price):

Tengasco common stock price	$	29.64
Tengasco common stock - issued and outstanding as of February 26, 2021		891
Total consideration	$	26,392

The Company incurred $1.0 million of costs related to the Merger during the three months ended December 31, 2020, which is included in transaction costs on the consolidated statement of operations.

The Company completed the determination of the fair value attributable to the assets acquired and liabilities assumed as of September 30, 2021. The following table presents the allocation of the purchase price to the assets acquired and liabilities assumed based on their fair values on February 26, 2021 (in thousands):

Assets		
Cash and cash equivalents	$	860
Account receivable		325
Prepaid and other current assets		759
Total current assets		**1,944**
Oil and gas properties		4,525
Other property and equipment		91
Right of use assets		42
Other non-current assets		4
Deferred tax assets		2,987
Total assets acquired	**$**	**9,593**
Liabilities		
Accounts payable	$	130
Accrued liabilities		409
Current lease liabilities, operating		42
Current lease liabilities, financing		68
Total current liabilities		**649**
Asset retirement obligations		1,565
Total liabilities assumed		**2,214**
Net identifiable assets acquired		7,379
Goodwill		19,013
Net assets acquired	**$**	**26,392**

The goodwill recognized was primarily attributable to a substantial increase in the stock price of Tengasco on the Closing Date, which increased the amount of the consideration transferred. The Company does not expect goodwill to be deductible for tax purposes.

Pro Forma Operating Results (Unaudited)

The following unaudited pro forma combined results for the three months ended December 31, 2020 reflect the consolidated results of operations of the Company as if the Merger had occurred on October 1, 2019. The unaudited pro forma information includes adjustments for $0.9 million of transaction costs being reclassified to the three months ended December 31, 2019 which were incurred during the three months ended December 31, 2020. Additionally, the Company adjusted for $0.9 million of oil and natural gas property impairment Tengasco recognized under the full-cost method of accounting, which would not have been recognized under the successful efforts method, during the three months ended December 31, 2020. Also, the unaudited pro forma information has been tax affected using a 21% tax rate. The common stock was also adjusted for the conversion of the REP LLC preferred units into common units and retroactively adjusted for the Exchange Ratio and one-for-twelve reverse stock split.

	Three Months Ended December 31, 2020
	(In thousands, except per share/unit amounts) *(Unaudited)*
Total Revenues	$ 23,014
Pro Forma Net Income (Loss) before Taxes	(6,647)
Pro forma income tax benefit (expense)	1,396
Pro Forma Net Income (Loss)	$ (5,251)
Net Income (Loss) per Share/Unit from Continuing Operations:	
Basic	$ (0.30)
Diluted	$ (0.30)

The unaudited pro forma combined financial information is for informational purposes only and is not intended to represent or to be indicative of the combined results of operations that the Company would have reported had the Merger been completed as of October 1, 2019 and should not be taken as indicative of the Company's future combined results of operations. The actual results may differ significantly from that reflected in the unaudited pro forma combined financial information for a number of reasons, including, but not limited to, differences in assumptions used to prepare the unaudited pro forma combined financial information and actual results.

Divestitures

On April 2, 2021, the Company closed on the sale of the Kansas Reporting Unit for an agreed upon purchase price of $3.5 million, less approximately $0.2 million of closing adjustments.

(5) Oil and Natural Gas Properties

Oil and natural gas properties are summarized below:

	December 31, 2021	September 30, 2021
	(In thousands)	
Proved	$ 421,779	$ 402,165
Unproved	18,839	20,557
Work-in-progress	13,534	11,411
	454,152	434,133
Accumulated depletion and amortization	(95,021)	(88,336)
Total oil and natural gas properties, net	$ 359,131	$ 345,797

At December 31, 2021 and September 30, 2021, the Company had one exploratory well drilled but uncompleted that was included in work-in-progress with associated well costs of $3.7 million for both periods. At December 31, 2021, the Company had one exploratory well with costs of $3.7 million that has been capitalized for greater than one year but less than two years. The Company is evaluating completion methods for this exploratory well.

Depletion and amortization expense for proved oil and natural gas properties was $6.7 million and $5.9 million for the three months ended December 31, 2021 and 2020, respectively.

The Company incurred $0.6 million and $0.4 million of exploration costs, which primarily related to the expiration of oil and natural gas leases for the three months ended December 31, 2021 and 2020, respectively.

(6) Derivative Instruments

Oil and Natural Gas Contracts

The Company uses commodity based derivative contracts to reduce exposure to fluctuations in oil and natural gas prices. While the use of these contracts limits the downside risk for adverse price changes, their use may also limit future revenues from favorable price changes. For the three months ended December 31, 2021 and 2020, we have not designated our derivative contracts as hedges for accounting purposes, and therefore changes in the fair value of derivatives are included and recognized in other income (expenses) in the consolidated statements of operations.

As of December 31, 2021, the Company's oil and natural gas derivative instruments consisted of the following types:

- Fixed Price Swaps – the Company receives a fixed price for the contract and pays a floating market price to the counterparty over a specified period for a contracted volume.
- Costless collars – the combination of a put option (fixed floor) and call option (fixed ceiling), with the options structured so that the premium paid to purchase the put option is offset by the premium received from the sale of the call option. If the market price exceeds the call strike price or falls below the put strike price, we receive the fixed price and pay the market price. If the market price is between the put and the call strike price, no payments are due from either party.
- Basis Protection Swaps – basis swaps are settled based on differences between a fixed price differential and the differential between the settlement prices of two referenced indexes. We receive the fixed price differential and pay the differential between the referenced indexes.

The following table summarizes the open financial derivative positions as of December 31, 2021, related to oil and natural gas production:

Calendar Quarter	Notional Volume	Weighted Average Price		
		Fixed	Put	Call
		($ per unit)		
Oil Swaps (Bbl)				
Q1 2022	345,000	$ 57.47	$ —	$ —
Q2 2022	345,000	$ 57.47	$ —	$ —
Q3 2022	270,000	$ 56.03	$ —	$ —
Q4 2022	270,000	$ 56.03	$ —	$ —
2023	720,000	$ 53.27	$ —	$ —
Natural Gas Swaps (Mcf)				
Q1 2022	360,000	$ 3.26	$ —	$ —
Q2 2022	540,000	$ 3.26	$ —	$ —
Q3 2022	540,000	$ 3.26	$ —	$ —
Q4 2022	540,000	$ 3.26	$ —	$ —
Oil Collars (Bbl)				
Q1 2022	90,000	$ —	$ 35.00	$ 42.63
Q2 2022	90,000	$ —	$ 35.00	$ 42.63
Q3 2022	90,000	$ —	$ 35.00	$ 42.63
Q4 2022	90,000	$ —	$ 35.00	$ 42.63
Oil Basis (Bbl)				
Q1 2022	240,000	$ 0.41	$ —	$ —
Q2 2022	240,000	$ 0.41	$ —	$ —
Q3 2022	240,000	$ 0.41	$ —	$ —
Q4 2022	240,000	$ 0.41	$ —	$ —

Interest Rate Contracts

The Company has entered into floating-to-fixed interest rate swaps (we receive a floating market rate equal to one-month LIBOR and pay a fixed interest rate) to manage interest rate exposure related to the Company's revolving credit facility.

The following table summarizes the open interest rate derivative positions as of December 31, 2021:

Open Coverage Period	Notional Amount	Fixed Rate
	(In thousands)	
Floating-to-Fixed Interest Rate Swaps		
January 2022 - September 2023	$ 40,000	0.24 %

Balance Sheet Presentation of Derivatives

The following table presents the location and fair value of the Company’s derivative contracts included in the consolidated balance sheets as of December 31, 2021 and September 30, 2021:

	December 31, 2021		
Balance Sheet Classification	**Gross Fair Value**	**Amounts Netted**	**Net Fair Value**
		(In thousands)	
Current derivative assets	$ 281	$ (198)	$ 83
Non-current derivative assets	267	—	267
Current derivative liabilities	(31,182)	198	(30,984)
Non-current derivative liabilities	(9,515)	—	(9,515)
Total	$ (40,149)	$ —	$ (40,149)

	September 30, 2021		
Balance Sheet Classification	**Gross Fair Value**	**Amounts Netted**	**Net Fair Value**
		(In thousands)	
Current derivative assets	$ 186	$ (186)	$ —
Non-current derivative assets	228	(122)	106
Current derivative liabilities	(42,330)	186	(42,144)
Non-current derivative liabilities	(9,054)	122	(8,932)
Total	$ (50,970)	$ —	$ (50,970)

The following table presents the components of the Company's loss on derivatives for the three months ended December 31, 2021 and 2020:

	Three Months Ended December 31,	
	2021	**2020**
	(In thousands)	
Settlements on derivative contracts	$ (16,014)	$ 5,173
Non-cash gain (loss) on derivatives	10,821	(19,082)
Loss on derivatives	$ (5,193)	$ (13,909)

(7) Fair Value Measurements

The FASB has established a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy consists of three broad levels. Level 1 inputs are the highest priority and consist of unadjusted quoted prices in active markets for identical assets and liabilities. Level 2 are inputs other than quoted prices that are observable for the asset or liability, either directly or indirectly. Level 3 are unobservable inputs for an asset or liability.

The carrying values of financial instruments comprising cash and cash equivalents, payables, receivables, related party accounts receivable and accounts payable, and advances from joint interest owners approximate fair values due to the short-term maturities of these instruments. The carrying value reported for the revolving line of credit approximates fair value because the underlying instruments are at interest rates which approximate current market rates. The revolving line of credit is considered a Level 3 measurement.

Assets and Liabilities Measured on a Recurring Basis

The fair value of commodity derivatives and interest rate swaps is estimated using internal discounted cash flow calculations based upon forward curves. The following table presents the Company’s financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2021 and September 30, 2021, by Level within the fair value hierarchy:

	December 31, 2021			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Financial assets:				
Commodity derivative assets	$ —	$ 187	$ —	$ —
Interest rate assets	$ —	$ 361	$ —	$ —
Financial liabilities:				
Commodity derivative liabilities	$ —	$ (40,687)	$ —	$ —
Interest rate liabilities	$ —	$ (10)	$ —	$ —

	September 30, 2021			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Financial assets:				
Commodity derivative assets	$ —	$ 308	$ —	$ —
Interest rate assets	$ —	$ 106	$ —	$ —
Financial liabilities:				
Commodity derivative liabilities	$ —	$ (51,336)	$ —	$ —
Interest rate liabilities	$ —	$ (48)	$ —	$ —

Assets and Liabilities Measured at Fair Value on a Non-Recurring Basis

Assets and liabilities accounted for at fair value on a non-recurring basis in accordance with the fair value hierarchy include the initial recognition of asset retirement obligations, the fair value of oil and natural gas properties, and goodwill when acquired in a business combination or assessed for impairment.

The fair value measurements of assets acquired and liabilities assumed are measured on a non-recurring basis on the acquisition date using an income valuation technique based on inputs that are not observable in the market and therefore represent Level 3 inputs. Significant inputs used to determine the fair value include estimates of: (i) reserves; (ii) future commodity prices; (iii) operating and development costs; and (iv) a market-based weighted average cost of capital rate. The underlying commodity prices embedded in the Company's estimated cash flows are the product of a process that begins with NYMEX forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that the Company’s management believes will impact realizable prices. These inputs require significant judgments and estimates by the Company’s management at the time of the valuation.

