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

FORM 10-Q

(Mark One)

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE QUARTERLY PERIOD ENDED September 30, 2021**

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

COMMISSION FILE NUMBER: 001-16071

ABRAXAS PETROLEUM CORPORATION

(Exact name of registrant as specified in its charter)

Nevada	**74-2584033**
(State of Incorporation)	(I.R.S. Employer Identification No.)

18803 Meisner Drive, San Antonio, TX 78258
(Address of principal executive offices) (Zip Code)

210-490-4788
(Registrant's telephone number, including area code)

Not Applicable
(Former name, former address and former fiscal year, if changed since last report)

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

Title of each class	Trading Symbol	Name of each exchange on which registered:
Common Stock, par value $.01 per share	AXAS	OTCQX

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 the filing requirements for the past 90 days. Yes ☒ No ☐

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act. (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 Sec 13(a) of the Exchange Act. ☐

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

The number of shares of the issuer's common stock outstanding as of November 12, 2021 was 8,421,910.

The terms "Abraxas," "Abraxas Petroleum," "we," "us," "our" or the "Company" refer to Abraxas Petroleum Corporation and all of its subsidiaries, including Raven Drilling, LLC.

All share and per share data has been retroactively adjusted to reflect the 1-for-20 reverse stock split effective October 19, 2020, as described in Note 2 to our consolidated financial statements.

Forward-Looking Information

We make forward-looking statements throughout this report. Whenever you read a statement that is not simply a statement of historical fact (such as statements including words like "believe," "expect," "anticipate," "intend," "will," "plan," "seek," "may," "estimate," "could," "potentially" or similar expressions), you must remember that these are forward-looking statements, and that our expectations may not be correct, even though we believe they are reasonable. The forward-looking information contained in this report is generally located in the material set forth under the headings "Management's Discussion and Analysis of Financial Condition and Results of Operations" but may be found in other locations as well. These forward-looking statements generally relate to our plans and objectives for future operations and are based upon our management's reasonable estimates of future results or trends. The factors that may affect our expectations regarding our operations include, among others, the following:

- the prices we receive for our production and the effectiveness of our hedging activities;
- the availability of capital including under our credit facility;
- our success in development, exploitation and exploration activities;
- declines in our production of oil and gas;
- our indebtedness and the significant amount of cash required to service our indebtedness;
- the proximity, capacity, cost and availability of pipelines and other transportation facilities;
- limits on our growth and our ability to finance our operations, fund our capital needs and respond to changing conditions imposed by our bank credit facility and restrictive debt covenants;
- our ability to make planned capital expenditures;
- ceiling test write-downs resulting, and that could result in the future, from lower oil and natural gas prices;
- global or national health concerns, including the outbreak of pandemic or contagious disease, such as the coronavirus (COVID-19);
- political and economic conditions in oil producing countries, especially those in the Middle East;
- price and availability of alternative fuels;
- our ability to procure services and equipment for our drilling and completion activities;
- our acquisition and divestiture activities;
- weather conditions and events; and
- other factors discussed elsewhere in this report.

Initial production, or IP rates, for both our wells and for those wells that are located near our properties, are limited data points in each well's productive history. These rates are sometimes actual rates and sometimes extrapolated or normalized rates. As such, the rates for a particular well may change as additional data become available. Peak production rates are not necessarily indicative or predictive of future production rates, expected ultimate recovery (EUR), or economic rates of return from such wells and should not be relied upon for such purpose. Equally, the way we calculate and report peak IP rates and the methodologies employed by others may not be consistent, and thus the values reported may not be directly and meaningfully comparable. Lateral lengths described are indicative only. Actual completed lateral lengths depend on various considerations such as lease-line offsets. Abraxas standard length laterals, sometimes referred to as 5,000 foot laterals, are laterals with completed length generally between 4,000 feet and 5,500 feet. Mid-length laterals, sometimes referred to as 7,500 foot laterals, are laterals with completed length generally between 6,500 feet and 8,000 feet. Long laterals, sometimes referred to as 10,000 foot laterals, are laterals with completed length generally longer than 8,000 feet.

GLOSSARY OF TERMS

Unless otherwise indicated in this report, gas volumes are stated at the legal pressure base of the State or area in which the reserves are located at 60 degrees Fahrenheit. Oil and gas equivalents are determined using the ratio of six Mcf of gas to one barrel of oil, condensate or natural gas liquids.

The following definitions apply to the technical terms used in this report.

Terms used to describe quantities of oil and gas:

"***Bbl***" – barrel or barrels.

"***Bcf***" – billion cubic feet of gas.

"***Bcfe***" – billion cubic feet of gas equivalent.

"***Boe***" – barrels of oil equivalent.

"***Boed or Boepd***" – barrels of oil equivalent per day.

"***MBbl***" – thousand barrels.

"MBoe" **–** thousand barrels of oil equivalent.

"***Mcf***" – thousand cubic feet of gas.

"***Mcfe***" – thousand cubic feet of gas equivalent.

"***MMBbl***" – million barrels.

"MMBoe" – million barrels of oil equivalent.

"***MMBtu***" – million British Thermal Units of gas.

"***MMcf***" – million cubic feet of gas.

"***MMcfe***" – million cubic feet of gas equivalent.

"NGL" **–** natural gas liquids measured in barrels.

Terms used to describe our interests in wells and acreage:

"***Developed acreage***" means acreage which consists of leased acres spaced or assignable to productive wells.

"***Development well***" is a well drilled within the proved area of an oil or gas reservoir to the depth or stratigraphic horizon (rock layer or formation) noted to be productive for the purpose of extracting reserves.

"***Dry hole***" is an exploratory or development well found to be incapable of producing either oil or gas in sufficient quantities to justify completion.

"***Exploratory well***" is a well drilled to find and produce oil and or gas in an unproved area, to find a new reservoir in a field previously found to be producing in another reservoir, or to extend a known reservoir.

"***Gross acres***" are the number of acres in which we own a working interest.

"***Gross well***" is a well in which we own a working interest.

"***Net acres***" are the sum of fractional ownership working interests in gross acres (e.g., a 50% working interest in a lease covering 320 gross acres is equivalent to 160 net acres).

"***Net well***" is the sum of fractional ownership working interests in gross wells.

"***Productive well***" is an exploratory or a development well that is not a dry hole.

"***Undeveloped acreage***" means those leased acres on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil and gas, regardless of whether such acreage contains proved reserves.

Terms used to assign a present value to or to classify our reserves:

"***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.

"Proved developed non-producing reserves*" are those quantities of oil and gas reserves that are developed behind pipe in an existing well bore, from a shut-in well bore or that can be recovered through improved recovery only after the necessary equipment has been installed, or when the costs to do so are relatively minor. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, (2) wells that 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 recompletion prior to the start of production.

"Proved developed reserves*" Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

"***Proved reserves****" Reserves that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

"Proved undeveloped reserves" *or* ***"PUDs*"*** Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells, in each case where a relatively major expenditure is required.

"***PV-10***" means estimated future net revenue, discounted at a rate of 10% per annum, before income taxes and with no price or cost escalation or de-escalation, calculated in accordance with guidelines promulgated by the Securities and Exchange Commission ("SEC"). PV-10 is considered a non-GAAP financial measure under SEC regulations because it does not include the effects of future income taxes, as is required in computing the standardized measure of discounted future net cash flows. We believe that PV-10 is an important measure that can be used to evaluate the relative significance of our oil and gas properties and that PV-10 is widely used by securities analysts and investors when evaluating oil and gas companies. Because many factors that are unique to each individual company impact the amount of future income taxes to be paid, the use of a pre-tax measure provides greater comparability of assets when evaluating companies. We believe that most other companies in the oil and gas industry calculate PV-10 on the same basis. PV-10 is computed on the same basis as the standardized measure of discounted future net cash flows but without deducting income taxes.

"***Standardized Measure***" means estimated future net revenue, discounted at a rate of 10% per annum, after income taxes and with no price or cost escalation or de-escalation, calculated in accordance with Accounting Standards Codification ("ASC") 932, "Disclosures About Oil and Gas Producing Activities."

"***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.

* This definition is an abbreviated version of the complete definition set forth in Rule 4-10(a) of Regulation S-X.

ABRAXAS PETROLEUM CORPORATION
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Part I
FINANCIAL STATEMENTS

Item 1. Financial Statements

ABRAXAS PETROLEUM CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(in thousands)

	September 30, 2021 (Unaudited)	December 31, 2020
Assets		
Current assets:		
Cash and cash equivalents	$ 9,051	$ 2,775
Accounts receivable:		
Joint owners, net	1,250	1,255
Oil and gas production sales	13,272	8,794
Other	293	-
Total accounts receivable	14,815	10,049
Derivative asset - short-term	-	9,639
Other current assets	993	1,588
Total current assets	24,859	24,051
Property and equipment:		
Proved oil and gas properties, full cost method	1,165,232	1,167,333
Other property and equipment	39,257	39,456
Total	1,204,489	1,206,789
Less accumulated depreciation, depletion, amortization and impairment	(1,095,459)	(1,083,843)
Total property and equipment, net	109,030	122,946
Operating lease right-of-use assets	184	228
Derivative asset - long-term	-	10,281
Other assets	255	255
Total assets	$ 134,328	$ 157,761

All share and per share data has been retroactively adjusted to reflect the 1-for-20 reverse stock split effective October 19, 2020, as described in Note 2 to our condensed consolidated financial statements.

See accompanying notes to condensed consolidated financial statements (unaudited).

ABRAXAS PETROLEUM CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS (CONTINUED)
(in thousands, except share and per share data)

	September 30, 2021 (Unaudited)	December 31, 2020
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable	$ 2,061	$ 6,074
Joint interest oil and gas production payable	12,835	8,795
Accrued interest	511	86
Accrued expenses	892	230
Right of use liability	41	53
Derivative liabilities - short-term	2,017	480
Termination of derivative contracts	9,178	—
Current maturities of long-term debt	209,434	202,751
Other current liabilities	-	850
Total current liabilities	236,969	219,319
Long-term debt – less current maturities	2,284	2,515
Operating lease right-of-use liabilities	118	150
Paycheck protection program loan	1,336	1,384
Future site restoration	4,748	7,360
Total liabilities	245,455	230,728
Commitments and contingencies (Note 11)		
Stockholders' Equity:		
Preferred stock, par value $0.01 per share – authorized 1,000,000 shares; -0- shares issued and outstanding	—	—
Common stock, par value $0.01 per share, authorized 20,000,000 shares; 8,421,910 issued and outstanding at September 30, 2021 and December 31, 2020	84	84
Additional paid-in capital	430,256	429,476
Accumulated deficit	(541,467)	(502,527)
Total stockholders' deficit	(111,127)	(72,967)
Total liabilities and stockholders' deficit	$ 134,328	$ 157,761

See accompanying notes to condensed consolidated financial statements (unaudited).

ABRAXAS PETROLEUM CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)
(in thousands except per share data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Revenues:				
Oil and gas production revenues				
Oil	$ 15,506	$ 12,466	$ 45,199	$ 29,971
Gas	2,415	75	5,344	183
Natural gas liquids	2,933	52	5,416	152
Other	11	2	19	8
Total revenue	20,865	12,595	55,978	30,314
Operating costs and expenses:				
Lease operating	4,612	3,935	13,059	12,280
Production and ad valorem taxes	1,551	1,520	4,624	3,613
Rig expense	119	130	363	669
Depreciation, depletion, amortization and accretion	3,812	7,019	11,951	19,053
Proved property impairment	—	54,552	—	136,109
General and administrative (including stock-based compensation of $273, $348, $780, and $947, respectively)	1,942	2,100	6,253	6,506
Total operating cost and expenses	12,036	69,256	36,250	178,230
Operating income (loss)	8,829	(56,661)	19,728	(147,916)
Other (income) expense:				
Interest income	(4)	(6)	(13)	(24)
Interest expense	8,057	5,676	21,742	15,569
Gain on sale of non-oil and gas assets	—	—	(29)	—
Amortization of deferred financing fees	1,201	546	3,603	1,067
Financing expense	568	—	1,852	—
Debt forgiveness	—	—	(1,384)	—
Loss on debt extinguishment	—	4,108	—	4,108
Loss (gain) on derivative contracts	252	6,630	32,897	(53,208)
Total other expense (income)	10,074	16,954	58,668	(32,488)
(Loss) before income tax	(1,245)	(73,615)	(38,940)	(115,428)
Income tax (expense) benefit	—	—	—	—
Net (loss)	$ (1,245)	$ (73,615)	$ (38,940)	$ (115,428)
Net (loss) per common share - basic	$ (0.15)	$ (8.80)	$ (4.63)	$ (13.80)
Net (loss) per common share - diluted	$ (0.15)	$ (8.80)	$ (4.63)	$ (13.80)
Weighted average shares outstanding:				
Basic	8,406	8,362	8,406	8,366
Diluted	8,406	8,362	8,406	8,366

See accompanying notes to condensed consolidated financial statements (unaudited).