The fair value of asset retirement obligations incurred and acquired during the three months ended December 31, 2021 and year ended September 30, 2021, totaled approximately $56 thousand and $113 thousand, respectively. The fair value of additions to the asset retirement obligation liabilities is measured using valuation techniques consistent with the income approach, which converts future cash flows to a single discounted amount. Significant inputs to the valuation include: (i) estimated plug and abandonment cost per well for all oil and natural gas wells and for all disposal wells; (ii) estimated remaining life per well; (iii) future inflation factors; and (iv) our average credit-adjusted risk-free rate. These assumptions represent Level 3 inputs.

If the carrying amount of our oil and natural gas properties exceeds the estimated undiscounted future cash flows, we will adjust the carrying amount of the oil and natural gas properties to fair value. The fair value of our oil and natural gas properties is determined using valuation techniques consistent with the income and market approach. The factors used to determine fair value are subject to management’s judgment and expertise and include, but are not limited to, recent sales prices of comparable properties, the present value of future cash flows, net of estimated operating and development costs using estimates of proved reserves, future commodity pricing, future production estimates, anticipated capital expenditures, and various discount rates commensurate with the risk and current market conditions associated with the expected cash flow projected. These assumptions represent Level 3 inputs.

(8) Transactions with Related Parties

Contract Services

RPOC provides certain administrative services to Combo Resources, LLC ("Combo") and is also the contract operator on behalf of Combo in exchange for a monthly fee of $100 thousand and reimbursement of all third party expenses pursuant to a contract services agreement. RPOC also has the option to participate as a working interest owner in Combo wells operated by RPOC. Combo was previously owned by Oakspring Energy Holdings, LLC ("Oakspring") and by a wholly-owned subsidiary of Riley Exploration Group, Inc. ("REG"). On December 31, 2020, Oakspring contributed its interest in Combo to certain investment funds of Yorktown Partners, LLC, and the wholly-owned subsidiary of REG contributed its interest in Combo to Riley Exploration Group, LLC. Combo and REG are portfolio companies of Yorktown Energy Partners XI, L.P. ("Yorktown XI"), certain managed funds of which have investments in the Company (all deemed to be related parties). One of our executives held positions with REG and Combo at December 31, 2021. Our Executive Vice President, Business Intelligence is the President of both REG and Combo, as well as a board member of Combo.

Additionally, RPOC provides certain administrative and operational services to Riley Exploration Group, LLC ("REG") in exchange for a monthly fee of $100 thousand pursuant to a contract services agreement.

The following table presents revenues from contract services for related parties:

	Three Months Ended December 31,	
	2021	2020
	(In thousands)	
Combo	$ 300	$ 300
REG	300	300
Contract services - related parties	$ 600	$ 600
Cost of contract services	$ 150	$ 148

The Company had amounts (payable to) and due from Combo of $(0.2) million and $0.5 million at December 31, 2021 and September 30, 2021, respectively, which are reflected in accounts payable - related parties and accounts receivable - related parties on the accompanying consolidated balance sheets. There were no amounts due to the Company from REG as of December 31, 2021 and September 30, 2021.

Consulting and Legal Fees

The Company has an engagement agreement with di Santo Law PLLC ("di Santo Law"), a law firm owned by Beth di Santo, a member of our Board of Directors, pursuant to which di Santo Law's attorneys provide legal services to the Company. For the three months ended December 31, 2021 and 2020, the Company incurred legal fees from di Santo Law of approximately $0.2 million and $0.2 million, respectively. As of December 31, 2021 and September 30, 2021, the Company had approximately $0.2 million and $0.8 million in amounts accrued for di Santo Law. Such amounts were included in accrued liabilities in the accompanying consolidated balance sheets.

(9) Revolving Credit Facility

On September 28, 2017, REP LLC entered into a credit agreement (the "Credit Agreement") to establish a senior secured revolving credit facility with a syndicate of banks including SunTrust Bank, now Truist Bank as successor by merger, as administrative agent. The revolving credit facility had an initial borrowing base of $25 million with a maximum facility amount of $500 million. On October 12, 2021, the revolving credit facility was amended to, among other things, increase the borrowing base to $175 million from $135 million, provide for the transition away from LIBOR to an alternative reference rate and change the requirements for Restricted Payments (as defined in the Credit Agreement) to consider the Company's total leverage ratio and available free cash flow under certain circumstances. Substantially all of the Company's assets are pledged to secure the revolving credit facility.

On April 29, 2022, the Company amended its Credit Agreement to, among other things, increase the borrowing base from $175 million to $200 million, extend the maturity date to April 2026, replace LIBOR with SOFR and change the requirements for hedging to be based on utilization of the borrowing base and the Company's leverage ratio ranging between 0% and 50% (depending on the borrowing base utilization percentage and leverage ratio as of the hedge evaluation date) of its proved developed producing volumes.

The borrowing base is subject to periodic redeterminations, mandatory reductions and further adjustments from time to time. The facility currently requires semi-annual redeterminations on February 1 and August 1. During these redetermination periods, the Company's borrowing base may be increased and may also be reduced in certain circumstances. The revolving credit facility allows for Eurodollar Loans and Base Rate Loans (each as defined in the Credit Agreement). The interest rate on each Eurodollar Loan will be the adjusted LIBOR for the applicable interest period plus a margin between 2.75% and 3.75% (depending on the borrowing base utilization percentage). The annual interest rate on each Base Rate Loan is (i) the greatest of (a) the administrative agent's prime lending rate, (b) the federal funds rate plus 0.5% per annum or (c) the adjusted LIBOR determined on a daily basis for an interest period of one-month, plus 1.00% per annum, plus (ii) a margin between 1.75% and 2.75% (depending on the borrowing base utilization percentage). The Company is also subject to an unused commitment fee of between 0.375% and 0.500% (depending on the borrowing base utilization percentage).

The Credit Agreement contains certain covenants, which, among other things, require the maintenance of (i) a total leverage ratio of not more than 3.25 to 1.0 and (ii) a minimum current ratio of not less than 1.0 to 1.0 as of the last day of any quarter. The Credit Agreement also contains a total leverage ratio for Restricted Payments after giving pro forma effect to such Restricted Payments, which includes payments to any holder of the Company's shares, would not exceed 2.50 to 1.0. If the Company's leverage ratio, after giving pro forma effect to such Restricted Payments (as defined in the Credit Agreement), is below 2.0 to 1.0, then an additional test of free cash flow is applied, and the Company will only be permitted to make such Restricted Payments if such payment does not exceed the Company's free cash flow. The Company is also required to limit its cash balance to less than $15 million or 10% of the borrowing base, whichever is greater. If the Company's cash balance exceeds this limit for five consecutive business days, the Company will be required to apply the excess to reduce its credit facility borrowings. The Credit Agreement also contains other customary affirmative and negative covenants and events of default. As of December 31, 2021, the Company's minimum hedging requirement was 50% of its PDP volumes on a rolling 24 month basis.

The following table summarizes the Company's interest expense:

	Three Months Ended December 31, 2021	Three Months Ended December 31, 2020
	(In thousands)	
Interest expense	$ 512	$ 1,041
Amortization of deferred financing costs[1]	282	155
Unused commitment fees	102	39
Total interest expense	$ 896	$ 1,235

(1) Includes $0.1 million of unamortized deferred financing costs written off during the three months ended December 31, 2021 in conjunction with the amendment of the Credit Agreement in October 2021.

As of December 31, 2021 and September 30, 2021, the weighted average interest rate on outstanding borrowings under the revolving credit facility was 3.10% and 2.83%, respectively.

As of December 31, 2021 and September 30, 2021, the Company was in compliance with all covenants contained in the Credit Agreement and had $65 million and $60 million, respectively, of outstanding borrowings and an additional $110 million and $75 million, respectively, available under the borrowing base.

(10) Members'/Shareholders' Equity

Public Offering of Common Stock

On June 30, 2021, the Company entered into an Underwriting Agreement (the "Underwriting Agreement") with Truist Securities, Inc., as the representative of the other several underwriters named in the Underwriting Agreement. On July 2, 2021, the Company issued 1,666,667 shares of common stock at a price to the public of $30.00 per share in accordance with the Underwriting Agreement. Net proceeds from the issuance were approximately $46.7 million, after deducting the underwriting fees and other offering costs incurred.

Dividends

For the three months ended December 31, 2021 and 2020, the Company declared quarterly dividends of $0.31 and $0.23 per share of common stock and common units, after giving effect to the adjustment resulting from the one-for-twelve reverse stock split, totaling approximately $6.1 million and $3.8 million, respectively. The cash dividends were declared for all issued and outstanding common shares or units, including vested and unvested under the respective Long-Term Incentive Plan in effect during the period of dividend declaration. The portion of the cash dividend attributable to the unvested restricted shares issued under the 2021 LTIP is included in accrued liabilities on the consolidated balance sheet and will be paid in cash once the unvested restricted shares fully vest. Any accrued but unpaid cash dividends attributable to the unvested restricted shares issued under the 2018 LTIP were paid in accordance with the Merger Agreement immediately prior to consummation of the Merger. See Note 9 - Revolving Credit Facility for discussion over the Company's restrictions on certain payments, including dividends.

Share-Based and Unit-Based Compensation

In connection with the Merger, the Company shareholders adopted an omnibus equity incentive plan, the 2021 LTIP, for the employees, consultants and the directors of the Company and its affiliates who perform services for the Company. The holders of unvested restricted units issued under the 2018 LTIP were issued substitute awards under the 2021 LTIP at the closing of the Merger. Upon the closing of the Merger and after giving effect to the adjustment resulting from the one-for-twelve reverse stock split, the 2021 LTIP had 1,387,022 shares of common stock available for issuance, of which 814,707 shares remained available as of December 31, 2021.

2021 Long-Term Incentive Plan

The 2021 LTIP will provide for potential grants of: (i) incentive stock options qualified as such under U.S. federal income tax laws ("ISO's":); (ii) stock options that do not qualify as incentive stock options; (iii) stock appreciation rights, or SARs; (iv) restricted stock awards; (v) restricted stock units, or RSUs; (vi) stock awards; (vii) performance awards; (viii) dividend equivalents; (ix) other stock-based awards; (x) cash awards; and (xi) substitute awards, all of which will collectively be referred to as the "Awards."

The 2021 LTIP authorizes the Compensation Committee to administer the plan and designate eligible persons as participants, determine the type or types of Awards to be granted to an eligible person, determine the number of shares of stock or amount of cash to be covered by the Awards, approve the forms of award agreements for use under the plan, determine the terms and conditions of any Award, modify, waive or adjust any term or condition of an Award that has been granted, among other responsibilities delegated by the Company's Board.

Restricted Shares: The Company granted 174,575 restricted shares to executive officers and employees of the Company during the three months ended December 31, 2021. The restricted shares granted to executive officers and employees vest over a period of 36 months with a grant date fair value of $23.46. The holder of these restricted shares receives dividends, in arrears, once the shares vest. The Company has accrued for these dividends which are reported in accrued liabilities and other non-current liabilities.

The following table presents the Company's restricted stock activity during the three months ended December 31, 2021 under the 2021 LTIP:

2021 Long-Term Incentive Plan

	Restricted Shares	Weighted Average Grant Date Fair Value
Unvested at September 30, 2021	228,369	$ 15.35
Granted	174,575	$ 23.46
Vested	(36,155)	$ 13.80
Unvested at December 31, 2021	366,789	$ 19.41

During the three months ended December 31, 2021, total share-based compensation expense of $1.0 million is included in general and administrative costs on the Company's consolidated statement of operations for the restricted share awards granted under the 2021 LTIP. At the time of the forfeiture, the Company will recognize any forfeited shares as a reduction to share-based compensation expense on the consolidated statement of operations and a decrease to shareholders' equity on the consolidated balance sheet. Any unpaid dividends on forfeited shares will be recognized as a decrease to accrued liabilities and an increase to shareholders' equity on the consolidated balance sheet. Approximately $5.5 million of additional share-based compensation expense will be recognized over the weighted average life of 28 months for the restricted share awards granted under the 2021 LTIP.

2018 Long-Term Incentive Plan

In connection with the Merger and in accordance with the Merger Agreement, each unvested restricted unit outstanding under the 2018 LTIP was converted into restricted shares of the Company under the 2021 LTIP. The holders of unvested restricted units issued under the 2018 LTIP were issued substitute awards under the 2021 LTIP at the closing of the Merger.

Restricted Units: The Company granted 13,309 restricted units to executives and employees of the Company during the three months ended December 31, 2020. These restricted units vest over a period of 36 months with a fair value price of $112.47. The Company determined the fair value of the common units in accordance with ASC 718 using an options pricing model. Immediately prior to the consummation of the Merger and in accordance with the Merger Agreement, any accrued but unpaid cash dividends on the unvested restricted units issued under the 2018 LTIP was paid.

Total unit-based compensation expense of $0.4 million is included in general and administrative costs on the Company's consolidated statement of operations for all of the issuances outstanding for the three months ended December 31, 2020.

(11) Preferred Units

As of August 13, 2020, REP LLC entered into the Fourth Amended and Restated Limited Liability Company Agreement (the "Fourth LLC Agreement") which declared the mandatory redemption date for all Series A Preferred Units in cash to one year following the expiration of the credit agreement (as may be further amended, restated, supplemented, modified or replaced from time to time) which at that time was set to mature on September 28, 2023.

In accordance with ASC 480 Distinguishing Liabilities From Equity, equity securities are required to be classified outside of permanent equity in temporary equity if they are redeemable or may become redeemable for cash or other assets. As the Company was not considered to have sole control over the contractually mandated redemption during the year ended September 30, 2020 based on the set redemption in 2024, the Series A Preferred Units were classified as mezzanine equity until they were converted into common units, as discussed below.

Immediately prior to the closing of the Merger on February 26, 2021 and in accordance with the Merger Agreement, REP LLC converted each issued and outstanding Series A Preferred Unit into one common unit and paid the holders of REP LLC Series A Preferred Units a cash payment equal to the amount of any unpaid dividends accruing between October 1, 2020 and February 26, 2021 in accordance with the Fourth LLC Agreement. The Company converted 511,695 Series A Preferred Units with a value of $61.2 million to common units in accordance with the Fourth LLC Agreement and Merger Agreement. Additionally, the cash payment of any unpaid dividends accrued between October 1, 2020 and February 26, 2021 was $1.5 million on 511,695 Series A Preferred Units.

The tables below summarize the preferred unit activity during the year ended September 30, 2021:

	Units	Amount
		(In thousands)
Balance, September 30, 2020	504,168	$ 60,292
Dividends paid in kind	7,527	904
Units converted to common units	(511,695)	(61,196)
Balance, September 30, 2021	—	$ —

After the closing of the Merger, the Company's authorized capital stock includes 25 million shares of preferred stock with a par value of $0.0001 per share, of which no shares were issued and outstanding as of December 31, 2021 or September 30, 2021.

(12) Income Taxes

REP LLC was organized as a limited liability company and treated as a flow-through entity for federal income tax purposes. As such, taxable income and any related tax credits were passed through to its members and included in their tax returns, even though such taxable income or tax credits may not have been distributed. In connection with the closing of the Merger, the Company's tax status changed from a limited liability company to a C-corporation. As a result, the Company is responsible for federal and state income taxes and must record deferred tax assets and liabilities for the tax effects of any temporary differences that exist on the date of the change. When push down accounting does not apply as part of a business combination, U.S. GAAP requires the effect of the change in tax status to be recognized in the financial statements and the effect is included in income (loss) from continuing operations. Upon consummation of the Merger, the Company established a $13.6 million provision for deferred income taxes with the conversion to a C-corporation. Accordingly, a provision for federal and state corporate income taxes has been made for the operations of REP LLC only from February 27, 2021 through December 31, 2021 in the accompanying consolidated financial statements.

The components of the Company's provision for income taxes from continuing operations are as follows:

	Three Months Ended December 31,	
	2021	2020
	(In thousands)	
Current income tax expense:		
Federal	$ —	$ —
State	113	—
Total current income tax expense	$ 113	$ —
Deferred income tax expense (benefit):		
Federal	$ 5,669	$ —
State	87	(515)
Total deferred income tax expense (benefit)	$ 5,756	$ (515)
Total income tax expense (benefit)	$ 5,869	$ (515)

Deferred tax assets and liabilities are the result of temporary differences between the financial statement carrying values and the tax bases of assets and liabilities. The Company's net deferred tax position is as follows:

	December 31, 2021	September 30, 2021
	(In thousands)	
Deferred tax assets		
Non-cash gain on derivatives	$ 10,286	$ 11,006
Intangibles	215	222
Inventory	23	23
Share-based compensation	690	480
Accruals and other	558	578
Net operating loss	3,172	5,422
Total deferred tax assets	14,944	17,731
Oil and natural gas assets	(32,154)	(29,161)
Other fixed assets	(174)	(198)
Total deferred tax liabilities	(32,328)	(29,359)
Net deferred tax liabilities	$ (17,384)	$ (11,628)

A reconciliation of the statutory federal income tax rate to the Company's effective income tax rate is as follows:

	Three Months Ended December 31,	
	2021	2020
Tax at statutory rate	21.0 %	21.0 %
Nondeductible compensation	0.1 %	— %
Share-based compensation	(0.3)%	— %
State income taxes, net of federal benefit	0.7 %	2.0 %
Income subject to taxation by REP LLC's unitholders	— %	(21.0)%
Effective income tax rate	21.5 %	2.0 %

The Company's federal income tax returns for the years subsequent to December 31, 2018 remain subject to examination. The Company's income tax returns in major state income tax jurisdictions remain subject to examination for various periods subsequent to December 31, 2017. The Company currently believes that all other significant filing positions are highly certain and that all of its other significant income tax positions and deductions would be sustained under audit or the final resolution would not have a material effect on the consolidated financial statements. Therefore, the Company has not established any significant reserves for uncertain tax positions.

Section 382 of the Internal Revenue Code limits the utilization of U.S. net operating loss ("NOL") carryforwards following a change in control. The Merger caused a stock ownership change for purposes of Section 382 which is subject to an approximate annual limit. The Company has federal net operating losses subject to the annual Section 382 limit of $13.4 million of which $4.6 million will expire beginning in 2022 with the remaining $8.8 million of the NOL's not expiring. Additionally, the Company has approximately $1.7 million of federal net operating losses generated after the Merger that are not limited by Section 382 and are not subject to expiration. We believe it is more likely than not the tax benefit of these net operating losses will be fully realized, as such no valuation allowance has been recorded. The deferred tax assets for the net operating losses are presented net with deferred tax liabilities, which primarily consist of book and tax depreciation differences.

(13) Net Income (Loss) Per Share/Unit

Net income (loss) per share/unit is calculated using a retroactive application of the Exchange Ratio and the one-for-twelve reverse stock split that occurred in conjunction with the Merger. The Company calculated net income or loss per share/unit using the treasury stock method.

The table below sets forth the computation of basic and diluted net income (loss) per share/unit for the three months ended December 31, 2021 and 2020:

	Three Months Ended December 31, 2021	Three Months Ended December 31, 2020
	(In thousands, except per share/unit)	
Net income (loss) - Diluted	$ 21,398	$ (7,941)
Less: Dividends on preferred units	—	(917)
Net income (loss) attributable to common shareholders/unitholders - Basic(1)	$ 21,398	$ (8,858)
Basic weighted-average common shares/units outstanding	19,470	12,469
Effecting of dilutive securities:		
Restricted shares/units	99	—
Diluted weighted-average common shares/units outstanding	19,569	12,469
Basic net income (loss) per common share/unit	$ 1.10	$ (0.71)
Diluted net income (loss) per common share/unit	$ 1.09	$ (0.71)

(1) Used in basic and diluted net loss per share calculation for December 31, 2020 since the Company was in a net loss position.

For the three months ended December 31, 2021 and 2020, the following shares/units were excluded from the calculation of diluted net income (loss) per share/unit due to their anti-dilutive effect:

	Three Months Ended December 31, 2021	Three Months Ended December 31, 2020
	(In thousands)	
Series A preferred units	—	4,170
Restricted shares/units	268	281

(14) Commitments and Contingencies

Legal Matters

The Company has been named as a defendant in an action commenced on October 25, 2021 in United States Bankruptcy Court for the Northern District of Texas, Dallas Division, by the Chapter 7 Trustee for the Hoactzin Bankruptcy. The Company was served with this lawsuit on or about December 7, 2021. The complaint alleges that in October of 2018, one year prior to the Hoactzin bankruptcy filing in October of 2019, Peter Salas ("Salas"), Chairman of the Board of Tengasco during the period of the purported fraudulent transfers, caused Hoactzin to transfer its working interests in certain wells on its Kansas acreage (the “Kansas Working Interests”) to the Company for an amount the complaint alleges was purportedly less than the reasonable equivalent value of such Kansas Working Interests. The complaint includes avoidance actions and other causes of action in connection with the transfer of the Kansas Working Interests, as well as other causes of action alleged related to certain transactions to which the Company was not a party.

The complaint also alleges that Salas, Dolphin Direct Equity Partners, L.P. ("DDEP"), an entity substantially owned by Salas, and the Company are jointly and severally liable for the damages incurred by Hoactzin. In connection with the Company’s merger in February 2021, Salas resigned his position from the Company’s Board and no longer holds any position as an officer or director of the Company. On April 2, 2021, the Company closed on the sale of all the assets it held in Kansas (of which the Kansas Working Interests were a small part) to a third party for an agreed upon purchase price of $3.3 million.

The Company believes that the claims are without merit and is asserting a vigorous defense. The Company has filed an answer denying the allegations. The parties are conducting discovery.

The Company did not recognize any material liability as of December 31, 2021 and September 30, 2021. The Company's assessment of probability and/or estimates of liabilities are based on information known about the pending legal matters and its experience in contesting, litigating, and settling similar matters. Although actual amounts could differ from management's estimates, none of the actions are believed by management to involve future amounts that would be material to the Company's financial position or results of operations, or liquidity after consideration of recorded accruals. Management does not expect that the losses from any litigation matters or claims that are reasonably possible to occur will have a material adverse effect on the Company's financial position, results of operations, or liquidity.

Environmental Matters

The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. These laws, which are often changing, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. The Company had no environmental liabilities as of December 31, 2021 or September 30, 2021.

Contractual Commitments

In July 2021, as part of a planned expansion of the primary gas processing plant owned by the Company's primary midstream partner, Stakeholder Midstream LLC ("Stakeholder"), the Company committed to annually drill, complete and connect a minimum number of wells or deliver an annual target volume to Stakeholder's gathering system. While the minimum number of wells is below our planned development activity, there are financial penalties if the minimum activity levels are not met. The annual well or volume target is for each of five years beginning January 2022. The additional capacity from the gas processing plant expansion is expected to lead to increased natural gas sales and decreased gas flaring for the Company.

In August 2021, the Company entered into a purchase agreement for supplies for its EOR project. Under the agreement, the Company has remaining commitments totaling approximately $0.8 million and $2.6 million to purchase supplies by January 2022 and April 2022, respectively.