ABRAXAS PETROLEUM CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY
(Unaudited)
(in thousands, except share data)

	Common Stock		Additional Paid in Capital	Accumulated Deficit	Total
	Shares	Amount			
Balance at December 31, 2020	8,421,910	$ 84	$ 429,476	$ (502,527)	$ (72,967)
Net loss	-	-	-	(38,940)	(38,940)
Stock-based compensation	-	-	780	-	780
Balance at September 30, 2021	8,421,910	$ 84	$ 430,256	$ (541,467)	$ (111,127)

	Common Stock		Additional Paid in Capital	Accumulated Deficit	Total
	Shares	Amount			
Balance at December 31, 2019	8,418,053	$ 84	$ 421,740	$ (318,005)	$ 103,819
Net loss	-	-	-	(115,428)	(115,428)
Stock-based compensation	-	-	947	-	947
Issuance of warrant	-	-	6,424	-	6,424
Restricted stock issued, net of forfeitures	(14,588)	-	-	-	-
Balance at September 30, 2020	8,403,465	$ 84	$ 429,111	$ (433,433)	$ (4,238)

	Common Stock		Additional Paid in Capital	Accumulated Deficit	Total
	Shares	Amount			
Balance at June 30, 2021	8,421,910	$ 84	$ 429,983	$ (540,222)	$ (110,155)
Net loss	-	-	-	(1,245)	(1,245)
Stock-based compensation	-	-	273	-	273
Balance at September 30, 2021	8,421,910	$ 84	$ 430,256	$ (541,467)	$ (111,127)

	Common Stock		Additional Paid in Capital	Accumulated Deficit	Total
	Shares	Amount			
Balance at June 30, 2020	8,403,465	$ 84	$ 422,339	$ (359,818)	$ 62,605
Net loss	-	-	-	(73,615)	(73,615)
Issuance of warrant	-	-	6,424	-	6,424
Stock-based compensation	-	-	348	-	348
Balance at September 30, 2020	8,403,465	$ 84	$ 429,111	$ (433,433)	$ (4,238)

See accompanying notes to condensed consolidated financial statements (unaudited).

ABRAXAS PETROLEUM CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)
(in thousands)

	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020
Operating Activities		
Net loss	$ (38,940)	$ (115,428)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Net loss (gain) on derivative contracts	32,897	(53,208)
Net cash settlements paid on derivative contracts	(1,497)	12,400
Gain on sale of non-oil and gas properties	(29)	—
Depreciation, depletion, amortization and accretion of future site restoration	11,951	19,053
Proved property impairment	—	136,109
Amortization of deferred financing fees and issuance discount	5,734	2,226
Stock-based compensation	780	947
Settlements of asset retirement obligations	336	310
Debt forgiveness PPP loan	(1,384)	—
Loss on debt extinguishment	—	4,108
Non-cash interest expense	14,406	8,323
Non-cash hedge contract termination	9,943	—
Changes in operating assets and liabilities:		
Accounts receivable	(4,766)	12,158
Other assets	(10,186)	1,459
Accounts payable and accrued expenses	631	(17,723)
Net cash provided by operating activities	19,876	10,734
Investing Activities		
Capital expenditures, including purchases and development of properties	(856)	(13,187)
Proceeds from the sale of oil and gas properties	117	—
Proceeds from the sale of non-oil and gas properties	256	—
Net cash used in investing activities	(483)	(13,187)
Financing Activities		
Proceeds from long-term borrowings	—	8,000
Proceeds from PPP loan	1,336	—
Payments on long-term borrowings	(14,296)	(3,987)
Deferred financing fees	(157)	(977)
Net cash (used in) provided by financing activities	(13,117)	3,036
Increase in cash and cash equivalents	6,276	583
Cash and cash equivalents at beginning of period	2,775	—
Cash and cash equivalents at end of period	$ 9,051	$ 583
Supplemental disclosures of cash flow information:		
Interest paid	$ 4,667	$ 6,085
Non-cash investing and financing activities:		
Non-cash interest paid in kind	$ 14,406	$ 8,323
Change in capital expenditures included in accounts payable	$ 28	$ (6,619)
Change in future site restoration on properties sold	$ 2,704	$ -
Forgiveness of PPP loan	$ 1,384	$ -

See accompanying notes to condensed consolidated financial statements (unaudited).

ABRAXAS PETROLEUM CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
(tabular amounts in thousands, except per share data)

1. Basis of Presentation

The accounting policies we follow as of January 1, 2021 are set forth in the notes to our audited consolidated financial statements in the Annual Report on Form 10-K for the year ended December 31, 2020 filed with the SEC on May 6, 2021. The accompanying interim condensed consolidated financial statements have not been audited by our independent registered public accountants. In the opinion of management, these statements reflect all adjustments necessary for a fair presentation of the financial position and results of operations. Any and all adjustments are of a normal and recurring nature. Although management believes the unaudited interim related disclosures in these condensed consolidated financial statements are adequate to make the information presented not misleading, certain information and footnote disclosures normally included in annual audited consolidated financial statements prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") have been condensed or omitted pursuant to the rules and regulations of the SEC. The results of operations for the three and nine month periods ended September 30, 2021 and the statement of cash flows for the nine months ended September 30, 2021, are not necessarily indicative of the results to be expected for the full year. The condensed consolidated financial statements included herein should be read in conjunction with the consolidated audited financial statements and the notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2020.

COVID-19

In the first quarter of 2020, a new strain of coronavirus ("COVID-19") emerged, creating a global health emergency that has been classified by the World Health Organization as a pandemic. As a result of the COVID-19 pandemic, consumer demand for both oil and gas decreased as a direct result of travel restrictions placed by governments in an effort to curtail the spread of COVID-19 and its variant strains. In addition, in March 2020, members of Organization of Petroleum Exporting Countries ("OPEC") failed to agree on production levels, which caused an increased supply of oil and gas and led to a substantial decrease in oil prices and an increasingly volatile market. OPEC agreed to cut global petroleum output but did not go far enough to offset the impact of COVID-19 on demand. As a result of this decrease in demand and increase in supply, the price of oil and gas decreased, which affected our liquidity. Since that time, demand and the price of oil and gas have increased, but uncertainty related to the pandemic caused by COVID-19 and its variant strains persists.

In early March 2020, global oil and natural gas prices declined sharply, rising in recent months, but may decline again. The full impact of COVID-19 and its variant strains continues to evolve as of the date of this report. As such, it is uncertain as to the full magnitude they will have on the Company. Management is actively monitoring the global situation and the impact on the Company's future operations, financial position and liquidity in fiscal year 2021. In response to the price volatility, the Company took action to reduce general and administrative costs, as well as shut in production in mid- March 2020. Subsequently, however the Company started restoring production in mid- June 2020, and a majority of such wells were back on production in early September 2020. We have also suspended our capital expenditures indefinitely.

Going Concern

Our present level of indebtedness and the recent commodity price environment present challenges to our ability to comply with certain covenants in our credit facilities, and under applicable auditing standards, the independent accountants' opinion on our financial statements for the year ended December 31, 2020 contains an explanatory paragraph regarding the Company's ability to continue as a "going concern." At December 31, 2020, we had a total of $95.0 million outstanding under our First Lien Credit Facility, $112.7 million under our Second Lien Credit Facility, and total indebtedness of $220.5 million including a $10.0 million exit fee. As of September 30, 2021, we had a total of $81.7 million outstanding under our First Lien Credit Facility, $137.1 million under our Second Lien Credit Facility, including a $10.0 million exit fee, and total indebtedness of $221.4 million. Additionally, we have a liability of approximately $9.2 million related to the termination of our hedging agreements. If interest expense increases as a result of higher interest rates or increased borrowings, more cash flow from operations would be used to meet debt service requirements.

Specifically, with regard to our credit agreements, we did not satisfy the first lien debt to consolidated EBITDAX ratio covenant under our First Lien Credit Facility as of the December 31, 2020 measurement date and such failure represented an event of default under our First Lien Credit Facility. In addition, it was anticipated that we would not maintain compliance with the Second Lien Credit Facility total leverage ratio covenant or the minimum asset coverage ratio (as defined in Note 5) both of which were to be first tested as of September 30, 2021, for the required twelve month period and, accordingly, the audit report prepared by our auditors with respect to the financial statements in our Form 10-K for the year ended December 31, 2020 included an explanatory paragraph expressing uncertainty as to our ability to continue as a "going concern". The inability to maintain compliance with certain covenants of our Second Lien Credit Facility represents an additional default under our First Lien Credit Facility as of the end of any such future fiscal quarters. The consolidated financial statements do not include any adjustments that might result from the outcome of the "going concern" uncertainty.

The existing defaults at March 31, 2021 were subject to forbearance agreements with our lenders that expired on May 6, 2021. If the Company's lenders accelerate the payment of amounts outstanding under its credit facilities, the Company does not currently have sufficient liquidity to repay such indebtedness and would need additional sources of capital to do so. The Company could attempt to obtain additional sources of capital from asset sales, public or private issuances of debt, equity or equity-linked securities, debt for equity swaps, or any combination thereof. However, the Company cannot provide any assurances that it will be successful in obtaining capital from such transactions on acceptable terms, or at all.

Under applicable accounting principles these circumstances are deemed to create substantial doubt regarding the Company's ability to continue as a "going concern". The consolidated financial statements have been prepared on a "going concern" basis, which contemplates the realization of assets and the satisfaction of liabilities and other commitments in the normal course of business for the twelve-month period following the date of issuance of these consolidated financial statements. As such, the accompanying consolidated financial statements do not include any adjustments relating to the recoverability and classification of assets and their carrying amount, or the amount and classification of liabilities that may result should the Company be unable to continue as a "going concern".

The Company has continued its previously announced investigation of strategic alternatives and is in discussions with its creditors in an effort to restructure its balance sheet. Any negotiated transaction with its lenders would likely include a sale of a significant block of assets, the proceeds from which would be applied to reduce debt, the exchange of a significant amount of equity interests in the Company for outstanding indebtedness, and/or other possible negotiated transactions, which in the aggregate could eliminate or substantially reduce the outstanding indebtedness under its First Lien Credit facility and Second Lien Credit Facility and result in significant dilution of existing stockholder interests and reduction or potentially elimination of value for existing stockholders. Any such transaction could involve a proceeding under the U.S. Bankruptcy Code. No assurance can be provided that any such potential transactions can be successfully concluded, in which event the Company's lenders could commence foreclosure proceedings seeking to liquidate Company assets to repay the outstanding indebtedness. In any such foreclosure proceedings, it is unlikely that stockholders would recover more than a de minimis amount for their stock, and the stock could become worthless.

In April 2021, we received notice that certain of our hedging agreements were being terminated as a result of events of default under the First Lien Credit Facility, and we voluntarily terminated most of our other hedging arrangements. As a result of the settlement of the terminated hedges, we have outstanding obligations of $9.2 million. These obligations were added to the outstanding balance under our First Lien Credit Facility and will accrue interest at the default interest rate, currently 8.75%, until repaid. Our remaining hedging agreement may also be terminated as a result of such events of default. The settlement of terminated hedging agreements may result in losses and limit our ability to reduce exposure to adverse fluctuations in oil and gas prices. See Note 10 "Events of Default" for current information regarding non-compliance with certain covenants.

Consolidation Principles

The terms "Abraxas," "Abraxas Petroleum," "we," "us," "our" or the "Company" refer to Abraxas Petroleum Corporation and all of its subsidiaries, including Raven Drilling, LLC ("Raven Drilling").

Rig Accounting

In accordance with SEC Regulation S-X, no income is recognized in connection with contractual drilling services performed in connection with properties in which we or our affiliates hold an ownership, or other economic interest. Any income not recognized as a result of this limitation is credited to the full cost pool and recognized through lower amortization as reserves are produced.