On October 7, 2021, the Company executed two agreements related to its EOR project. The first agreement is a CO_2 purchase agreement with Kinder Morgan CO_2 Company, LLC and the second agreement is a connection agreement that also established a delivery point for the purchased CO_2 with the Cortez Pipeline Company.

(15) Subsequent Events

Dividend Declarations. On January 12, 2022, the Board of Directors of the Company declared a cash dividend of $0.31 per share of common stock, payable on February 9, 2022 to its shareholders of record at the close of business on January 26, 2022.

On April 11, 2022, the Board of Directors of the Company declared a cash dividend of $0.31 per share of common stock, payable on May 5, 2022 to its shareholders of record at the close of business on April 21, 2022.

On July 11, 2022, the Board of Directors of the Company declared a cash dividend of $0.31 per share of common stock, payable on August 8, 2022 to its shareholders of record at the close of business on July 25, 2022.

Related Party Transaction. On January 25, 2022, the Company and di Santo Law PLLC, a law firm owned by a member of our Board of Directors, entered into an engagement letter that provides a monthly fixed fee in exchange for general corporate legal services. The agreement has an initial term of one year and provides for a monthly cash payment of $30,000 and an aggregate one-time grant of 10,500 shares of restricted stock that will vest in four equal installments at the end of each quarter in calendar year 2022.

Purchase Agreements. On March 25, 2022, the Company executed a purchase order for facility and support equipment for its EOR project. Under the order, the Company has remaining commitments totaling approximately $2.0 million as of the date of this Transition Report, and the equipment will be delivered within 29 weeks of executing the purchase order.

On April 22, 2022, the Company entered into a purchase agreement for pipe primarily related to its 2023 drilling program. Under the agreement, the Company has commitments to purchase approximately $10.6 million of pipe by December 2022.

Credit Facility Amendment. On April 29, 2022, the Company amended its Credit Agreement to, among other things, increase the borrowing base from $175 million to $200 million, extend the maturing date to April 2026, replace LIBOR with the SOFR and changed the requirements for hedging to be based on utilization of the borrowing base and the Company's leverage ratio ranging between 0% and 50% (depending on the borrowing base utilization percentage and leverage ratio as of the hedge evaluation date) of its proved developed producing volumes.

(16) Supplemental Information on Oil and Natural Gas Operations (Unaudited)

Capitalized Costs

Capitalized costs include the cost of properties, equipment and facilities for oil and natural gas producing activities. Capitalized costs for proved properties include costs for oil and natural gas leaseholds where proved reserves have been identified, development wells and related equipment and facilities, including development wells in progress.

Capitalized costs for unproved properties include costs for acquiring oil and natural gas leaseholds where no proved reserves have been identified, including costs of exploratory wells that are in the process of drilling or in active completion, and costs of exploratory wells suspended or waiting on completion. For a summary of these costs, please refer to Note 5 – Oil and Natural Gas Properties.

Costs Incurred for Property Acquisition, Exploration and Development

Amounts reported as costs incurred include both capitalized costs and costs charged to expense when incurred for oil and natural gas property acquisition, exploration and development activities. Costs incurred also include new ARO established in the current year as well as increases or decreases to ARO resulting from changes to cost estimates during the year. Exploration costs presented below include the costs of drilling and equipping successful and unsuccessful exploration wells during the year, geological and geophysical expenses and the costs of retaining undeveloped leaseholds. Development costs include the costs of drilling and equipping development wells and construction of related production facilities.

The following summarizes the costs incurred for oil and natural gas property acquisition, exploration and development activities for the three months ended December 31, 2021 and year ended September 30, 2021:

	December 31, 2021	September 30, 2021
	(In thousands)	
Acquisition of properties		
Proved	$ 67	$ 74
Unproved	193	1,562
Exploration costs	—	7,993
Development costs	20,348	59,948
Total costs incurred	$ 20,608	$ 69,577

SUPPLEMENTAL OIL AND GAS INFORMATION - (Continued)
(Unaudited)

Results of Operations

The following table includes revenues and expenses associated with the Company's oil and natural gas producing activities. The amounts do not include any allocation of the Company's interest costs or general corporate overhead. Therefore, the following schedule is not necessarily indicative of the contribution of net earnings of the Company's oil and natural gas operations.

	Three Months Ended December 31, 2021	Year Ended September 30, 2021
	(In thousands)	
Oil, natural gas and NGL sales	$ 56,650	$ 148,636
Lease operating expenses	7,419	21,975
Production and ad valorem taxes	3,005	8,636
Exploration costs	611	9,566
Depletion, accretion and amortization	6,742	25,347
Results of operations	38,873	83,112
Income tax expense (1)	(8,393)	(13,505)
Results of operations, net of income tax expense	$ 30,480	$ 69,607

(1) Subsequent to the Closing Date of the Merger, the statutory combined federal and state tax rate of 21.59% is used for the three months ended December 31, 2021 and year ended September 30, 2021.

Oil, Natural Gas and NGL Quantities

Our reserves, as of December 31, 2021 and September 30, 2021, were prepared by Netherland, Sewell & Associates, Inc. and are presented below. All reserves are located within the continental United States. Proved oil, natural gas and NGL reserves are the estimated quantities of oil, natural gas and NGLs that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions existing at the time the estimate is made. Proved developed oil, natural gas and NGL reserves are proved reserves that can be expected to be recovered through existing wells and equipment in place and under operating methods being utilized at the time the estimates were made. A variety of methodologies are used to determine our proved reserve estimates. The principal methodologies employed are decline curve analysis and analogy. Some combination of these methods is used to determine reserve estimates in substantially all of our fields. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established proved producing oil and natural gas properties. Accordingly, these estimates are expected to change as future information becomes available.

SUPPLEMENTAL OIL AND GAS INFORMATION - (Continued)
(Unaudited)

The following table sets forth information for the three months ended December 31, 2021 and year ended September 30, 2021 with respect to changes in the Company's proved (i.e., proved developed and undeveloped) reserves:

	Oil (MBbl)	Natural Gas (MMcf)	NGLs (MBbl)	Total (MBoe)
September 30, 2020	37,158	53,683	10,681	56,787
Extensions and discoveries	9,308	12,089	2,436	13,759
Revisions	2,138	12,850	492	4,772
Production	(2,341)	(2,603)	(380)	(3,155)
September 30, 2021	46,263	76,019	13,229	72,163
Extensions and discoveries	1,328	1,961	371	2,026
Revisions	99	350	(24)	133
Production	(669)	(844)	(105)	(915)
December 31, 2021	47,021	77,486	13,471	73,407
Proved Developed Reserves, Included Above				
September 30, 2020	19,149	31,137	5,847	30,186
September 30, 2021	26,170	46,173	7,650	41,516
December 31, 2021	27,096	47,974	7,949	43,041
Proved Undeveloped Reserves, Included Above				
September 30, 2020	18,009	22,546	4,834	26,601
September 30, 2021	20,093	29,846	5,579	30,647
December 31, 2021	19,925	29,512	5,522	30,366

As of December 31, 2021, reserves were comprised of 64.1% oil, 17.6% natural gas and 18.3% NGL. December 31, 2021 proved reserves were estimated based on prices of $64.60 per Bbl of oil, $1.65 per Mcf of natural gas and $13.75 per Bbl of NGL. Prices used in the December 31, 2021 reserve report are based on the twelve month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January 2021 through December 2021. For oil and NGL volumes, the average WTI spot price of $66.55 per Bbl is adjusted for quality, transportation fees, and market differentials. The fees associated with the transportation contract are included as a deduction to oil revenue. For gas volumes, the average Henry Hub spot price of $3.60 per MMBtu is adjusted for energy content, transportation fees and market differentials.

As of September 30, 2021, reserves were comprised of 64.1% oil, 17.6% natural gas and 18.3% NGL. September 30, 2021 proved reserves were estimated based on prices of $55.73 per Bbl of oil, $0.99 per Mcf of natural gas and $9.83 per Bbl of NGL. Prices used in the September 30, 2021 reserve report are based on the twelve month unweighted arithmetic average of the first-day-of-the-month price for each month in the period October 2020 through September 2021. For oil and NGL volumes, the average WTI spot price of $57.64 per Bbl is adjusted for quality, transportation fees, and market differentials. The fees associated with the transportation contract are included as a deduction to oil revenue. For gas volumes, the average Henry Hub spot price of $2.94 per MMBtu is adjusted for energy content, transportation fees and market differentials.

For the three months ended December 31, 2021, the Company had net upward revisions of previous estimates of 133 MBoe. These revisions are primarily the result of increases in pricing. The Company had extensions and discoveries to proved developed and proved non-developed reserves of 2,026 MBoe as a result of drilling successful wells that were previously classified as unproved locations. During the three months ended December 31, 2021, the Company did not purchase any additional reserves.

For the year ended September 30, 2021, the Company had upward revisions of previous estimates of 4,772 MBoe. These revisions are primarily the result of increases in pricing. The Company had extensions and discoveries to proved developed and proved non-developed reserves of 13,759 MBoe which consisted of 6,564 MBoe as a result of drilling successful wells that were previously classified as unproved locations, and the addition to proved undeveloped of 7,195 MBoe as a result of drilling successful wells offsetting locations that were previously unproven locations. During the year ended September 30, 2021, the Company did not purchase any additional reserves.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil, Natural Gas and NGL Reserves

The Company follows the guidelines prescribed in ASC Topic 932 Extractive Activities – Oil and Gas for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. The following summarizes the policies used in the preparation of the accompanying oil, natural gas and NGL reserve disclosures, standardized measures of discounted future net cash flows from proved oil, natural gas and NGL reserves and the reconciliations of standardized measures from year to year.

The standardized measure of discounted future net cash flows from production of proved reserves was developed as follows: (i) estimates are made of quantities of proved reserves and future periods during which they are expected to be produced based on year-end economic conditions; (ii) estimated future cash flows are compiled by applying the twelve month average of the first of the month prices of crude oil and natural gas relating to the Company's proved reserves to the period end quantities of those reserves for reserves; (iii) future cash flows are reduced by estimated production costs, costs to develop and produce the proved reserves and abandonment costs, all based on period end economic conditions, plus Company overhead incurred; (iv) future income tax expenses are based on year-end statutory tax rates giving effect to the remaining tax basis in the oil and natural gas properties, other deductions, credits and allowances relating to the Company's proved oil and natural gas reserves; and, (v) future net cash flows are discounted to present value by applying a discount rate of 10%.

The assumptions used to compute the standardized measure are those prescribed by the FASB and the SEC. These assumptions do not necessarily reflect the Company's expectations of actual revenues to be derived from those reserves, nor their present value. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations, since these reserve quantity estimates are the basis for the valuation process. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established proved producing oil and natural gas properties. The standardized measure of discounted future net cash flows does not purport, nor should it be interpreted, to present the fair value of the Company's oil and natural gas reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs and a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

The following summary sets forth the Company's future net cash flows relating to proved oil, natural gas and NGL reserves based on the standardized measure prescribed in ASC Topic 932:

	December 31, 2021	September 30, 2021
	(In thousands)	
Future crude oil, natural gas and NGLs sales [(1)] [(2)]	$ 3,350,506	$ 2,783,910
Future production costs	(912,468)	(839,167)
Future development costs	(216,138)	(218,765)
Future income tax expense	(436,829)	(324,487)
Future net cash flows	1,785,071	1,401,491
10% annual discount	(1,081,602)	(848,555)
Standardized measure of discounted future net cash flows	$ 703,469	$ 552,936

(1) December 31, 2021 proved reserves were derived based on prices of $64.60 of oil, $1.65 of natural gas and $13.75 of NGL.
(2) September 30, 2021 proved reserves were derived based on prices of $55.73 of oil, $0.99 of natural gas and $9.83 of NGL.