Use of Estimates

The preparation of financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of the financial statements and reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Stock-Based Compensation, Option Plans and Warrants

Stock Options

We currently utilize a standard option-pricing model (i.e., Black-Scholes) to measure the fair value of stock options granted to employees and directors.

The following table summarizes our stock option activity for the nine months ended September 30, 2021, (in thousands):

	Number of Shares	Weighted Average Option Exercise Price Per Share	Weighted Average Grant Date Fair Value Per Share
Outstanding, December 31, 2020	196	$ 49.69	$ 35.03
Cancelled/Forfeited	(125)	$ 43.38	$ 30.90
Expired	(17)	$ 82.91	$ 62.02
Balance, September 30, 2021	54	$ 53.79	$ 36.81

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Restricted Stock Awards

Restricted stock awards are awards of common stock that are subject to restrictions on transfer and to a risk of forfeiture if the recipient of the award terminates employment with us prior to the lapse of the restrictions. The fair value of such stock was determined using the closing price on the grant date and compensation expense is recorded over the applicable vesting periods.

The following table summarizes our restricted stock activity for the nine months ended September 30, 2021:

	Number of Shares (thousands)		Weighted Average Grant Date Fair Value Per Share
Unvested, December 31, 2020	41	$	31.37
Vested/Released	(24)		33.23
Cancelled/Forfeited	(1)		26.80
Unvested, September 30, 2021	16	$	26.80

Performance Based Restricted Stock

We issue performance-based shares of restricted stock to certain officers and employees under the Abraxas Petroleum Corporation Amended and Restated 2005 Employee Long-Term Equity Incentive Plan. The shares will vest in three years from the grant date upon the achievement of performance goals based on our Total Shareholder Return ("TSR") as compared to a peer group of companies. The number of shares which would vest depends upon the rank of our TSR as compared to the peer group at the end of the three-year vesting period and can range from zero percent of the initial grant up to 200% of the initial grant.

The table below provides a summary of Performance Based Restricted Stock as of the date indicated:

	Number of Shares (thousands)		Weighted Average Grant Date Fair Value Per Share
Unvested, December 31, 2020	44	$	33.73
Expired	(16)	$	46.35
Unvested, September 30, 2021	28	$	26.80

Compensation expense associated with the performance based restricted stock is based on the grant date fair value of a single share as determined using a Monte Carlo Simulation model which utilizes a stochastic process to create a range of potential future outcomes given a variety of inputs. As the Compensation Committee intends to settle the performance based restricted stock awards with shares of our common stock, the awards are accounted for as equity awards and the expense is calculated on the grant date assuming a 100% target payout and amortized over the life of the awards.

The following table summarizes stock-based compensation from the various forms of compensation utilized by the Company (in thousands).

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2021		2020		2021		2020	
Options	$	1	$	11	$	(22)	$	73
Restricted stock		211		203		527		675
Performance shares		61		134		275		403
	$	273	$	348	$	780	$	1,151

As of September 30, 2021, substantially all expense related to stock based compensation has been amortized. Options are fully amortized while restricted stock and performance shares have approximately $0.2 million and $0.1 million, respectively, that will be amortized over the remainder of 2021 through April 2022.

Warrants for Common Stock

As of September 30, 2021, outstanding warrants to purchase shares of common stock were as follows:

Issuance Date	Exercisable for	Expiration Date	Exercise Price		Number of Shares
August 11, 2020	Common Stock	August 11, 2025	$	0.20	1,672,290

In connection with the amended Second Lien Credit Agreement, on August 11, 2020, the Company issued a warrant to the lender to purchase a total of 33,445,792 shares of common stock at an exercise price of $0.01 per share. As a result of the October 19, 2020 reverse stock split of the Company's authorized, issued and outstanding shares of common stock at a ratio of 1-for-20, the warrant was adjusted to provide that the lender may purchase a total of 1,672,290 shares of common stock at an exercise price of $0.20 per share. The warrant is exercisable immediately, in whole or in part, at any time on or before five years from the issuance date. The fair value of the warrant was recorded as debt issuance costs, presented in the consolidated balance sheets as a deduction from the carrying amount of the note payable, and is being amortized over the loan term.

Oil and Gas Properties

We follow the full cost method of accounting for oil and gas properties. Under this method, all direct costs and certain indirect costs associated with the acquisition of properties and successful and unsuccessful exploration and development activities are capitalized. Depreciation, depletion, and amortization of capitalized oil and gas properties and estimated future development costs, excluding unproved properties, are based on the unit-of-production method based on proved reserves. Net capitalized costs of oil and gas properties, less related deferred taxes, are limited by country, to the lower of unamortized cost or the cost ceiling, defined as the sum of the present value of estimated future net revenues from proved reserves based on unescalated prices discounted at 10%, plus the cost of properties not being amortized, if any, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any, less related income taxes. Costs in excess of the present value of estimated net revenue from proved reserves discounted at 10% are charged to proved property impairment expense. No gain or loss is recognized upon sale or disposition of oil and gas properties for full cost accounting companies with proceeds accounted for as an adjustment of capitalized cost. An exception to this rule occurs when the adjustment to the full cost pool results in a significant alteration of the relationship between capitalized cost and proved reserves. We apply the full cost ceiling test on a quarterly basis on the date of the latest balance sheet presented. At September 30, 2020, the net capital cost of oil and gas properties exceeded the cost ceiling of our estimated proved reserves resulting in an impairment of $54.6 million and $136.1 million for the three and nine months ended September 30, 2020, respectively. At September 30, 2021, the net capitalized costs of oil and gas properties did not exceed the cost ceiling of our estimated proved reserves.

Restoration, Removal and Environmental Liabilities

We are subject to extensive federal, state and local environmental laws and regulations. These laws regulate the discharge of materials into the environment and may require us to remove or mitigate the environmental effects of the disposal or release of petroleum substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefit are expensed.

Liabilities for expenditures of a non-capital nature are recorded when environmental assessments and/or remediation is probable, and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments for the liability or component is fixed or reliably determinable.

We account for future site restoration obligations based on the guidance of ASC 410 which addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. ASC 410 requires that the fair value of a liability for an asset's retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the estimated useful life of the related asset. For all periods presented, we have included estimated future costs of abandonment and dismantlement in our full cost amortization base and amortize these costs as a component of our depletion expense in the accompanying condensed consolidated financial statements.

The following table summarizes our future site restoration obligation transactions for the nine months ended September 30, 2021 and the year ended December 31, 2020 (in thousands):

	September 30, 2021	December 31, 2020
Beginning future site restoration obligation	$ 7,360	$ 7,420
New wells placed on production and other	1	43
Deletions related to property sales	(2,845)	(216)
Deletions related to plugging costs	(336)	(235)
Accretion expense	255	414
Revisions and other	313	(66)
Ending future site restoration obligation	$ 4,748	$ 7,360

In April 2021, the Company divested various non-Bakken properties in North Dakota and Montana, primarily for plugging liability. The result of the transaction was a decrease of approximately $2.7 million in future site development liability, with a corresponding reduction in the full cost pool.

Recently Adopted Accounting Standards

Effective January 1, 2020, the Company adopted Accounting Standards Update ("ASU") 2016-13 and its related amendments. This ASU primarily applies to the Company's accounts receivable, of which the majority are due within 30 days. The Company monitors the credit quality of its counterparties through review of collections, credit ratings, and other analysis. The Company develops its estimated allowance for credit losses primarily using an aging method and analysis of historical loss rates as well as consideration of current and future conditions that could impact its counterparties' credit quality and liquidity. The adoption and implementation of this ASU did not have a material impact on the Company's financial statements.

Recently Issued Accounting Standards

In March 2020, the FASB issued ASU No. 2020-04, "Reference Rate Reform (Topic 840): 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., London Interbank Offered Rate ("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. This ASU was effective upon the issuance and its optional relief can be applied through December 31, 2022. The Company will consider this optional guidance prospectively, if applicable.

In May 2020, the SEC adopted final rules that amend the financial statement requirements for significant business acquisitions and dispositions. Among other changes, the final rules modify the significance tests and improve the disclosure requirements for acquired or to be acquired businesses and related pro forma financial information, the periods those financial statements must cover, and the form and content of the pro forma financial information. The final rules do not modify requirements for the acquisition and disposition of significant amounts of assets that do not constitute a business. The final rules are effective January 1, 2021, but earlier compliance is permitted. The Company will consider these final rules and update its disclosures, as applicable.

2. Reverse Stock Split

On October 19, 2020, the Company effected a 1-for-20 reverse stock split of its issued and outstanding shares of common stock, $0.01 par value. The Company effected the reverse stock split pursuant to the Company's filing of a Certificate of Change with the Secretary of State of the State of Nevada on September 29, 2020. Under Nevada law, no amendment to the Company's Articles of Incorporation was required in connection with the reverse stock split. The Company was authorized to issue 400,000,000 shares of common stock. As a result of the reverse stock split, the Company is authorized to issue 20,000,000 shares of common stock. As a result of the reverse split, 168,069,305 outstanding shares of the Company's common stock were exchanged for approximately 8,421,910 shares of the Company's common stock (subject to adjustment due to the effect of rounding fractional shares into whole shares). The reverse stock split did not have any effect on the stated par value of the common stock. All per share amounts and number of shares in the condensed consolidated financial statements and related notes have been retroactively restated to reflect the reverse stock split.

Additionally on October 19, 2020, all options, warrants and other convertible securities of the Company outstanding immediately prior to the reverse stock split were adjusted by dividing by 20 the number of shares of common stock into which the options, warrants and other convertible securities are exercisable or convertible, and multiplying the exercise or conversion price thereof by 20, all in accordance with the terms of the plans, agreements or arrangements governing such options, warrants and other convertible securities and subject to rounding to the nearest whole share.

The common stock began trading on a split-adjusted basis on the NASDAQ at the market open on October 19, 2020. The trading symbol for the common stock remains "AXAS". On July 26, 2021, the Company received a notice from the Nasdaq Stock Market LLC that the Company's common stock would be suspended. The Company's securities were subsequently suspended from trading on NASDAQ on August 4, 2021 and removed from listing and registration on September 17, 2021, and are currently listed on the OTCQX market place.

3. Revenue from Contracts with Customers

Revenue Recognition

Sales of oil, gas and natural gas liquids ("NGL") are recognized at the point in time when control of the product is transferred to the customer and collectability is reasonably assured. Our contracts' pricing provisions are tied to a market index, with certain adjustments based on, among other factors, physical location, quality of the oil or gas, and prevailing supply and demand conditions. As a result, the price of the oil, gas and NGL fluctuates to remain competitive with other available oil, gas and NGL supplies in the market. We believe that the pricing provisions of our oil, gas and NGL contracts are customary in the industry.

Oil sales

Our oil sales contracts are generally structured such that we sell our oil production to a purchaser at a contractually specified delivery point at or near the wellhead. The crude oil production is priced on the delivery date based upon prevailing index prices less certain deductions related to oil quality, physical location and transportation costs incurred by the purchaser subsequent to delivery. We recognize revenue when control transfers to the purchaser upon delivery at or near the wellhead at the net price received from the purchaser.

Gas and NGL Sales

Under our gas processing contracts, we deliver wet gas to a midstream processing entity at the wellhead or the inlet of the midstream processing entity's system. The midstream processing entity processes the natural gas and remits proceeds to us based upon either (i) the resulting sales price of NGL and residue gas received by the midstream processing entity from third party customers, or (ii) the prevailing index prices for NGL and residue gas in the month of delivery to the midstream processing entity. Gathering, processing, transportation and other expenses incurred by the midstream processing entity are typically deducted from the proceeds that we receive.

In these scenarios, we evaluate whether the midstream processing entity is the principal or the agent in the transaction. In our gas purchase contracts, we have concluded that the midstream processing entity is the agent, and thus, the midstream processing entity is our customer. Accordingly, we recognize revenue upon delivery to the midstream processing entity based on the net amount of the proceeds received from the midstream processing entity.

Disaggregation of Revenue

We are focused on the development of oil and natural gas properties primarily located in the following two operating regions in the United States: (i) the Permian/Delaware Basin, and (ii) Rocky Mountain. Revenue attributable to each of those regions is disaggregated in the tables below.

	Three Months Ended September 30,					
	2021			2020		
	Oil	Gas	NGL	Oil	Gas	NGL
Operating Regions:						
Permian/Delaware Basin	$ 8,341	$ 1,232	$ 724	$ 7,676	$ 77	$ 52
Rocky Mountain	$ 7,165	$ 1,183	$ 2,209	$ 4,790	$ (2)	$ -

	Nine Months Ended September 30,					
	2021			2020		
	Oil	Gas	NGL	Oil	Gas	NGL
Operating Regions:						
Permian/Delaware Basin	$ 23,906	$ 3,096	$ 1,412	$ 16,748	$ 111	$ 62
Rocky Mountain	$ 21,293	$ 2,248	$ 4,004	$ 13,223	$ 72	$ 90

Significant Judgments

Principal versus agent

We engage in various types of transactions in which midstream entities process our gas and subsequently market resulting NGL and residue gas to third-party customers on our behalf, such as our percentage-of-proceeds and gas purchase contracts. These types of transactions require judgment to determine whether we are the principal or the agent in the contract and, as a result, whether revenues are recorded gross or net.

Transaction price allocated to remaining performance obligations

A significant number of our product sales are short-term in nature with a contract term of one year or less. For those contracts, we have utilized the practical expedient in ASC Topic 606-10-50-14 exempting us from 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.

For product sales that have a contract term greater than one year, we have utilized the practical expedient in ASC Topic 606-10-50-14(a) which states we are not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these sales contracts, each unit of product generally represents a separate performance obligation; therefore, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligations is not required.

Contract balances

Under our product sales contracts, we are entitled to payment from purchasers once our performance obligations have been satisfied upon delivery of the product, at which point payment is unconditional. We record invoiced amounts as “Accounts receivable - Oil and gas production sales” in the accompanying condensed consolidated balance sheet.

To the extent actual volumes and prices of oil and natural gas are unavailable for a given reporting period because of timing or information not received from third parties, the expected sales volumes and prices for those properties are estimated and also recorded as “Accounts receivable - Oil and gas production sales” in the accompanying condensed consolidated balance sheets. In this scenario, payment is also unconditional, as we have satisfied our performance obligations through delivery of the relevant product. As a result, we have concluded that our product sales do not give rise to contract assets or liabilities under ASU 2014-09. At September 30, 2021 and December 31, 2020, our receivables from contracts with customers were $13.3 million and $8.8 million, respectively.

Prior-period performance obligations

We record revenue in the month production is delivered to the purchaser. However, settlement statements for certain gas and NGL sales may not be received for 30 to 60 days after the date production is delivered, and as a result, we are required to estimate the amount of production that was delivered to the midstream purchaser and the price that will be received for the sale of the product. Additionally, to the extent actual volumes and prices of oil are unavailable for a given reporting period because of timing or information not received from third party purchasers, the expected sales volumes and prices for those barrels of oil are also estimated.

We record the differences between our estimates and the actual amounts received for product sales in the month that payment is received from the purchaser. Any identified differences between our revenue estimates and actual revenue received historically have not been significant. For the three and nine months ended September 30, 2021 and 2020, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

4. Income Taxes

Deferred tax assets and liabilities are determined based on differences between financial reporting and tax basis of assets and liabilities and are measured using the tax rates and laws expected to be in effect when the differences are expected to reverse.

For the three and nine months ended September 30, 2021, and 2020, there was no income tax benefit due to net operating loss carryforwards (“NOLs”) and we recorded a full valuation allowance against our net deferred tax asset.

At December 31, 2020, we had, subject to the limitation discussed below, $245.2 million of pre-2018 NOLs and $137.8 million of post 2018 NOL carryforwards for U.S. tax purposes. Our pre-2018 NOLs will expire in varying amounts from 2022 through 2037, if not utilized. Any NOLs arising in 2018, 2019, and 2020 can generally be carried back five years, carried forward indefinitely and can offset 100% of taxable income for tax years 2020 and up to 80% of future taxable income for tax years after December 31, 2020. Any NOLs arising on or after January 1, 2021 can generally be carried forward indefinitely and can offset up to 80% of future taxable income. The use of our NOLs will be limited if there is an “ownership change” in our common stock, generally a cumulative ownership change exceeding 50% during a three year period, as determined under Section 382 of the Internal Revenue Code. As of September 30, 2021, we have not had an ownership change as defined by Section 382.

Given historical losses, uncertainties exist as to the future utilization of the NOL carryforwards. Therefore, we established a valuation allowance of $117.3 million for deferred tax assets at December 31, 2020.

As of September 30, 2021, we did not have any accrued interest or penalties related to uncertain tax positions. The tax years 2015 through 2020 remain open to examination by the tax jurisdictions to which we are subject.

The Coronavirus Aid, Relief, and Economic Security Act that was enacted March 27, 2020 includes income tax provisions that allow NOLs to be carried back, allow interest expense to be deducted up to a higher percentage of adjusted taxable income, and modify tax depreciation of qualified improvement property, among other provisions. These provisions have no material impact on the Company.

5. Long-Term Debt

The following sections regarding the First Lien Credit Facility and Second Lien Credit Facility are qualified in their entirety by the disclosure contained in Note 1. Going Concern. Due to certain covenant violations under our credit facilities as of December 31, 2020, and the potential for future violations, all of the debt related to our credit facilities has been classified as current liabilities.

The following is a description of our debt as of September 30, 2021 and December 31, 2020 (in thousands):

	September 30, 2021	December 31, 2020
First Lien Credit Facility	$ 81,689	$ 95,000
Second Lien Credit Facility	127,101	112,695
Exit fee - Second Lien Credit Facility	10,000	10,000
Real estate lien note	2,590	2,810
	221,380	220,505
Less current maturities	(209,434)	(202,751)
	11,946	17,754
Deferred financing fees and debt issuance cost, net	(9,662)	(15,239)
Total long-term debt, net of deferred financing fees and debt issuance costs	$ 2,284	$ 2,515

First Lien Credit Facility

The Company has a senior secured First Lien Credit Facility with Société Générale, as administrative agent and issuing lender, and certain other lenders. As of September 30, 2021, $81.7 million was outstanding under the First Lien Credit Facility.

Outstanding amounts under the First Lien Credit Facility accrue interest at a rate per annum equal to (i) for borrowings that we elect to accrue interest at the reference rate at the greater of (x) the reference rate announced from time to time by Société Générale, (y) the federal funds rate plus 0.5%, and (z) daily one-month LIBOR plus, in each case, 1.5%-2.5%, depending on the utilization of the borrowing base, and (ii) for borrowings that we elect to accrue interest at the Eurodollar rate, LIBOR plus 2.5%-3.5% depending on the utilization of the borrowing base.
However, at any time an event of default exists, the default rate is 3.0% plus the amounts set forth above. At September 30, 2021, the interest rate on the First Lien Credit Facility was approximately 8.75%.

Subject to earlier termination rights and events of default, the stated maturity date of the First Lien Credit Facility is May 16, 2022. Interest is payable quarterly on reference rate advances and not less than quarterly on LIBOR advances. The Company is permitted to terminate the First Lien Credit Facility and is able, from time to time, to permanently reduce the lenders’ aggregate commitment under the First Lien Credit Facility in compliance with certain notice and dollar increment requirements.

Each of the Company’s subsidiaries has guaranteed our obligations under the First Lien Credit Facility on a senior secured basis. Obligations under the First Lien Credit Facility are secured by a first priority perfected security interest, subject to certain permitted encumbrances, in all of the Company and its subsidiary guarantors’ material property and assets. As of September 30, 2021, the collateral is required to include properties comprising at least 90% of the PV-9 of the Company’s proven reserves and 95% of the PV-9 of the Company’s PDP reserves.

Under the amended First Lien Credit Facility, the Company is subject to customary covenants, including financial covenants and reporting covenants. The amendment to the First Lien Credit Facility dated June 25, 2020 (the “1L Amendment”) modified certain provisions of the First Lien Credit Facility, including (i) the addition of monthly mandatory prepayments from excess cash (defined as available cash minus certain cash set-asides and a $3.0 million working capital reserve) with corresponding reductions to the borrowing base; (ii) the elimination of scheduled redeterminations (which were previously made every six months) and interim redeterminations (which were previously made at the request of the lenders no more than once in the six month period between scheduled redeterminations) of the borrowing base; (iii) the replacement of total debt leverage ratio and minimum asset ratio covenants with a first lien debt leverage ratio covenant (comparing the outstanding debt of the First Lien Credit Facility to the consolidated EBITDAX of the Company and requiring that the ratio not exceed 2.75 to 1.00 as of the last day of each fiscal quarter) and a minimum first lien asset coverage ratio covenant (comparing the sum of, without duplication, (A) the PV-15 of producing and developed proven reserves of the Company, (B) the PV-9 of the Company’s hydrocarbon hedging agreements and (C) the PV-15 of proved reserves of the Company classified as “drilled uncompleted” (up to 20% of the sum of (A), (B) and (C)) to the outstanding debt of the First Lien Credit Facility and requiring that the ratio exceed 1.15 to 1.00 as of the last day of each fiscal quarter ended on or before December 31, 2020, and 1.25 to 1.00 for fiscal quarters ending thereafter); (iv) the elimination of current ratio and interest coverage ratio covenants; (v) additional restrictions on (A) capital expenditures (limiting capital expenditures to $3.0 million in any four fiscal quarter period (commencing with the four fiscal quarter period ended June 30, 2020 and calculated on an annualized basis for the 1, 2 and 3 quarter periods ended on June 30, 2020, September 30, 2020 and December 31, 2020, respectively, subject to certain exceptions, including capital expenditures financed with the proceeds of newly permitted, structurally subordinated debt and capital expenditures made when (1) the first lien asset coverage ratio is at least 1.60 to 1.00, (2) the Company is in compliance with the first lien leverage ratio, (3) the amounts outstanding under the First Lien Credit Facility are less than $50.0 million, (4) no default exists under the First Lien Credit Facility, and (5) and all representations and warranties in the First Lien Credit Facility and the related credit documents are true and correct in all material respects), (B) outstanding accounts payable (limiting all outstanding and undisputed accounts payable to $7.5 million, undisputed accounts payable outstanding for more than 60 days to $2.0 million and undisputed accounts payable outstanding for more than 90 days to $1.0 million and (C) general and administrative expenses (limiting cash general and administrative expenses the Company may make or become legally obligated to make in any four fiscal quarter period to $9.0 million for the four fiscal quarter period ended June 30, 2020, $8.25 million for the four fiscal quarter period ended September 30, 2020, $6.9 million for the four fiscal quarter period ended December 31, 2020, and $6.5 million for the fiscal quarter from March 31, 2021 through December 31, 2021 and $5.0 million thereafter; in all cases, general and administrative expense excludes up to $1.0 million in certain legal and professional fees; and (vi) permission for up to an additional $25.0 million in structurally subordinated debt to finance capital expenditures. Under the 1L Amendment, the borrowing base was adjusted to $102.0 million.

The borrowing base will be reduced by any mandatory prepayments from excess cash flow (in an amount equal to such prepayment) and upon the disposition of the Company’s oil and gas properties. At September 30, 2021, the Company’s borrowing base was $81.7 million, the amount outstanding on the First Lien Credit Facility, and thus the Company had no further borrowings available.

As of September 30, 2021, we were not in compliance with the financial covenants under the First Lien Credit Facility, as amended. See Note 10 “Events of Default” for details.

The First Lien Credit Facility contains a number of covenants that, among other things, restrict our ability to:

- incur or guarantee additional indebtedness;
- transfer or sell assets;
- create liens on assets;
- pay dividends or make other distributions on capital stock or make other restricted payments;
- engage in transactions with affiliates other than on an “arm’s length” basis;
- make any change in the principal nature of our business; and
- permit a change of control.

The First Lien Credit Facility also contains customary events of default, including nonpayment of principal or interest, violations of covenants, cross default and cross acceleration to certain other indebtedness, bankruptcy and material judgments and liabilities.

Events of default have occurred under the First Lien Credit Facility as a result of (i) our failure to timely deliver audited financial statements without a “going concern” or like qualification for the fiscal year ended December 31, 2020, (ii) our inability to comply with the first lien debt to consolidated EBITDAX ratio for the fiscal quarter ended December 31, 2020, (iii) our failure to cause certain deposit accounts to be subject to control agreements in favor of the administrative agent for the First Lien Credit Facility and (iv) certain cross-defaults that have occurred, or may occur, as a result of the events of default under the First Lien Credit Agreement and corresponding cross-defaults under the Second Lien Credit Facility and cross-defaults or similar termination events under our hedging contracts. See Note 10 “Events of Default” for details.