SUPPLEMENTAL OIL AND GAS INFORMATION - (Continued)
(Unaudited)

Principal sources of change in the Standardized Measure are shown below:

	Three Months Ended December 31, 2021	Year Ended September 30, 2021
	(In thousands)	
Balance, beginning of period	$ 552,936	$ 302,338
Sales of crude oil, natural gas and NGLs, net	(46,226)	(118,030)
Net change in prices and production costs	194,596	237,475
Net changes in future development costs	1,267	(18,856)
Extensions and discoveries	35,111	144,392
Revisions of previous quantity estimates	(536)	50,283
Previously estimated development costs incurred	4,182	12,844
Net change in income taxes	(47,881)	(124,625)
Accretion of discount	17,018	30,551
Other	(6,998)	36,564
Balance, end of period	$ 703,469	$ 552,936

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

The following discussion and analysis of the Company's financial condition and results of operations and other sections of this Transition Report should be read in conjunction with the Company's consolidated financial statements and related notes thereto presented in this report. The following discussion contains "forward-looking statements" that reflect the Company's future plans, estimates, beliefs and expected performance. The Company's actual results could differ materially from those discussed in these forward-looking statements. See "Cautionary Statement Regarding Forward-Looking Statements" and "Part II. Item 1A. Risk Factors".

Overview

We operate in the upstream segment of the oil and natural gas industry and are focused on steadily growing conventional reserves, production and cash flow through the acquisition, exploration, development and production of oil, natural gas and NGLs primarily in the Permian Basin in West Texas. The Company's activities are primarily focused on the San Andres Formation, a shelf margin deposit on the Central Basin Platform and Northwest Shelf. We intend to continue to develop our reserves and increase production through development drilling and exploration activities on our multi-year inventory of identified potential drilling locations and through acquisitions that meet our strategic and financial objectives.

Financial and Operating Highlights

Financial and operating results reflect the following:

- Increased total net equivalent production by 31% to 9.9 MBoe/d for the three months ended December 31, 2021, as compared to the same period in 2020
- During the three months ended December 31, 2021, 5 gross (4.1 net) horizontal wells brought online to production
- Realized average combined price on production sold of $61.94 per Boe, before derivative settlements, during the three months ended December 31, 2021, including $75.67 per barrel for oil
- Generated cash flow from operations of $21.7 million for the three months ended December 31, 2021
- Total accrued capital expenditures of $20.7 million for the three months ended December 31, 2021
- Paid cash dividends on common shares of $6.1 million during the three months ended December 31, 2021, and announced latest dividend of $0.31 per share with a record date of January 26, 2022, which was paid on February 9, 2022, for a total of $6.1 million
- Exited calendar year 2021 with $8.3 million in cash and $65.0 million drawn on our revolving credit facility

Recent Developments

Fiscal Year Change

On August 16, 2022, the Company's Board of Directors (the "Board") acting by written consent resolved to amend and restate the Company's Second Amended and Restated Bylaws to change the Company's fiscal year period from October 1st through September 30th each year to January 1st through December 31st each year commencing with the 2022 calendar year (the "Bylaws Restatement"). On August 19, 2022, the holders of approximately 75% of our outstanding Common Stock acting by written consent approved Bylaws Restatement and adopted the Third Amended and Restated Bylaws, which are included hereto as Exhibit 3.3. In accordance with Rule 14c-2 under the Exchange Act, the aforementioned actions taken by written consent became effective on September 23, 2022. As a result, the Company's 2022 fiscal year will now be the period from January 1, 2022 to December 31, 2022.

Results of Operations

Comparison for the three months ended December 31, 2021 and 2020

The following table sets forth selected operating data for the three months ended December 31, 2021 and 2020:

	Three Months Ended December 31,	
	2021	2020
Revenues (in thousands):		
Oil sales	$ 50,623	$ 22,107
Natural gas sales	2,705	119
Natural gas liquids sales	3,322	188
Oil and natural gas sales, net	$ 56,650	$ 22,414
Production Data, net:		
Oil (MBbls)	669	547
Natural gas (MMcf)	844	461
Natural gas liquids (MBbls)	105	74
Total (MBoe)	915	698
Daily combined volumes (Boe/d)	9,940	7,583
Daily oil volumes (Bbls/d)	7,271	5,945
Average Realized Prices:		
Oil ($ per Bbl)	$ 75.67	$ 40.41
Natural gas ($ per Mcf)	3.20	0.26
Natural gas liquids ($ per Bbl)	31.64	2.54
Combined ($ per Boe)	$ 61.94	$ 32.12
Average Realized Prices, including derivative settlements:[(1)]		
Oil ($ per Bbl)	$ 54.05	$ 49.87
Natural gas ($ per MMBtu)	1.37	0.26
Natural gas liquids ($ per Bbl)	31.64	2.54
Combined ($ per Boe)	$ 44.43	$ 39.53

(1) The Company's calculation of the effects of derivative settlements includes gains (losses) on the settlement of its commodity derivative contracts. These gains (losses) are included under other income and expense on the Company's consolidated statements of operations.

Oil and Natural Gas Revenues

Our revenues are derived from the sale of our oil and natural gas production, including the sale of NGLs that are extracted from our natural gas during processing. Revenues from product sales are a function of the volumes produced, product quality, market prices, and gas Btu content. Our revenues from oil, natural gas and NGL sales do not include the effects of derivatives. 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 Company's total oil and natural gas revenue, net increased $34.2 million, or 153%, for the three months ended December 31, 2021 compared to the same period in 2020. The Company's realized average combined price on its production for the three months ended December 31, 2021 increased by $29.82 or 93%, respectively, compared to the same period of 2020.

Oil revenues

- For the three months ended December 31, 2021, oil revenues increased by $28.5 million, or 129%, compared to the same period in 2020. Of the increase, $23.6 million was attributable to an increase in our realized price and $4.9 million was attributable to an increase in volume. Volumes increased by 22% while prices increased by 87% compared to the same period in 2020.
- Oil volumes increased during the three months ended December 31, 2021 due to production from new wells and workovers performed on existing wells. During the three months ended December 31, 2021, we brought online 5 new gross (4.1 net) wells.

Natural gas revenues

- For the three months ended December 31, 2021, natural gas revenues increased by $2.6 million, compared to the same period in 2020, to $2.7 million from $0.1 million. Volumes increased by 83% and realized prices increased by $2.94 per Mcf from realized prices in 2020.
- Natural gas sales volumes increased during the three months ended December 31, 2021 due to increased production from new wells brought online and increased gas processing capacity available from the Company's midstream gathering and processing partner.

Natural gas liquids revenues

- For the three months ended December 31, 2021, NGL revenues increased by $3.1 million, compared to the same period in 2020, to $3.3 million from $0.2 million. Volumes increased by 42% and realized prices increased by $29.10 per Bbl from realized prices in 2020.
- NGL sales volumes increased during the three months ended December 31, 2021 due to increased production from new wells brought online and increased gas processing capacity available from the Company's midstream gathering and processing partner.

Contract Services - Related Party Revenue

The following tables present the Company's revenue and costs associated with its related party transactions:

	Three Months Ended December 31,	
	2021	2020
	(In thousands)	
Contract services – related parties(1)	$ 600	$ 600
Cost of contract services - related parties(2)	150	148
Gross profit - related parties	$ 450	$ 452

(1) The Company's contract services – related parties revenue is derived from master services agreements with related parties to provide certain administrative support services.
(2) The Company's cost of contract services - related parties represents costs specifically attributable to the master service agreements the Company has in place with the respective related parties.

The following table presents the Company's operating costs and expenses and other (income) expenses:

	Three Months Ended December 31,	
	2021	2020
Costs and Expenses:	(In thousands)	
Lease operating expenses	$ 7,419	$ 4,568
Production and ad valorem taxes	$ 3,005	$ 1,289
Exploration costs	$ 611	$ 424
Depletion, depreciation, amortization and accretion	$ 6,867	$ 5,990
Administrative costs	$ 3,633	$ 2,445
Equity-based compensation	951	413
General and administrative expense	$ 4,584	$ 2,858
Transaction costs	$ 1,258	$ 1,049
Interest expense	$ 896	$ 1,235
Loss on derivatives	$ 5,193	$ 13,909
Income tax expense (benefit)	$ 5,869	$ (515)

Lease Operating Expenses

Lease operating expenses ("LOE") are the costs incurred in the operation and maintenance of producing properties. Expenses for compression, direct labor, saltwater disposal and materials and supplies comprise the most significant portion of our lease operating expenses. Certain operating cost components, such as direct labor and materials and supplies, generally remain relatively fixed across broad production volume ranges, but can fluctuate depending on activities performed during a specific period. For instance, repairs to our pumping equipment or surface facilities or subsurface maintenance result in increased production expenses in periods during which they are performed. Certain operating cost components, such as compression and saltwater disposal associated with completion water, are variable and increase or decrease as hydrocarbon production levels and the volume of completion water disposal increases or decreases.

The Company’s LOE increased by $2.9 million for the three months ended December 31, 2021 compared to the same period in 2020. For the three months ended December 31, 2021, $1.4 million of the increase was attributable to an increase in variable LOE costs as production volumes increased and $1.1 million of the increase was due to higher workover expense.

Production and Ad Valorem Tax Expense

Production taxes are paid on produced oil, natural gas and NGLs based on a percentage of revenues at fixed rates established by federal, state or local taxing authorities. In general, the production taxes we pay correlate to changes in our oil, natural gas and NGL revenues. We are also subject to ad valorem taxes in the counties where our production is located. Ad valorem taxes are generally based on the valuation of our oil and natural gas properties, which also trend with oil and natural gas prices and vary across the different counties in which we operate. Production and ad valorem taxes increased by $1.7 million for the three months ended December 31, 2021 compared to the same period in 2020, primarily due to increases in our production sold resulting from additional wells brought online, workovers performed on existing wells that increased production and significantly higher commodity prices. Also contributing to the increase is higher ad valorem taxes based on the increase in property values during the three months ended December 31, 2021.

Exploration Expense

Exploration expense, which consists of expiration of unproved leasehold and geological and geophysical costs that include seismic survey costs, increased by $0.2 million, or 44%, for the three months ended December 31, 2021, as compared to the same period in 2020. For the three months ended December 31, 2021, the Company incurred higher exploration expense compared to the same period in 2020 primarily driven by higher acreage expirations in New Mexico.

The following table presents exploration expense by area for the three months ended December 31, 2021 and 2020:

	Three Months Ended December 31,	
	2021	2020
	(In thousands, except acreage data)	
Exploration expense[1]	$ 588	$ 424
Geological and geophysical costs	23	—
Total exploration expense	$ 611	$ 424
Expired net acres - Texas	91	99
Expired net acres - New Mexico	1,146	905
Net acres renewed after expiration[2]	89	100

(1) As of December 31, 2021, exploration expense includes $187 thousand and $401 thousand related to expiration of unproved leasehold costs in Texas and New Mexico, respectively. As of December 31, 2020, exploration expense includes $225 thousand and $199 thousand related to expiration of unproved leasehold costs in Texas and New Mexico, respectively.
(2) The Company did not renew any net acreage after expiration in New Mexico during the three months ended December 31, 2021 and 2020.