Second Lien Credit Facility

On November 13, 2019, we entered into the Term Loan Credit Agreement, with Angelo Gordon Energy Servicer, LLC, as administrative agent, and certain other lenders party thereto, which we refer to as the Second Lien Credit Facility. The Second Lien Credit Facility was amended on June 25, 2020. The Second Lien Credit Facility has a maximum commitment of $100.0 million. As of September 30, 2021, the outstanding balance on the Second Lien Credit Facility was $137.1 million, which includes a $10.0 million exit fee.

The stated maturity date of the Second Lien Credit Facility is November 13, 2022. Prior to the latest amendments of the Second Lien Credit Facility, accrued interest was payable quarterly on reference rate loans and at the end of each three-month interest period on Eurodollar loans. We are permitted to prepay the loans in whole or in part, in compliance with certain notice and dollar increment requirements.

Each of our subsidiaries has guaranteed our obligations under the Second Lien Credit Facility. Obligations under the Second Lien Credit Facility are secured by a first priority perfected security interest, subject to certain permitted liens, including those securing the indebtedness under the First Lien Credit Facility to the extent permitted by the Intercreditor Agreement, of even date with the Second Lien Credit Facility, among us, our subsidiaries, Angelo Gordon Energy Servicer, LLC and Société Générale, in all of our subsidiary guarantors’ material property and assets. As of September 30, 2021, the collateral is required to include properties comprising at least 90% of the PV-9 of the Company’s proven reserves and 95% of the PV-9 of the Company’s PDP reserves.

Under the amended Second Lien Credit Facility, the Company is subject to customary covenants, including financial covenants and reporting covenants. The amendment to the Second Lien Credit Facility dated June 25, 2020 (the "2L Amendment") modified certain provisions of the Second Lien Credit Facility, including (i) a requirement that, while the obligations under the First Lien Credit Facility are outstanding, scheduled payments of accrued interest under the Second Lien Credit Facility will be paid in the form of capitalized interest; (ii) an increase in the interest rate by 200bps for interest payable in cash and 500bps for interest payable in kind; (iii) modification of the minimum asset ratio covenant to be the sum of, without duplication, (A) the PV-15 of producing and developed proven reserves of the Company, (B) the PV-9 of the Company's hydrocarbon hedging agreements and (C) the PV-15 of proved reserves of the Company classified as "drilled uncompleted" (up to 20% of the sum of (A), (B) and (C)) to the total outstanding debt of the Company and requiring that the ratio not exceed 1.45 to 1.00 as of the last day of each fiscal quarter ending between September 30, 2021 to December 31, 2021, and 1.55 to 1.00 for fiscal quarters ending thereafter); (iv) modification of the total leverage ratio covenant to set the first test date which occurred on September 30, 2021; (v) modification of the current ratio to eliminate the exclusion of certain valuation accounts associated with hedging agreements from current assets and from current liabilities, (vi) additional restrictions on (A) capital expenditures (limiting capital expenditures to those expenditures set forth in a plan of development approved by Angelo Gordon Energy Servicer, LLC, subject to certain exceptions, including capital expenditures financed with the proceeds of newly permitted, structurally subordinated debt), (B) outstanding accounts payable (limiting all outstanding and undisputed accounts payable to $7.5 million, undisputed accounts payable outstanding for more than 60 days to $2.0 million and undisputed accounts payable outstanding for more than 90 days to $1.0 million and (C) general and administrative expenses (limiting cash general and administrative expenses the Company may make or become legally obligated to make in any four fiscal quarter period to $9.0 million for the four fiscal quarter period ended June 30, 2020, $8.25 million for the four fiscal quarter period ended September 30, 2020, $6.5 million for fiscal quarter period from March 31, 2021 through December 31, 2021 and $5.0 million thereafter.

As of September 30, 2021, we were not in compliance with the financial covenants under the Second Lien Credit Facility, as amended. See Note 10 "Events of Default" for details.

The Second Lien Credit Facility contains a number of covenants that, among other things, restrict our ability to:

- incur or guarantee additional indebtedness;
- transfer or sell assets;
- create liens on assets;
- pay dividends or make other distributions on capital stock or make other restricted payments;
- engage in transactions with affiliates other than on an "arm's length" basis;
- make any change in the principal nature of our business; and
- permit a change of control.

The Second Lien Credit Facility also contains customary events of default, including nonpayment of principal or interest, violation of covenants, cross default and cross acceleration to certain other indebtedness, bankruptcy and material judgments and liabilities.

Events of default have occurred under the Second Lien Credit Facility as a result of (i) our failure to timely deliver audited financial statements without a "going concern" or like qualification for the fiscal year ended December 31, 2020, (ii) our failure to cause certain deposit accounts to be subject to control agreements in favor of the administrative agent for the Second Lien Credit Facility, (iii) the failure of the Company to meet certain hedging requirements, and (iv) certain cross-defaults that have occurred, or may occur, as a result of the occurrence of events of default under the First Lien Credit Facility and the Second Lien Credit Facility and corresponding cross-defaults or similar termination events under our hedging contracts. Additional events of default have occurred as of September 30, 2021, as a result of our failure to comply with certain financial covenants under the Second Lien Credit Facility, as amended. See Note 10 "Events of Default" for details

On April 16, 2021, we received a Notice of Default and Reservation of Rights (the "Notice of Default") from Angelo Gordon stating that we have defaulted under the Second Lien Credit Facility, and that, as a result, the lenders have accelerated our obligations due thereunder and have reserved their rights to pursue additional remedies in the future.

The Notice of Default declares that our obligations under the Second Lien Credit Facility are immediately due and payable, in each case without presentment, demand, protest or other requirements of any kind, and have begun to bear interest at the rate applicable to such amount under the Second Lien Credit Facility, plus an additional 3%. Additionally, the administrative agent and the lenders have reserved their right to exercise further rights, powers and remedies under the Second Lien Credit Facility, at any time or from time to time, with respect to any of the events of default described above. Angelo Gordon agreed to forbear from exercising remedies available to it until May 6, 2021. We are in discussions with Angelo Gordon regarding further forbearance, but no assurance can be provided that we will be able to enter into any additional forbearance agreements.

Real Estate Lien Note

We have a real estate lien note secured by a first lien deed of trust on the property and improvements which serves as our corporate headquarters. The outstanding principal accrues interest at a fixed rate of 4.9%. The note is payable in monthly installments of principal and accrued interest in the amount of $35,672. The maturity date of the note is July 20, 2023. As of September 30, 2021 and December 31, 2020, $2.6 million and $2.8 million, respectively, were outstanding on the note.

Pending Discussions Regarding Debt Restructurings

The Company is in discussions with its creditors in an effort to restructure its balance sheet and eliminate or substantially reduce the outstanding indebtedness under its First Lien Credit Facility and Second Lien Credit Facility. Any negotiated transaction with its lenders would likely include the possible sale of a significant block of assets, the proceeds from which would be applied to reduce debt, the exchange of a significant amount of equity interests in the Company for outstanding indebtedness, and/or other possible negotiated transactions, which in the aggregate would likely result in significant dilution of existing stockholder interests and reduction or potentially elimination of value for existing stockholders. Any such transaction could involve a proceeding under the U.S. Bankruptcy Code. No assurance can be provided that any such transaction can be successfully concluded, in which event the Company's lenders may commence foreclosure proceedings seeking to liquidate Company assets to repay the outstanding indebtedness. In any such proceeding, it is unlikely that stockholders would recover any more than a de minimis amount for their stock, and the stock may become worthless.

6. Earnings per Share

The following table sets forth the computation of basic and diluted earnings per share:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Numerator:				
Net loss	$ (1,245)	$ (73,615)	$ (38,940)	$ (115,428)
Denominator:				
Denominator for basic earnings per share – weighted-average common shares outstanding	8,406	8,362	8,406	8,366
Effect of dilutive securities:				
Stock options, restricted shares and warrants	-	-	-	-
Denominator for diluted earnings per share – adjusted weighted-average shares and assumed exercise of options and restricted shares	8,406	8,362	8,406	8,366
Net loss per common share - basic	$ (0.15)	$ (8.80)	$ (4.63)	$ (13.80)
Net loss per common share - diluted	$ (0.15)	$ (8.80)	$ (4.63)	$ (13.80)

Basic earnings per share, excluding any dilutive effects of stock options and unvested restricted stock, is computed by dividing net income available to common stockholders by the weighted average number of common shares outstanding for the period. Diluted net income per share is computed similar to basic; however diluted income per share reflects the assumed conversion of all potentially dilutive securities. For the three and nine month periods ended September 30, 2021 there were no dilutive potential shares relating to stock options and restricted stock due to our depressed stock price and losses in the period.

7. Hedging Program and Derivatives

The derivative contracts we utilize are based on index prices that may and often differ from the actual oil and gas prices realized in our operations. Our derivative contracts do not qualify for hedge accounting; therefore, fluctuations in the market value of the derivative contracts are recognized in earnings during the current period. There are no netting agreements relating to these derivative contracts and there is no policy to offset.

The following table sets forth the summary position of our derivative contracts as of September 30, 2021:

	Oil - WTI	
Contract Periods	Daily Volume (Bbl)	Swap Price (per Bbl)
Fixed Swaps		
2021 October - December	750	$ 52.50

Substantially all of our hedges were terminated in April 2021.

The following table illustrates the impact of derivative contracts on our balance sheet:

Fair Value of Derivative Contracts as of September 30, 2021

	Asset Derivatives		Liability Derivatives	
Derivatives not designated as hedging instruments	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity price derivatives	Derivatives – current	$ -	Derivatives – current	$ 2,017
Commodity price derivatives	Derivatives – long-term	-	Derivatives – long-term	-
		$ -		$ 2,017

Fair Value of Derivative Contracts as December 31, 2020

	Asset Derivatives		Liability Derivatives	
Derivatives not designated as hedging instruments	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity price derivatives	Derivatives – current	$ 9,639	Derivatives – current	$ 480
Commodity price derivatives	Derivatives – long-term	10,281	Derivatives – long-term	-
		$ 19,920		$ 480

8. Financial Instruments

Assets and liabilities measured at fair value are categorized into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

- Level 1 – inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 - inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3 - inputs to the valuation methodology are unobservable and significant to the fair value measurement.

A financial instrument's categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability. We are further required to assess the creditworthiness of the counter-party to the derivative contract. The results of the assessment of non-performance risk, based on the counter-party's credit risk, could result in an adjustment of the carrying value of the derivative instrument. The following tables sets forth information about our assets and liabilities measured at fair value on a recurring basis as of September 30, 2021 and December 31, 2020, and indicate the fair value hierarchy of the valuation techniques utilized by us to determine such fair value:

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of September 30, 2021
Assets:				
NYMEX fixed price derivative contracts	$ —	$ —	$ —	$ —
Total Assets	$ —	$ —	$ —	$ —
Liabilities:				
NYMEX fixed price derivative contracts	$ —	$ 2,017	$ —	$ 2,017
Total Liabilities	$ —	$ 2,017	$ —	$ 2,017

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2020
Assets:				
NYMEX fixed price derivative contracts	$ —	$ 19,920	$ —	$ 19,920
Total Assets	$ —	$ 19,920	$ —	$ 19,920
Liabilities:				
NYMEX fixed price derivative contracts	$ —	$ 480	$ —	$ 480
Total Liabilities	$ —	$ 480	$ -	$ 480

As of September 30, 2021, our derivative contracts consisted of NYMEX-based fixed price swaps. At December 31, 2020 our derivative contracts consisted of NYMEX-based fixed price swaps and basis differential swaps. Under fixed price swaps, we receive a fixed price for our production and pay a variable market price to the contract counterparty. Under basis swaps, if the market price is above the fixed price, we pay the counter-party, if the market price is below the fixed price, the counter-party pays us. The NYMEX-based fixed price derivative swaps and basis differential swap contracts are indexed to NYMEX futures contracts, which are actively traded, for the underlying commodity and are commonly used in the energy industry. A number of financial institutions and large energy companies act as counter-parties to these types of derivative contracts. As the fair value of NYMEX-based fixed price swaps are based on a number of inputs, including contractual volumes and prices stated in each derivative contract, current and future NYMEX commodity prices, and quantitative models that are based upon readily observable market parameters that are actively quoted and can be validated through external sources, we have characterized these derivative contracts as Level 2. In order to verify the third party valuation, we enter the various inputs into a model and compare our results to the third party for reasonableness. We did not have any Level 3 contracts at December 31, 2020 or September 30, 2021.

Nonrecurring Fair Value Measurements

Non-financial assets and liabilities measured at fair value on a nonrecurring basis included certain non-financial assets and liabilities as may be acquired in a business combination and thereby measured at fair value and the initial recognition of asset retirement obligations for which fair value is used. Unproved oil and gas properties are assessed periodically, at least annually, to determine whether impairment has occurred. The assessment considers the following factors, among others: intent to drill, remaining lease term, geological and geophysical evaluations, drilling results and activity, the assignment of proved reserves, the economic viability of development if proved reserves were assigned and other current market conditions. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization.

The asset retirement obligation estimates are derived from historical costs as well as management's expectation of future cost environments. As there is no corroborating market activity to support the assumptions used, the Company has designated these liabilities as Level 3. A reconciliation of the beginning and ending balances of the Company's asset retirement obligation is presented in Note 1.

Other Financial Instruments

The carrying amounts of our cash, cash equivalents, restricted cash, accounts receivable and accounts payable approximate fair value because of the short-term maturities and/or liquid nature of these assets and liabilities. The carrying value of our debt approximates fair value as the interest rates are market rates and this debt is considered Level 2.

9. Leases

Nature of Leases

We lease certain real estate, field equipment and other equipment under cancelable and non-cancelable leases to support our operations. A more detailed description of our significant lease types is included below.

Field Equipment

We rent various field equipment from third parties in order to facilitate the downstream movement of our production from our drilling operations to market. Our compressor and cooler arrangements are typically structured with a non-cancelable primary term of one year and continue thereafter on a month-to-month basis subject to termination by either party with thirty days' notice. These leases are considered short term and are not capitalized. We have a small number of compressor leases that are longer than twelve months. We have concluded that our equipment rental agreements represent operating leases with a lease term that equals the primary non-cancelable contract term. Upon completion of the primary term, both parties have substantive rights to terminate the lease. As a result, enforceable rights and obligations do not exist under the rental agreement subsequent to the primary term. We enter into daywork contracts for drilling rigs with third parties to support our drilling activities. Our drilling rig arrangements are typically structured with a term that is in effect until drilling operations are completed on a contractually specified well or well pad. Upon mutual agreement with the contractor, we typically have the option to extend the contract term for additional wells or well pads by providing thirty days notice prior to the end of the original contract term. We have concluded that our drilling rig arrangements represent short-term operating leases. The accounting guidance requires us to make an assessment at contract commencement if we are reasonably certain that we will exercise the option to extend the term. Due to the continuously evolving nature of our drilling schedules and the potential volatility in commodity prices in an annual period, our strategy to enter into shorter term drilling rig arrangements allows us the flexibility to respond to changes in our operating and economic environment. We exercise our discretion in choosing to extend or not extend contracts on a rig by rig basis depending on the conditions present at the time the contract expires. At the time of contract commencement, we have determined we cannot conclude with reasonable certainty if we will choose to extend the contract beyond its original term. Pursuant to the full cost method, these costs are capitalized as part of natural gas and oil properties on our balance sheet when paid.

Discount Rate

Our leases typically do not provide an implicit rate. Accordingly, we are required to use our incremental borrowing rate in determining the present value of lease payments based on the information available at commencement date. Our incremental borrowing rate reflects the estimated rate of interest that we would pay to borrow on a collateralized basis over a similar term an amount equal to the lease payments in a similar economic environment. We use the implicit rate in the limited circumstances in which that rate is readily determinable.

Practical Expedients and Accounting Policy Elections

Certain of our lease agreements include lease and non-lease components. For all existing asset classes with multiple component types, we have utilized the practical expedient that exempts us from separating lease components from non-lease components. Accordingly, we account for the lease and non-lease components in an arrangement as a single lease component. In addition, for all of our existing asset classes, we have made an accounting policy election not to apply the lease recognition requirements to our short-term leases (that is, a lease that, at commencement, has a lease term of 12 months or less and does not include an option to purchase the underlying asset that we are reasonably certain to exercise). Accordingly, we recognize lease payments related to our short-term leases in our statement of operations on a straight-line basis over the lease term which has not changed from our prior recognition. To the extent that there are variable lease payments, we recognize those payments in our statement of operations in the period in which the obligation for those payments is incurred. None of our current leases contain variable payments. Refer to 'Nature of Leases" above for further information regarding those asset classes that include material short-term leases.

The components of our total lease expense for the three and nine months ended September 30, 2021, the majority of which is included in lease operating expense, are as follows:

	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2021
Operating lease cost	$ 13	$ 52
Short-term lease expense (1)	$ 465	$ 1,456
Total lease expense	$ 478	$ 1,508
Short-term lease costs (2)	$ -	$ -

(1) Short-term lease expense represents expense related to leases with a contract term of 12 months or less.
(2) These short-term lease costs are related to leases with a contract term of 12 months or less which are related to drilling rigs and are capitalized as part of natural gas and oil properties on our balance sheet.

Supplemental balance sheet information related to our operating leases is included in the table below:

	September 30, 2021
Operating lease ROU assets	$ 184
Operating lease liability - current	$ 41
Operating lease liabilities - long-term	$ 118

Our weighted average remaining lease term and weighted average discount rate for our operating leases are as follows:

	September 30, 2021
Weighted Average Remaining Lease Term (in years)	12.0
Weighted Average Discount Rate	6%

Our lease liabilities with enforceable contract terms that are greater than one year mature as follows:

	Operating Leases
Remainder of 2021	$ 49
2022	42
2023	37
2024	4
2025	4
Thereafter	94
Total lease payments	230
Less imputed interest	(71)
Total lease liability	$ 159

At September 30, 2021, we had only a lease on office equipment, with minimum lease payments with commitments that had initial or remaining lease terms in excess of one year.

10. Events of Default

In connection with the completion of our financial statements for the year ended December 31, 2020, the Company tested its financial ratios for the fiscal quarter ended December 31, 2020 and determined that it was not in compliance the first lien debt to consolidated EBITDAX ratio covenant under the First Lien Credit Facility. Our failure to comply with such covenant contributed to our independent accountant's including an explanatory paragraph with regard to the Company's ability to continue as a "going concern" in issuing their opinion on our financial statements for the year ended December 31, 2020. The "going concern" opinion resulted in an additional event of default under the First Lien Credit Facility and the Second Lien Credit Facility. Additional events of default have occurred as of September 30, 2021, as a result of our failure to comply with certain financial covenants under the Second Lien Credit Facility, as amended. A discussion of the events of default follows.

First Lien Credit Facility

Events of default have occurred under the First Lien Credit Facility as a result of (i) the Company's failure to timely deliver audited financial statements without a "going concern" or like qualification for the fiscal year ended December 31, 2020, (ii) its inability to comply with the first lien debt to consolidated EBITDAX ratio for the fiscal quarter ended December 31, 2020, (iii) our failure to cause certain deposit accounts to be subject to control agreements in favor of the administrative agent for the First Lien Credit Facility, and (iv) certain cross-defaults that have occurred, or may occur, as a result of the events of default under the First Lien Credit Agreement and corresponding cross-defaults under the Second Lien Credit Facility and cross-defaults or similar termination events under our hedging contracts.

Second Lien Credit Facility

Events of default have occurred under the Second Lien Credit Facility as a result of (i) the Company's failure to timely deliver audited financial statements without a "going concern" or like qualification for the fiscal year ended December 31, 2020, (ii) its failure to cause certain deposit accounts to be subject to control agreements in favor of the administrative agent for the Second Lien Credit Facility and (iii) the failure of the Company to meet certain hedging requirements, (iv) the Company's inability to comply with the total leverage ratio for the fiscal quarter ended September 30, 2021, (v) the Company's inability to comply with minimum asset coverage ratio for the fiscal quarter ended September 30, 2021, and (vi) certain cross-defaults that have occurred, or may occur, as a result of the occurrence of events of default under the First Lien Credit Facility and corresponding cross-defaults or similar termination events under our hedging contracts. Additional events of default have occurred as of September 30, 2021, as a result of our failure to comply with certain financial covenants under the Second Lien Credit Facility, as amended.

On April 16, 2021, we received a Notice of Default and Reservation of Rights (the "Notice of Default") from Angelo Gordon stating that we have defaulted under the Second Lien Credit Facility, and that, as a result, the lenders have accelerated our obligations due thereunder and have reserved their rights to pursue additional remedies in the future.

The Notice of Default declares that our obligations under the Second Lien Credit Facility are immediately due and payable, in each case without presentment, demand, protest or other requirements of any kind, and have begun to bear interest at the rate applicable to such amount under the Second Lien Credit Facility, plus an additional 3%. Additionally, the administrative agent and the lenders have reserved their right to exercise further rights, powers and remedies under the Second Lien Credit Facility, at any time or from time to time, with respect to any of the events of default described above. Angelo Gordon agreed to forbear from exercising remedies available to it until May 6, 2021. We are in discussions with Angelo Gordon regarding further forbearance, but no assurance can be provided that we will be able to enter into any additional forbearance agreements.

Hedging Contracts

Effective April 12, 2021, Morgan Stanley Capital Group, Inc. ("Morgan Stanley"), a hedge counterparty to several of our hedging contracts sent us notice of events of default and early termination with respect to the hedging contracts to which they are a counterparty. The notice indicates Morgan Stanley's election to exercise termination rights under the hedge contract, which Morgan Stanley asserts have arisen as a result of the occurrence of events of default under the First Lien Credit Facility, of which Morgan Stanley is a lender, holding approximately 3.7% of the outstanding obligations under the First Lien Credit Facility. The termination value of the hedging agreements with Morgan Stanley as of the effective date of the notice was approximately $9.2 million. We subsequently voluntarily terminated most of our other hedging arrangements. As a result of the settlement of the terminated hedges, we have outstanding obligations of $9.2 million, including the $8.4 million to Morgan Stanley. These obligations will be added to the outstanding balance of the First Lien Credit Facility and accrue interest at the default rate, currently 8.75%, until repaid. Other hedging agreements may also be terminated as a result of the events of default. The termination of additional hedging agreements may result in losses and limit our ability to reduce exposure to adverse fluctuations in oil and gas prices. Amounts that we may owe as a result of terminated hedging agreements will accrue interest for so long as such amounts remain unpaid.

Forbearance Discussions

The existing events of default under the credit facilities were subject to forbearance agreements with our lenders that expired on May 6, 2021. We are in discussions with our lenders regarding further forbearance, but no assurance can be provided that we will be able to enter into any additional forbearance agreements.

11. Commitments and Contingencies

From time to time, we are involved in litigation relating to claims arising out of our operations in the normal course of business. At September 30, 2021, we were not involved in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on our financial position or results of operations.

12. Subsequent Events

As noted in Note 10 above, defaults under our First Lien Credit Facility and Second Lien Credit Facility, and constraints imposed by the lenders in the most recent amendments to those facilities, have deprived us of capital resources necessary to continue to develop our assets and generate cash. As a result, we have virtually no excess cash flow or available capital. While we have sought additional forbearances from our lenders, to date no additional relief has been forthcoming. However, increased energy prices have made the climate more favorable for discussions regarding possible negotiated transactions that would reduce or eliminate our existing long-term indebtedness.

No assurances can be provided that a transaction or transactions can be concluded that will successfully address our outstanding borrowings. However, discussions are currently underway regarding a possible sale of assets to permit payment of the First Lien Credit Facility indebtedness, and a possible debt/equity exchange to extinguish the Second Lien Credit Facility indebtedness in return for the issuance of substantial equity ownership in the Company to the Second Lien Credit Facility lender.

If successfully concluded, these transactions could discharge the Company's long-term indebtedness and permit us to resume development of locations that we believe are highly likely to generate additional production oil and gas.

The amount of outstanding indebtedness under our Second Lien Credit Facility is in excess of $137 million, and if a transaction could be successfully concluded, it would result in substantial dilution of existing stockholder interests, and possibly elimination of value for existing stockholders. No terms have been finalized regarding these possible transactions, and no assurance can be provided that the negotiations will be successful.