Depletion, Depreciation, Amortization and Accretion Expense

Depreciation, depletion, and amortization is the systematic expensing of the capitalized costs incurred to acquire, explore and develop oil, natural gas and NGLs. All costs incurred in the acquisition, exploration and development of properties (excluding costs of surrendered and abandoned leaseholds, delay lease rentals, dry holes and overhead related to exploration activities) are capitalized. Capitalized costs are depleted using the units of production method.

Accretion expense relates to ARO. We record the fair value of the legal liability for ARO in the period in which the liability is incurred (at the time the wells are drilled or acquired) at the asset's inception, with the offsetting increase to property cost. The liability accretes each period until it is settled or the well is sold, at which time the liability is removed.

Depletion, depreciation, amortization and accretion expense increased by $0.9 million for the three months ended December 31, 2021 compared to the same period for 2020. The increase for the three months ended December 31, 2021 was due to higher production, partially offset by a lower depletion rate. The depletion rate is a function of capitalized cost and related underlying reserves. The lower depletion rate was primarily driven by an increase in reserves as a result of improved commodity prices.

General and Administrative Expense ("G&A")

G&A expenses include corporate overhead such as payroll and benefits for our corporate staff, equity-based compensation expense, office rent for our headquarters, audit and other fees for professional services and legal compliance. G&A expenses are reported net of overhead recoveries from other owners in properties operated by us.

Total G&A expense increased by $1.7 million, for the three months ended December 31, 2021, compared to the same period for 2020. Administrative costs, which includes payroll, benefits and non-payroll costs, increased by $1.2 million, for the three months ended December 31, 2021, compared to the same period for 2020. The increase in administrative costs was primarily attributable to increased professional services, insurance, technology and investor relations costs. Equity compensation expense increased by $0.5 million for the three months ended December 31, 2021, compared to the same period in 2020. The increase is primarily attributable to restricted shares awarded to employees in October 2021 and restricted shares awarded to certain employees following completion of the Merger.

Interest Expense

Interest expense was $0.9 million and $1.2 million for the three months ended December 31, 2021 and 2020, respectively. Interest expense decreased due to a lower outstanding average balance on the Company's revolving credit facility during the three months ended December 31, 2021 when compared to the same period for 2020.

Gain/Loss on Derivatives

The Company recognizes settlements and changes in the fair value of its derivative contracts as a single component within other income (expenses) on its consolidated statements of operations. We have oil and natural gas derivative contracts, including fixed price swaps, basis swaps and collars, that settle against various indices. The following table presents the components of the Company's gain (loss) on derivatives for the three months ended December 31, 2021 and 2020:

	Three Months Ended December 31,	
	2021	2020
	(In thousands)	
Settlements on derivatives	$ (16,014)	$ 5,173
Non-cash gain (loss) on derivatives	10,821	(19,082)
Loss on derivatives	$ (5,193)	$ (13,909)

Our earnings are affected by the changes in value of our derivatives portfolio between periods and the related cash received or paid upon settlement of our derivatives. To the extent the future commodity price outlook declines between periods, we will have mark-to-market gains; while to the extent future commodity price outlook increases between measurement periods, we will have mark-to-market losses.

Income Tax Expense

The Company became a taxable entity as a result of its Merger with Tengasco on February 26, 2021. See further discussion in Note 4 - Acquisitions and Divestitures to the Company's consolidated financial statements included herein. While REP LLC was organized as a limited liability company, taxable income passed through to its unit holders. Accordingly, a provision for federal and state corporate income taxes has been made for the operations of REP LLC only from February 27, 2021 through December 31, 2021 in the accompanying consolidated financial statements. Deferred income taxes are provided to reflect the future tax consequences or benefits of differences between the tax basis of assets and liabilities and their reported amounts in the financial statements using enacted tax rates. Upon consummation of the Merger, the Company established a $13.6 million provision for deferred income taxes with the conversion to a C-corporation. The majority of this deferred tax liability was established by a change in tax status which primarily was attributable to the oil and natural gas properties. See Note 11 - Income Taxes to the Company's consolidated financial statements included herein for further discussion of income taxes.

	Three Months Ended December 31,	
	2021	2020
	(In thousands)	
Current expense	$ 113	$ —
Deferred expense (benefit)	5,756	(515)
Total expense (benefit)	$ 5,869	$ (515)
Effective income tax rate	21.5 %	2.0 %

Liquidity and Capital Resources

The business of exploring for, developing and producing oil and natural gas is capital intensive. Because oil, natural gas and NGL reserves are a depleting resource, like all upstream operators, we must make capital investments to grow and even sustain production. The Company’s principal liquidity requirements are to finance its operations, fund capital expenditures and acquisitions, make cash distributions and satisfy any indebtedness obligations. Cash flows are subject to a number of variables, including the level of oil and natural gas production and prices, and the significant capital expenditures required to more fully develop the Company’s oil and natural gas properties. Historically, our primary sources of capital funding and liquidity have been our cash on hand, cash flow from operations and borrowings under our revolving credit facility. At times and as needed, we may also issue debt or equity securities, including through transactions under our shelf registration statement filed with the SEC. We estimate the combination of the sources of capital discussed above will continue to be adequate to meet our short and long-term liquidity needs.

Cash on hand and operating cash flow can be subject to fluctuations due to trends and uncertainties that are beyond our control. Likewise, our ability to issue equity and our ability to obtain credit facilities on favorable terms may be impacted by a variety of market factors as well as fluctuations in our results of operations. Subsequent to the period ending December 31, 2021, the Company's natural gas and NGL sales were negatively impacted due to its primary midstream gas gathering and processing counterparty curtailing volume capacity as work continues on their overall capacity expansion project. With the expansion project being fully commissioned in July 2022, the Company expects to benefit from an increase in production capacity. The Company is not currently aware of additional scheduled curtailments; however, the Company may continue to experience periodic curtailments on natural gas produced in excess of our contractual processing capacity. For further discussion of risks related to our liquidity and capital resources, see "Item 1A. Risk Factors."

Working Capital

Working capital is the difference in our current assets and our current liabilities. Working capital is an indication of liquidity and potential need for short-term funding. The change in our working capital requirements is driven generally by changes in accounts receivable, accounts payable, commodity prices, credit extended to, and the timing of collections from customers, the level and timing of spending for expansion activity, and the timing of debt maturities. As of December 31, 2021, we had a working capital deficit of $32.8 million compared to working capital deficit of $46.9 million as of September 30, 2021. The working capital deficit at December 31, 2021 reflects $31.0 million in current derivative liabilities compared to $42.1 million in current derivative liabilities at September 30, 2021. We utilize our revolving credit facility and cash on hand to manage the timing of cash flows and fund short-term working capital deficits.

Cash Flows

The following table summarizes the Company’s cash flows from continuing operations:

	Three Months Ended December 31,	
	2021	2020
	(In thousands)	
Statement of Cash Flows Data from Continuing Operations:		
Net cash provided by operating activities	$ 21,727	$ 17,193
Net cash used in investing activities	$ (29,128)	$ (9,707)
Net cash used in financing activities	$ (1,349)	$ (7,269)

Operating Activities

The Company’s net cash provided by operating activities increased by $4.5 million or 26% to $21.7 million for the three months ended December 31, 2021 from $17.2 million for the same period in 2020. The increase was primarily driven by an increase in revenues of $34.2 million, partially offset by a $21.2 million decrease in net cash received for settlements of commodity derivative contracts and an increase in operating expenses of $6.0 million, which excludes non-cash expenses such as equity-based compensation, expiration of unproved leasehold costs, and depreciation, depletion, accretion, and amortization expense.

Investing Activities

The Company's cash flows used in investing activities increased by $19.4 million or 200% to $29.1 million for the three months ended December 31, 2021 from $9.7 million for the same period in 2020. The increase was primarily due to higher capital spending of $19.6 million primarily related to the Company's drilling and completion activity and EOR project in 2021.

Financing Activities

Net cash flow used in financing activities decreased by $5.9 million or 81% to $1.3 million for the three months ended December 31, 2021 from $7.3 million for the same period in 2020. During the three months ended December 31, 2021, the Company utilized proceeds from its revolving credit facility to fund capital expenditures. For the same period in 2020, the Company had a net paydown on its revolving credit facility of $3.5 million based on decreased drilling and completion activity during this period. In addition, the Company distributed an additional $2.3 million of dividends on common stock during the three months ended December 31, 2021 compared to the same period in 2020.

Revolving Credit Facility

The Company's borrowing base was $175 million with outstanding borrowings of $65 million on December 31, 2021, representing available borrowing capacity of $110 million. See further discussion in Note 9 — Revolving Credit Facility to the Company's consolidated financial statements included herein.

Distributions

For the three months ended December 31, 2021, the Company authorized and declared a quarterly dividend totaling approximately $6.1 million, with $6.0 million paid in cash and $0.1 million payable to restricted shareholders upon vesting.

Contractual Obligations

The Company has commitments with its primary midstream counterparty and has entered into purchase commitments subsequent to the three months ended December 31, 2021. See Note 14 - Commitments and Contingencies in our notes to the consolidated financial statements.

Critical Accounting Estimates

The discussion and analysis of the Company’s financial condition and results of operations are based upon the Company’s consolidated financial statements and accompanying notes included herein, which have been prepared in accordance with U.S. GAAP. The preparation of financial statements requires the Company to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. These estimates and assumptions may also affect disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period.

Changes in facts and assumptions or the discovery of new information may result in revised estimates. Actual results could differ from these estimates and assumptions used in preparation of the Company’s consolidated financial statements and it is at least reasonably possible these estimates could be revised in the near term and these revisions could be material.

Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. The Company evaluates its estimates and assumptions on a regular basis. The Company bases its estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Significant areas requiring the use of assumptions, judgments and estimates include (i) oil and natural gas reserves; (ii) cash flow estimates used in impairment testing of oil and natural gas properties; (iii) depreciation, depletion, amortization and accretion, or DD&A; (iv) ARO; (v) assigning fair value and allocating purchase price in connection with business combinations; (vi) valuation of commodity derivative instruments; (vii) income tax provisions; (viii) carrying value of goodwill; and (ix) accrued amounts. Actual results may differ from these estimates and assumptions used in preparation of the Company’s consolidated financial statements included herein.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Not applicable.

Item 4. Controls and Procedures

Disclosure Controls and Procedures

Our management establishes and maintains disclosure controls and procedures (as defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act) that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the SEC’s rules and forms. Such information is accumulated and communicated to our management, including our Chief Executive Officer (“CEO”) and Chief Financial Officer (“CFO”), as appropriate to allow timely decisions regarding required disclosure. We have evaluated the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report, with the participation of our CEO and CFO, as well as other key members of our management. Based on this evaluation, our CEO and CFO concluded that our disclosure controls and procedures were effective as of December 31, 2021.

Changes in internal control over financial reporting

There have been no changes in our internal control over financial reporting that occurred for the quarter ending December 31, 2021 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

From time to time, we may be involved in various legal proceedings and claims in the ordinary course of business. As of December 31, 2021, and through the filing date of this Transition Report, we do not believe the ultimate resolution of any such actions or potential actions of which we are currently aware will have a material effect on our consolidated financial position or results of operations.

Refer to Part I, Item 3—Legal Proceedings of Riley Permian's Annual Report on Form 10-K for the fiscal year ended September 30, 2021 and Note 14—Commitments and Contingencies in the Notes to the consolidated financial statements set forth in Part I, Item 1 of this Transition Report on Form 10-QT (which is hereby incorporated by reference herein), for a description of material legal proceedings.