In the event a negotiated transaction cannot be concluded, the First Lien Credit Facility Lender may seek to foreclose its liens on the Company's assets, and the Second Lien Credit Facility Lender may seek to foreclose its liens on any remaining assets. If the lenders initiate procedures to seize and sell the Company's assets, the Company would consider initiating a proceeding under the U.S. Bankruptcy Code to give us the opportunity to propose a restructuring plan designed to permit payment of lenders over time and development of the Company's resources for the benefit of the lenders and, if possible, the Company's stockholders. No assurance can be provided regarding the outcome of any contested bankruptcy proceeding, but it is possible, if not likely, that stockholders would recognize no value for their shares.

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

The following is a discussion and analysis of our financial condition, results of operations, liquidity and capital resources and should be read in conjunction with our consolidated financial statements and the notes thereto, included in this Quarterly Report on Form 10-Q and the consolidated financial statements and notes thereto as of and for the year ended December 31, 2020 and the related Management's Discussion and Analysis of Financial Condition and Results of Operations, both of which are contained in our Annual Report on Form 10-K for the year ended December 31, 2020 filed with the SEC on May 6, 2021. Please see "Forward Looking Information" above.

Except as otherwise noted, all tabular amounts are in thousands, except per unit values.

Critical Accounting Policies

There have been no changes from the Critical Accounting Policies described in our Annual Report on Form 10-K for the year ended December 31, 2020, except for the adoption of Accounting Standards Update 2016-13, Financial Instruments - Credit Losses which was effective January 1, 2020. See "Recently Issued Accounting Standards" for more information.

General

We are an independent energy company primarily engaged in the acquisition, development and production of oil and gas in the United States. Historically, we have grown through the acquisition and subsequent development of producing properties, principally through the development of shale or tight oil reservoirs in areas known to be productive of oil and gas utilizing new technologies such as modern log analysis and reservoir modeling techniques as well as 3-D seismic surveys and horizontal drilling and stage fracturing. As a result of these activities, we believe that we have a number of development opportunities on our properties.

COVID-19 Overview

In the first quarter of 2020, a new strain of coronavirus ("COVID-19") emerged, creating a global health emergency that has been classified by the World Health Organization as a pandemic. As a result of the COVID-19 pandemic, consumer demand for both oil and gas decreased as a direct result of travel restrictions placed by governments in an effort to curtail the spread of COVID-19 and its variants. In addition, in March 2020, members of Organization of Petroleum Exporting Countries ("OPEC") failed to agree on production levels, which caused an increased supply of oil and gas and led to a substantial decrease in oil prices and an increasingly volatile market. OPEC agreed to cut global petroleum output but did not go far enough to offset the impact of COVID-19 on demand. As a result of this decrease in demand and increase in supply, the price of oil and gas decreased, which has affected our liquidity. Since that time, demand and the price of oil and gas have increased, but uncertainty related to the pandemic caused by COVID-19 and its variant strains persists.

In early March 2020, global oil and natural gas prices declined sharply, rising in recent months, but may decline again. The full impact of COVID-19 and its variants continues to evolve as of the date of this report. As such, it is uncertain as to the full magnitude that will have on the Company. Management is actively monitoring the global situation and the impact on the Company's future operations, financial position and liquidity in fiscal year 2021. In response to the price volatility, the Company has taken action to reduce general and administrative costs, as well as shutting in production in mid-March 2020, but subsequently started restoring production in mid-June, a majority of such wells were back on production in early September 2020. Principally as a result of restrictions imposed by our lenders, we have also suspended our capital expenditures indefinitely.

Factors Affecting Our Financial Results

Our financial results depend upon many factors which significantly affect our results of operations including the following:

- commodity prices and the effectiveness of our hedging arrangements;
- the level of total sales volumes of oil and gas;
- the availability of and our ability to raise additional capital resources and provide liquidity to meet cash flow needs;
- the level of and interest rates on borrowings; and
- the level and success of exploration and development activity.

Commodity Prices and Hedging Arrangements.

The results of our operations are highly dependent upon the prices received for our oil and gas production. The prices we receive for our production are dependent upon spot market prices, differentials and the effectiveness of our derivative contracts, which we sometimes refer to as hedging arrangements. Substantially all of our sales of oil and gas are made in the spot market, or pursuant to contracts based on spot market prices, and not pursuant to long-term, fixed-price contracts. Accordingly, the prices received for our oil and gas production are dependent upon numerous factors beyond our control. Significant declines in prices for oil and gas could have a material adverse effect on our financial condition, results of operations, cash flows and quantities of reserves recoverable on an economic basis.

As a result of the many uncertainties associated with the world political environment, worldwide supplies of oil, NGL and gas, the availability of other worldwide energy supplies and the relative competitive relationships of the various energy sources in the view of consumers, we are unable to predict what changes may occur in oil, NGL and gas prices in the future. The market price of oil and condensate, NGL and gas largely determines the amount of cash generated from operating activities, which will in turn impact our financial position.

During the nine months ended September 30, 2021, the NYMEX future price for oil averaged $65.04 per Bbl as compared to $37.26 per Bbl in the same period of 2020. During the nine months ended September 30, 2021, the NYMEX future spot price for gas averaged $3.35 per MMBtu compared to $1.81 per MMBtu in the same period of 2020. Prices closed on September 30, 2021 at $75.03 per Bbl of oil and $5.87 per MMBtu of gas, compared to closing on September 30, 2020 at $20.48 per Bbl of oil and $1.64 per MMBtu of gas. On November 11, 2021, prices closed at $81.59 per Bbl of oil and $5.15 per MMBtu of gas. If commodity prices decline, our revenue and cash flow from operations will also likely decline. In addition, lower commodity prices could also reduce the amount of oil and gas that we can produce economically. If oil and gas prices decline, our revenues, profitability and cash flow from operations will also likely decrease which could cause us to alter our business plans, including reducing any then existing drilling activities. Such declines have required, and in future periods could also require us to write down the carrying value of our oil and gas assets which would also cause a reduction in net income. The prices that we receive are also impacted by basis differentials, which can be significant, and are dependent on actual delivery points. Finally, low commodity prices will likely cause a reduction of our proved reserves.

The realized prices that we receive for our production differ from NYMEX futures and spot market prices, principally due to:

- basis differentials which are dependent on actual delivery location;
- adjustments for BTU content;
- quality of the hydrocarbons; and
- gathering, processing and transportation costs.

The following table sets forth our average differentials for the nine month periods ended September 30, 2021 and 2020:

	Oil - NYMEX		Gas - NYMEX	
	2021	2020	2021	2020
Average realized price (1)	$ 60.82	$ 36.88	$ 2.06	$ 0.13
Average NYMEX price	65.04	38.51	3.35	1.92
Differential	$ (4.22)	$ (1.63)	$ (1.29)	$ (1.79)

(1) Excludes the impact of derivative activities.

At September 30, 2021, our remaining derivative contract is a NYMEX-based fixed price swaps. Under fixed price swaps, we receive a fixed price for our production and pay a variable market price to the contract counter-party.

The majority of our derivative contracts were terminated in April 2021. Our remaining derivative contract equates to approximately 33% of the estimated oil production from our net proved developed producing reserves (based on reserve estimates at September 30, 2021 from October 1, 2021 through December 31, 2021. None of our production subsequent to 2021 is covered by derivative contracts. When prevailing market prices are higher than our contract prices, we will not realize increased cash flow. We have in the past and will in the future sustain losses on our derivative contracts if market prices are higher than our contract prices. Conversely, when prevailing market prices are lower than our contract prices, we will sustain gains on our commodity derivative contracts. For the nine months ended September 30, 2021, we realized a loss of $18.7 million on our derivative contracts, including a loss of $7.1 million resulting from the termination of our derivative contracts in April 2021. For the nine months ended September 30, 2020, we realized a gain of $53.2 million on our derivative contracts. We have not designated any of these derivative contracts as hedges as prescribed by applicable accounting rules. Substantially all of our derivative contracts were terminated in April 2021, as a result of our default on our credit facilities. See Note 10 “Events of Default”.

The following table sets forth our derivative contracts at September 30, 2021:

	Oil - WTI	
Contract Periods	Daily Volume (Bbl)	Swap Price (per Bbl)
Fixed Swaps		
2021 October - December	750	$ 52.50

At September 30, 2021, the aggregate fair market value of our commodity derivative contracts was a net liability of approximately $2.0 million.

Most of our derivative contracts were terminated in April 2021.

Production Volumes. Our proved reserves will decline as oil and gas is produced, unless we find, acquire or develop additional properties containing proved reserves or conduct successful exploration and development activities. Based on the reserve information set forth in our reserve report as of December 31, 2020, our average annual estimated decline rate for our net proved developed producing reserves is 39%; 18%; 14%; 13% and 12% in 2021, 2022, 2023, 2024 and 2025, respectively, 9% in the following five years, and approximately 9% thereafter. These rates of decline are estimates and actual production declines could be materially different. While we have had some success in finding, acquiring and developing additional reserves, we have not always been able to fully replace the production volumes lost from natural field declines and property sales. Our ability to acquire or find additional reserves in the future will be dependent, in part, upon the amount of available funds for acquisition, exploration and development projects. In addition, the 1L Amendment limits capex to $3.0 million over any four consecutive quarters beginning with the quarter ended June 30, 2020. This limit is effective until the First Lien Credit Facility is paid down to $50.0 million, which will limit our ability to replace production volumes until the First Lien Credit Facility is substantially reduced or repaid.

We had capital expenditures during the nine months ended September 30, 2021 of $856,000 related to our existing properties. We have not established a capital expenditure budget for 2021 due to restraints imposed by our credit facility, as amended. Management and the board of directors are also considering additional operating and overhead cost efficiencies that could be realized in connection with the 2021 budget. The amendments to our credit facilities, described in the "Liquidity and Capital Resources" section below, limit our capital expenditures to $3.0 million in any four consecutive quarters, beginning with the quarter ended June 30, 2020. Our capital expenditures will not be able to offset oil and gas production decreases caused by natural field declines.

The following table presents historical net production volumes for the three and nine months ended September 30, 2021, and 2020:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Total production (MBoe)	516	492	1,541	1,265
Average daily production (Boepd)	5,605	5,346	5,644	4,616
% Oil	45%	71%	48%	64%

The following table presents our net oil, gas and NGL production, the average sales price per Bbl of oil and NGL and per Mcf of gas produced and the average cost of production per Boe of production sold, for the three and nine months ended September 30, 2021 and 2020, by our major operating regions:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Oil production (MBbls)				
Rocky Mountain	108	138	360	376
Permian/Delaware Basin	122	209	383	437
Total	230	347	743	813
Gas production (MMcf)				
Rocky Mountain	477	331	1,391	966
Permian/Delaware Basin	415	123	1,204	438
Total	892	454	2,595	1,404
NGL production (MBbls)				
Rocky Mountain	107	55	283	168
Permian/Delaware Basin	30	14	82	50
Total	137	69	365	218
Total production (MBoe) (1)	516	492	1,541	1,265
Average sales price per Bbl of oil (2)				
Rocky Mountain	$ 66.08	$ 34.76	$ 59.07	$ 35.13
Permian/Delaware Basin	68.66	36.68	62.48	38.38
Composite	67.44	35.92	60.82	36.88
Average sales price per Mcf of gas (2)				
Rocky Mountain	$ 2.48	$ (0.01)	$ 1.62	$ 0.07
Permian/Delaware Basin	2.97	0.63	2.57	0.25
Composite	$ 2.71	0.17	$ 2.06	0.13
Average sales price per Bbl of NGL				
Rocky Mountain	$ 20.70	$ -	$ 14.14	$ 0.54
Permian/Delaware Basin	23.80	3.74	17.17	1.23
Composite	21.39	0.76	14.83	0.70
Average sales price per Boe (2)	$ 40.44	$ 25.60	$ 36.32	$ 23.96
Average cost of production per Boe produced (3)				
Rocky Mountain	$ 8.16	$ 8.36	$ 6.88	$ 7.52
Permian/Delaware Basin	9.87	7.63	10.61	12.60
Composite	8.87	7.99	8.48	9.78

(1) Oil and gas were combined by converting gas to Boe on the basis of 6 Mcf of gas to 1 Bbl of oil.
(2) Before the impact of hedging activities.
(3) Production costs include direct lease operating costs but exclude ad valorem taxes and production taxes.