Item 1A. Risk Factors

We are subject to certain risks and hazards due to the nature of the business activities we conduct. We may experience additional risks and uncertainties not currently known to us. Furthermore, as a result of developments occurring in the future, conditions that we currently deem to be immaterial may also materially and adversely affect us. Any such risk may materially and adversely affect our business, financial condition, cash flows and results of operations. Other than any risks described in this Transition Report, there have been no material changes to the risk factors described in our Annual Report on Form 10-K for the year ended September 30, 2021.

Risks Related to our Business

A Terrorist attack or armed conflict could harm our business.

Terrorist activities, anti-terrorist efforts and other armed conflicts involving the United States or other countries may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If any of these events occur, the resulting political instability and societal disruption could reduce overall demand for oil and natural gas causing a reduction in our revenues. Oil and natural gas related facilities could be direct targets of terrorist attacks, and our operations could be adversely impacted if infrastructure integral to our customers' operations is destroyed or damaged. Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

Recent regulatory restrictions on use of produced water and a moratorium on new produced water disposal wells in the Permian Basin to stem rising seismic activity and earthquakes could increase our operating costs and adversely impact our business, results of operations and financial condition.

In September 2021, the Texas Railroad Commission curtailed the amount of produced water companies were permitted to inject into some wells near Midland and Odessa in the Permian Basin, and has since indefinitely suspended some permits there and expanded the restrictions to other areas. These actions were taken in an effort to control induced seismic activity and recent increases in earthquakes in the Permian Basin, which have been linked by the United States and local seismologists to wastewater disposal in oil fields. These restrictions on the disposal of produced water and a moratorium on new produced water disposal wells could result in increased operating costs, requiring us or our service providers to truck produced water, recycle it or dispose of it by other means, all of which could be costly. We or our service providers may also need to limit disposal well volumes, disposal rates and pressures or locations, or require us or our service providers to shut down or curtail the injection of produced water into disposal wells. These factors may make drilling activity in the affected parts of the Permian Basin less economical and adversely impact our business, results of operations and financial condition.

Designation as "critical infrastructure" could subject us to additional regulation, including potential weatherization requirements.

In response to Winter Storm Uri, the February 2021 winter weather event that caused widespread power failure to Texas' power grid for several days, the Texas legislature drafted new legislation designed to prepare for, prevent and respond to weather emergencies and power outages. On November 30, 2021, the RRC adopted rules to designate certain natural gas facilities as critical infrastructure. While the Commission did not adopt rules related to other sections of the legislation requiring such designees to implement weatherization measures, it is expected that the Commission will initiate a rulemaking at a later date for such purposes.

Under the new rules, “critical gas suppliers” include, but are not limited to, gas wells, oil leases that produce gas, natural gas pipeline facilities, underground natural gas storage facilities and saltwater disposal facilities. “Critical customers,” which are a subset of critical gas suppliers, are facilities that require electricity to operate. The rules allow for certain facilities to apply for an exception to critical designation, but exclude certain types of highly critical facilities from eligibility for such exception.

If we are designated as a “critical gas supplier” or “critical customer,” we would become subject to additional regulation and compliance costs, including potential future operating and capital costs required to weatherize our assets.

Enhanced scrutiny on ESG matters could have an adverse effect on the Company’s operations.

Enhanced scrutiny on ESG matters related to, among other things, concerns raised by advocacy groups about climate change, hydraulic fracturing, waste disposal, oil spills, and explosions of natural gas transmission pipelines may lead to increased regulatory scrutiny, which may, in turn, lead to new state and federal safety and environmental laws, regulations, guidelines, and enforcement interpretations. These actions may cause operational delays or restrictions, increased operating costs, additional regulatory burdens, increased risk of litigation, and adverse impacts on the Company’s access to capital. Moreover, governmental authorities exercise considerable discretion in the timing and scope of permit issuance, and the public may engage in the permitting process, including through intervention in the courts. Negative public perception could cause the permits the Company requires to conduct its operations to be withheld, delayed, or burdened by requirements that restrict the Company’s ability to profitably conduct its business.

We may be unable to quickly adapt to changes in market/investor priorities.

Historically, one of the key drivers in the unconventional resource industry has been growth in production and reserves. With historical volatility in oil and natural gas prices and the likelihood that rising interest rates will increase the cost of borrowing, capital efficiency and free cash flow from earnings have become the key drivers for energy companies, particularly shale producers. Such shifts in focus sometimes require changes in planning and resource management, which may not occur instantaneously. Any delay in responding to such changes in market sentiment or perception may result in the investment community having a negative sentiment regarding our business plan, potential profitability and our ability to operate in a manner deemed "efficient," which may have a negative impact on the price of our common stock.

The adoption of climate change legislation or regulations restricting GHG emissions could result in increased operating costs and reduced demand for the oil, NGL and natural gas we produce, while potential physical effects of climate change could disrupt our operations and cause us to incur significant costs in preparing for or responding to those effects.

Restrictions on GHG emissions that may be imposed could adversely affect the oil and gas industry. The adoption of legislation or regulatory programs to reduce GHG emissions could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, acquire emissions allowances or comply with new regulatory requirements. Any GHG emissions legislation or regulatory programs applicable to power plants or refineries could also increase the cost of consuming, and thereby reduce demand for, the oil, natural gas and NGL we produce. Consequently, legislation and regulatory programs to reduce GHG emissions could have an adverse effect on our business, financial condition and results of operations.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Not applicable.

Item 3. Defaults Upon Senior Securities

Not applicable.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

Not applicable.

Item 6. Exhibits

Exhibit Number	Description
2.1	Agreement and Plan of Merger, by and among Tengasco, Inc., Antman Sub, LLC, and Riley Exploration - Permian, LLC, dated as of October 21, 2020 (incorporated by reference from Exhibit 2.1 to the Registrant's Current Report on Form 8-K filed with the Securities and Exchange Commission on October 22, 2020).
2.2	Amendment No. 1 to Agreement and Plan of Merger, by and among Tengasco, Inc., Antman Sub, LLC, and Riley Exploration - Permian, LLC, dated as of January 20, 2021 (incorporated by reference from Exhibit 2.1 to the Registrant's Current Report on Form 8-K, as filed with the Securities and Exchange Commission on January 22, 2021).
3.1	First Amended and Restated Certificate of Incorporation of Riley Exploration Permian, Inc. (incorporated by reference to Exhibit 4.1 to the Registrant's Registration Statement on Form S-8 filed with the Securities and Exchange Commission on March 1, 2021, Registration No. 333-253750).
3.2	Second Amended and Restated Bylaws of Riley Exploration Permian, Inc. (incorporated by reference to Exhibit 4.2 to the Registrant's Registration Statement on Form S-8 filed with the Securities and Exchange Commission on March 1, 2021, Registration No. 333-253750).
3.3	Third Amended and Restated Bylaws of Riley Exploration Permian, Inc. (incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the Securities and Exchange Commission on September 23, 2022).
10.1	Credit Agreement dated as of September 28, 2017, by and among Riley Exploration – Permian, LLC, as borrower, Truist Bank, as administrative agent, and the lenders party thereto (incorporated by reference from Exhibit 10.1 to the Registrant's Registration Statement on Form S-4/A, as filed with the Securities and Exchange Commission on December 31, 2020, Registration No. 333-250019).
10.2	First Amendment to Credit Agreement dated as of February 27, 2018, by and among Riley Exploration – Permian, LLC, as borrower, Truist Bank, as administrative agent, and the lenders party thereto (incorporated by reference from Exhibit 10.2 to the Registrant's Registration Statement on Form S-4/A, as filed with the Securities and Exchange Commission on December 31, 2020, Registration No. 333-250019).
10.3	Second Amendment to Credit Agreement dated as of November 9, 2018, by and among Riley Exploration – Permian, LLC, as borrower, Truist Bank, as administrative agent, and the lenders party thereto (incorporated by reference from Exhibit 10.3 to the Registrant's Registration Statement on Form S-4/A, as filed with the Securities and Exchange Commission on December 31, 2020, Registration No. 333-250019).
10.4	Third Amendment to Credit Agreement dated as of April 3, 2019, by and among Riley Exploration – Permian, LLC, as borrower, Truist Bank, as administrative agent, and the lenders party thereto (incorporated by reference from Exhibit 10.4 to the Registrant's Registration Statement on Form S-4/A, as filed with the Securities and Exchange Commission on December 31, 2020, Registration No. 333-250019).
10.5	Fourth Amendment to Credit Agreement dated as of October 15, 2019, by and among Riley Exploration – Permian, LLC, as borrower, Truist Bank, as administrative agent, and the lenders party thereto (incorporated by reference from Exhibit 10.5 to the Registrant's Registration Statement on Form S-4/A, as filed with the Securities and Exchange Commission on December 31, 2020, Registration No. 333-250019).
10.6	Fifth Amendment to Credit Agreement dated as of May 7, 2020, by and among Riley Exploration – Permian, LLC, as borrower, Truist Bank, as administrative agent, and the lenders party thereto (incorporated by reference from Exhibit 10.6 to the Registrant's Registration Statement on Form S-4/A, as filed with the Securities and Exchange Commission on December 31, 2020, Registration No. 333-250019).
10.7	Sixth Amendment to Credit Agreement dated as of August 31, 2020, by and among Riley Exploration – Permian, LLC, as borrower, Truist Bank, as administrative agent, and the lenders party thereto (incorporated by reference from Exhibit 10.7 to the Registrant's Registration Statement on Form S-4/A, as filed with the Securities and Exchange Commission on December 31, 2020, Registration No. 333-250019).
10.8	Seventh Amendment and Consent to Credit Agreement dated as of October 21, 2020, by and among Riley Exploration – Permian, LLC, as borrower, Truist Bank, as administrative agent, and the lenders party thereto (incorporated by reference from Exhibit 10.8 to the Registrant's Registration Statement on Form S-4/A, as filed with the Securities and Exchange Commission on December 31, 2020, Registration No. 333-250019).

10.9	Eighth Amendment to Credit Agreement dated as of March 5, 2021, by and among Riley Exploration Permian, Inc., Riley Exploration - Permian, LLC, as borrower, Truist Bank, as administrative agent, and the lenders party thereto (incorporated by reference from Exhibit 10.9 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2021, as filed with the Securities and Exchange Commission on May 17, 2021).
10.10	Ninth Amendment to Credit Agreement dated as of May 5, 2021, by and among Riley Exploration Permian, Inc., Riley Exploration - Permian, LLC, as borrower, Truist Bank, as administrative agent, and the lenders party thereto (incorporated by reference from Exhibit 10.10 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2021, as filed with the Securities and Exchange Commission on May 17, 2021).
10.11	Tenth Amendment to the Credit Agreement dated as of October 12, 2021, by and among Riley Exploration Permian, Inc., Riley Exploration - Permian, LLC, as borrower, Truist Bank, as administrative agent, and the lenders party thereto (incorporated by reference from Exhibit 10.1 to the Registrant's Current Report on Form 8-K, as filed with the Securities and Exchange Commission on October 14, 2021).
10.12	Form of Indemnity Agreement (incorporated by reference from Exhibit 10.14 to the Registrant's Registration Statement on Form S-4/A, as filed with the Securities and Exchange Commission on January 21, 2021, Registration No. 333-250019).
10.13	Form of Independent Director Agreement (incorporated by reference from Exhibit 10.13 to the Registrant's Registration Statement on Form S-4/A, as filed with the Securities and Exchange Commission on January 21, 2021, Registration No. 333-250019).
10.14†	Riley Exploration Permian, Inc. 2021 Long Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the Commission on February 25, 2021).
10.15†	Form of Common Stock Award Agreement (incorporated by reference from Exhibit 10.10 to the Registrant's Current Report on Form 8-K, as filed with the Securities and Exchange Commission on March 15, 2021).
10.16†	Form of Restricted Stock Agreement (Time Vesting) (incorporated by reference to Exhibit 4.4 to the Registrant's Registration Statement on Form S-8, as filed with the Securities and Exchange Commission on March 1, 2021, Registration No. 333- 253750).
10.17†	Form of Substitute Restricted Stock Agreement (Time Vesting) (incorporated by reference from Exhibit 4.5 to the Registrant's Registration Statement on Form S-8 filed with the Commission on March 1, 2021, Registration No. 333-253750).
10.18†	Form of Restricted Stock Agreement (Non-Employee Director) (incorporated by reference from Exhibit 4.6 to the Registrant's Registration Statement on Form S-8 filed with the Commission on March 1, 2021, Registration No. 333-253750).
10.19†	Employment Agreement dated effective as of March 15, 2021 by and between Riley Exploration Permian, Inc. and Corey Riley (incorporated by reference from Exhibit 10.1 to the Registrant's Current Report on Form 8-K, as filed with the Securities and Exchange Commission on March 15, 2021).
10.20†	Employment Agreement dated effective as of March 15, 2021 by and between Riley Exploration Permian, Inc. and Philip Riley (incorporated by reference from Exhibit 10.2 to the Registrant's Current Report on Form 8-K, as filed with the Securities and Exchange Commission on March 15, 2021).
10.21†	Employment Agreement dated April 1, 2019 by and between Riley Exploration – Permian, LLC and Bobby D. Riley and assigned by Riley Exploration – Permian, LLC to Riley Permian Operating Company, LLC on June 8, 2019 (incorporated by reference from Exhibit 10.9 to the Registrant's Registration Statement on Form S-4/A, as filed with the Securities and Exchange Commission on December 31, 2020, Registration No. 333-250019).
10.22†	Amendment No. 1 to Employment Agreement dated October 1, 2020 by and between Riley Permian Operating Company, LLC and Bobby D. Riley (incorporated by reference from Exhibit 10.10 to the Registrant's Registration Statement on Form S-4/A, as filed with the Securities and Exchange Commission on December 31, 2020, Registration No. 333-250019).
10.23†	Amendment No. 2 to Employment Agreement dated March 15, 2021 by and between Riley Permian Operating Company, LLC and Bobby D. Riley (incorporated by reference from Exhibit 10.7 to the Registrant's Current Report on Form 8-K, as filed with the Securities and Exchange Commission on March 15, 2021).

10.24†	Employment Agreement dated April 1, 2019 by and between Riley Exploration – Permian, LLC and Kevin Riley and assigned by Riley Exploration – Permian, LLC to Riley Permian Operating Company, LLC on June 8, 2019 (incorporated by reference from Exhibit 10.11 to the Registrant's Registration Statement on Form S-4/A, as filed with the Securities and Exchange Commission on December 31, 2020, Registration No. 333-250019)
10.25†	Amendment No. 1 to Employment Agreement dated March 15, 2021 by and between Riley Permian Operating Company, LLC and Kevin Riley (incorporated by reference from Exhibit 10.8 to the Registrant's Current Report on Form 8-K, as filed with the Securities and Exchange Commission on March 15, 2021).
10.26	Second Amended and Restated Registration Rights Agreement dated October 7, 2020 by and among Riley Exploration – Permian, LLC, Riley Exploration Group, Inc., Yorktown Energy Partners XI, L.P., Boomer Petroleum, LLC, Bluescape Riley Exploration Holdings LLC, Bluescape Riley Acquisition Company LLC, Bobby D. Riley, Kevin Riley and Corey Riley (incorporated by reference to Exhibit 4.1 to the Registrant's Registration Statement on Form S-4/A, as filed with the Securities and Exchange Commission on December 31, 2020, Registration No. 333-250019).
10.27†	Employment Agreement dated effective as of January 25, 2022 by and between Riley Exploration Permian, Inc. and Amber Bonney (incorporated by reference from Exhibit 10.2 to the Registrant's Current Report on Form 8-K, as filed with the Securities and Exchange Commission on January 27, 2022).
10.28	Eleventh Amendment to the Credit Agreement dated as of April 29, 2022, by and among Riley Exploration Permian, Inc., Riley Exploration - Permian, LLC, as borrower, Truist Bank, as administrative agent, and the lenders party thereto (incorporated by reference from Exhibit 10.1 to the Registrant's Current Report on Form 8-K, as filed with the Securities and Exchange Commission on May 2, 2022).
23.1*	Consent of BDO USA, LLP
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certification of Chief Executive Officer pursuant to 18 U.S.C., Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2*	Certification of Chief Financial Officer pursuant to 18 U.S.C., Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1*	Report of Netherland, Sewell & Associates, Inc.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Definition Linkbase Document
101.LAB*	XBRL Taxonomy Label Linkbase Document
101.PRE*	XBRL Taxonomy Presentation Linkbase Document

* Filed herewith.

† Compensatory plan or arrangement.

SIGNATURES

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

RILEY EXPLORATION PERMIAN, INC.

Date: September 23, 2022

By: /s/ Bobby D. Riley
Bobby D. Riley
Chief Executive Officer

By: /s/ Philip Riley
Philip Riley
Chief Financial Officer

Consent of Independent Registered Public Accounting Firm

Riley Exploration Permian, Inc.
Oklahoma City, Oklahoma

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-255104) and Form S-8 (No. 333-253750) of Riley Exploration Permian, Inc. of our report dated September 23, 2022, relating to the consolidated financial statements which appears in this Form 10-QT.

/s/ BDO USA, LLP
Houston, Texas

September 23, 2022

NETHERLAND, SEWELL & ASSOCIATES, INC.

Exhibit 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the inclusion in this Transition Report on Form 10-QT of Riley Exploration Permian, Inc. for the three months ended December 31, 2021, of our report dated June 22, 2022, with respect to estimates of reserves and future net revenue of Riley Exploration Permian, Inc., as of December 31, 2021, and to all references to our firm included in this Transition Report.

NETHERLAND, SEWELL & ASSOCIATES, INC.

/s/ Eric J. Stevens
By:
Eric J. Stevens, P.E.
President and Chief Operating Officer

Dallas, Texas
September 23, 2022

CERTIFICATION

I, Bobby D. Riley, certify that:

1. I have reviewed this Transition Report on Form 10-QT of Riley Exploration Permian, Inc. for the quarter ended December 31, 2021.

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 officers 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 officers 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.

Dated: September 23, 2022

By: /s/ Bobby D. Riley

Bobby D. Riley
Chief Executive Officer

CERTIFICATION

I, Philip Riley, certify that:

1. I have reviewed this Transition Report on Form 10-QT of Riley Exploration Permian, Inc. for the quarter ended December 31, 2021.

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 officers 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 officers 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.

Dated: September 23, 2022

By: /s/ Philip Riley

Philip Riley

Chief Financial Officer

Exhibit 32.1

CERTIFICATION

Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 I hereby certify that:

I have reviewed the Transition Report on Form 10-QT of Riley Exploration Permian, Inc. (the "Company") for the quarter ended December 31, 2021 (the "Report").

To the best of my knowledge the Report (i) fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m (a) or 78o (d)); and, (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: September 23, 2022

By: /s/ Bobby D. Riley

Bobby D. Riley

Chief Executive Officer

CERTIFICATION

Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 I hereby certify that:

I have reviewed the Transition Report on Form 10-QT of Riley Exploration Permian, Inc. (the “Company”) for the quarter ended December 31, 2021 (the “Report”).

To the best of my knowledge the Report (i) fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m (a) or 78o (d)); and, (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: September 23, 2022

By: /s/ Philip Riley

Philip Riley
Chief Financial Officer

Exhibit 99.1

June 22, 2022

Mr. Dan Doherty
Riley Exploration Permian, Inc.
29 East Reno Avenue, Suite 500
Oklahoma City, Oklahoma 73104

Dear Mr. Doherty:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2021, to the Riley Exploration Permian, Inc. (Riley Permian) interest in certain oil and gas properties located in New Mexico and Texas. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by Riley Permian. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Riley Permian's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the Riley Permian interest in these properties, as of December 31, 2021, to be:

	Net Reserves			Future Net Revenue (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	27,096.1	7,949.3	47,974.1	1,401,170.4	616,795.8
Proved Developed Shut-In(1)	0.0	0.0	0.0	-666.6	-565.0
Proved Undeveloped	19,925.6	5,522.4	29,512.3	821,395.8	262,912.3
Total Proved	47,021.7	13,471.7	77,486.5	2,221,899.6	879,143.1

Totals may not add because of rounding.

(1) Future net revenue is after deducting estimated abandonment costs.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. Our study indicates that as of December 31, 2021, there are no proved developed non-producing reserves for these properties. As requested, probable and possible reserves that exist for these properties have not been included. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

Gross revenue is Riley Permian's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Riley Permian's share of production taxes, ad valorem taxes, capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2021. For oil and NGL volumes, the average West Texas Intermediate spot price of $66.55 per barrel is adjusted by basin for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $3.598 per MMBTU is adjusted by basin for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $64.60 per barrel of oil, $13.75 per barrel of NGL, and $1.646 per MCF of gas.

Operating costs used in this report are based on operating expense records of Riley Permian. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs have been divided into per-well costs and per-unit-of-production costs. Headquarters general and administrative overhead expenses of Riley Permian are included to the extent that they are covered under joint operating agreements for the operated properties. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by Riley Permian and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. For all vertical proved developed producing wells and all proved developed shut-in wells, abandonment costs used in this report are Riley Permian's estimates of the costs to abandon the wells and production facilities, net of any salvage value. For the remainder of the properties, Riley Permian has estimated the costs to abandon the wells and production facilities to be equivalent to the salvage value; therefore, the net effect of the inclusion of abandonment costs and salvage value on the future net revenue for these properties is zero. Capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Riley Permian interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Riley Permian receiving its net revenue interest share of estimated future gross production. Additionally, we have made no specific investigation of any firm transportation contracts that may be in place for these properties; our estimates of future revenue include the effects of such contracts only to the extent that the associated fees are accounted for in the historical field- and lease-level accounting statements.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Riley Permian, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. A substantial portion of these reserves are for undeveloped locations; such reserves are based on analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

Exhibit 99.1

The data used in our estimates were obtained from Riley Permian, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical person primarily responsible for preparing the estimates presented herein meets the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Michael B. Begland, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 1993 and has over 8 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.

Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees III

C.H. (Scott) Rees III, P.E.

Executive Chairman

By: /s/ Michael B. Begland

Michael B. Begland, P.E. 104898

Vice President

Date Signed: June 22, 2022

NETHERLAND, SEWELL & ASSOCIATES, INC.

Exhibit 99.1

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2018 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir*. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
(ii) Same environment of deposition;
(iii) Similar geological structure; and
(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen*. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate*. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate*. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves*. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2018 Petroleum Resources Management System:

Developed Producing Reserves – Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate. Improved recovery Reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

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

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

(8) *Development project*. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a

producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well*. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible*. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)*. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs*. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field*. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities*.

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and
(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.
(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.
(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.
(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate*. The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs*.

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)
b. Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.
b. Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.
c. Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.
d. Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.
e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.
f. Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.

(27) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);
The company's historical record at completing development of comparable long-term projects;
The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;
The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and
The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.