***Availability of Capital*.** As described more fully under "Liquidity and Capital Resources" below, our sources of capital are cash flow from operating activities, proceeds from the sale of properties, monetizing of derivative instruments, and if an appropriate opportunity presents itself, the sale of debt or equity securities, although we may not be able to complete any asset sales or financing on terms acceptable to us, if at all. Our credit facilities were amended in June 2020, resulting in no available borrowing base under our First Lien Credit Facility. Additionally, any excess cash, as defined in the First Lien Credit Facility, is required to be applied to the outstanding balance on a monthly basis, and the borrowing base will be reduced to the new outstanding balance. As a result, with the exception of $3.0 million of funds available for working capital purposes, we have no availability to borrow funds, and except in connection with asset sales or other transaction approved by our lenders, no access to capital in excess of the $3.0 million monthly working capital allowance.

***Borrowings and Interest*.** At September 30, 2021, we had a total of $81.7 million outstanding under our First Lien Credit Facility, $137.1 million under our Second Lien Credit facility, including a $10.0 million exit fee, and total indebtedness of $221.4 million (including the current portion). Additionally, we have an obligation of approximately $9.1 million related to terminated hedging agreements. If interest expense increases as a result of higher interest rates or increased borrowings, more cash flow from operations would be used to meet debt service requirements. As noted above, under the terms of the amended Second Lien Credit Facility, interest under the 2^{nd} Lien Notes is now paid-in-kind by the allocation of additional shares of common stock to our Second Lien Credit Facility lender. We are in default on both of our credit facilities, see Note 10 "Events of Default" for further explanation.

Exploration and Development Activity. If our defaults under existing borrowings can be resolved by repayment or other settlement, then we believe we could access capital to resume development of our assets. We believe that our high quality asset base, high degree of operational control and inventory of drilling projects position us for future growth. At December 31, 2020, we operated properties accounting for virtually all of our PV-10, giving us substantial control over the timing and incurrence of operating and capital expenditures. We have identified numerous additional drilling locations on our existing leaseholds, the successful development of which we believe could significantly increase our production and proved reserves. However, the amendments to our First Lien Credit Facility and Second Lien Credit facility place severe restrictions on our capital expenditures and we have very little planned activity for 2021.

Our future oil and gas production, and therefore our success, is highly dependent upon our ability to find, acquire and develop additional reserves that are profitable to produce. The rate of production from our oil and gas properties and our proved reserves will decline as our reserves are produced unless we acquire additional properties containing proved reserves, conduct successful development and exploration activities or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves. We cannot assure you that we will have any significant exploration and development activities in the near term or that they will result in increases in our proved reserves. If our proved reserves decline in the future, our production may also decline and, consequently, our cash flow from operations will decline. If cash flow declines and we have no access to additional capital, we will be unable to acquire or develop additional reserves or develop our existing undeveloped reserves, in which case our results of operations and financial condition will be adversely affected. Additionally, due to uncertainty regarding our ability to remain a "going concern" and our lack of liquidity, all of our proved undeveloped reserves have been removed from our books.

Results of Operations

Selected Operating Data. The following table sets forth operating data from continuing operations for the periods presented.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Operating revenue (1):				
Oil sales	$ 15,506	$ 12,466	$ 45,199	$ 29,971
Gas sales	2,415	75	5,344	183
NGL sales	2,933	52	5,416	152
Other	11	2	19	8
Total operating revenues	$ 20,865	$ 12,595	$ 55,978	$ 30,314
Operating income (loss)	$ 8,829	$ (56,661)	$ 19,728	$ (147,916)
Oil sales (MBbls)	230	347	743	813
Gas sales (MMcf)	892	454	2,595	1,404
NGL sales (MBbls)	137	69	365	218
Oil equivalents (MBoe)	516	492	1,541	1,265
Average oil sales price (per Bbl)(1)	$ 67.44	$ 35.92	$ 60.82	$ 36.88
Average gas sales price (per Mcf)(1)	$ 2.71	$ 0.17	$ 2.06	$ 0.13
Average NGL sales price (per Bbl)	$ 21.39	$ 0.76	$ 14.83	$ 0.70
Average oil equivalent sales price (Boe) (1)	$ 40.44	$ 25.60	$ 36.32	$ 23.96

(1) Revenue and average sales prices are before the impact of hedging activities.

Comparison of Three Months Ended September 30, 2021 to Three Months Ended September 30, 2020

Operating Revenue. During the three months ended September 30, 2021, operating revenue increased to $20.9 million from $12.6 million for the same period of 2020. The increase in revenue was primarily due to higher commodity prices. Higher realized prices for all products added $12.3 million.to operating revenue for the three months ended September 30, 2021. Lower oil sales volumes negatively impacted revenue by $4.2 million, partially offset by higher gas and NGL sales volumes. Higher sales volumes for gas and NGL added $0.1 million to revenue during the three months ended September 30, 2021 compared to the same period of 2020.

Oil sales volumes decreased to 230 MBbl during the three months ended September 30, 2021 from 347 MBbl for the same period of 2020. The decrease in oil sales volume was primarily due to natural field declines and not bringing any new production on line in 2021. Gas sales volumes increased to 892 MMcf for the three months ended September 30, 2021 from 454 MMcf for the same period of 2020. The increase in gas volumes was the result of bringing deep gas wells back on production that had been shut in since 2019 due to low gas prices.

Lease Operating Expenses (“LOE”). LOE for the three months ended September 30, 2021 increased to $4.6 million from $3.9 million for the same period of 2020. The increase in LOE was primarily due to additional field expense associated with bringing shut in wells back on production as well as an overall increase in the cost of services. We had cost savings as a result of reducing our work force in North Dakota in May 2020 and eliminated substantially all field overtime. LOE per Boe for the three months ended September 30, 2021 was $8.94 compared to $8.00 for the same period of 2020. The increase per Boe was due primarily to lower sales volumes, offset by higher total costs for the three months ended September 30, 2021 compared to the same period of 2020.

Production and Ad Valorem Taxes. Production and ad valorem taxes for the three months ended September 30, 2021 increased to $1.6 million from $1.5 million for the same period of 2020. Production and ad valorem taxes for the three months ended September 30, 2021 were 7% of total oil, gas and NGL sales compared to 12% for the same period of 2020. The higher percentage for 2020 was primarily due to Ad Valorem taxes that do not vary with production volumes.

General and Administrative ("G&A") Expense. G&A expenses, excluding stock-based compensation, decreased to $1.7 million for the three months ended September 30, 2021 compared to $1.8 million in the same period of 2020. G&A per Boe, excluding stock-based compensation, was $3.24 for the quarter ended September 30, 2021 compared to $3.56 for the same period of 2020. The decrease in G&A per Boe, excluding stock based compensation, was primarily due to lower cost and higher sales volumes for the three months ended September 30, 2021 compared to the same period of 2020.

Stock-Based Compensation. Options granted to employees and directors are valued at the date of grant and expense is recognized over the options' vesting period. In addition to options, restricted shares of our common stock have been granted and are valued at the date of grant and expense is recognized over their vesting period. For the three months ended September 30, 2021, and September 30, 2020 stock-based compensation expense was $0.3 million. The majority of our stock based compensation has been fully amortized and no new grants were issued during the three month period ended September 30, 2021.

Depreciation, Depletion and Amortization ("DD&A") Expense. DD&A expense, including accretion of future site restoration, for the three months ended September 30, 2021 decreased to $3.8 million from $6.9 million for the same period of 2020. The decrease was primarily due to higher production volumes offset by a lower full cost pool as a result of the impairments recorded in 2020 as well as lower future development cost included in the September 30, 2021 internal reserve report given the removal of proved undeveloped reserves. Proved undeveloped reserves were removed due to the uncertainty of the Company's ability to be a "going concern" and the lack of available liquidity to develop the reserves. DD&A expense per Boe for the three months ended September 30, 2021 was $7.39 compared to $14.06 in the same period of 2020. The decrease in DD&A expense per Boe was primarily due to a lower full cost pool as the result of the impairment incurred in 2020.

Ceiling Limitation Write-Down. We record the carrying value of our oil and gas properties using the full cost method of accounting for oil and gas properties. Under this method, we capitalize the cost to acquire, explore for and develop oil and gas properties. Under the full cost accounting rules, the net capitalized cost of oil and gas properties less related deferred taxes, are limited by country, to the lower of the unamortized cost or the cost ceiling, defined as the sum of the present value of estimated unescalated future revenues from proved reserves, discounted at 10%, plus the cost of properties not being amortized, if any, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any, less related income taxes. If the net capitalized cost of oil and gas properties exceeds the ceiling limit, we are subject to a ceiling limitation write-down to the extent of such excess. A ceiling limitation write-down is a charge to earnings which does not impact cash flow from operating activities. However, such write-downs do impact the amount of our stockholders' equity and reported earnings. As of September 30, 2021, our net capitalized costs of oil and gas properties did not exceed the cost ceiling of our estimated proved reserves. As of September 30, 2020, our net capitalized costs of oil and gas properties exceeded the cost ceiling of our estimated proved reserves ,resulting in the recognition of an impairment of $54.6 million for the three months ended September 30, 2020.

The risk that we will be required to write-down the carrying value of our oil and gas assets increases when oil and gas prices are depressed or volatile. In addition, write-downs may occur if we have substantial downward revisions in our estimated proved reserves. We cannot assure you that we will not experience additional write-downs in the future.

Interest Expense. Interest expense for the three months ended September 30, 2021 increased to $8.1 million compared to $5.7 million for the same period of 2020. The increase in interest expense in 2021 was due to higher levels of debt and higher interest rates than during the three months ended September 30, 2021 compared to the same period of 2020. The increase in debt levels was primarily due to interest paid in kind on our Second Lien Credit Facility. For the three months ended September 30, 2021, the interest rate on our First Lien Credit Facility averaged 8.8% compared to 4.7% for the same period of 2020. The increase in the average rate on the First Lien Credit Facility was the result of a default interest rate of 8.75% beginning April 22, 2021. The interest rate on our Second Lien Credit Facility averaged 15.8% for the three months ended September 30, 2021 and 2020. We anticipate higher interest rates and increased interest expense in the future as a result of the amendments to our credit facilities. For the three months ended September 30, 2021, approximately $5.0 million in interest expense on our Second Lien Credit Facility was paid in kind.

Loss (Gain) on Derivative Contracts. Derivative gains or losses are determined by actual derivative settlements during the period and on the periodic mark to market valuation of derivative contracts in place at period end. We have elected not to apply hedge accounting to our derivative contracts; therefore, fluctuations in the market value of the derivative contracts are recognized in earnings during the current period. Our derivative contracts consisted of NYMEX-based fixed price swaps and basis differential swaps as of September 30, 2021 and September 30, 2020. The net estimated value of our commodity derivative contracts was a net liability of approximately $2.0 million as of September 30, 2021. When our derivative contract prices are higher than prevailing market prices, we incur gains and, conversely, when our derivative contract prices are lower than prevailing market prices, we incur losses. For the three months ended September 30, 2021, we recognized a loss on our commodity derivative contracts of $0.3 million. For the three months ended September 30, 2020, we recognized a loss on our commodity derivative contracts of $6.6 million.

Income Tax Expense. For the three months ended September 30, 2021 and September 30, 2020 there was no income tax expense recognized due to our NOL carryforwards. The Coronavirus Aid, Relief, and Economic Security Act (the "CARES Act"), that was enacted March 27, 2020, includes income tax provisions that allow net operating losses ("NOLs") to be carried back, allows interest expense to be deducted up to a higher percentage of adjusted taxable income, and modifies tax depreciation of qualified improvement property, among other provisions. These provisions did not have a material impact on the Company.

Comparison of Nine Months Ended September 30, 2021 to Nine Months Ended September 30, 2020

Operating Revenue. During the nine months ended September 30, 2021, operating revenue increased to $56.0 million from $30.3 million for the same period of 2020. The increase in revenue was primarily due to higher commodity prices as well as higher sales volumes during the nine months ended September 30, 2021 compared to the same period of 2020. Higher realized commodity prices for all products contributed $23.6 million in operating revenue, and higher sales volumes for gas and NGL added $4.6 million to operating revenue offset by lower oil sales volumes. Lower oil sales volumes had a negative impact on revenue of $2.6 for the nine months ended September 30, 2021.

Oil sales volumes decreased to 743 MBbl during the nine months ended September 30, 2021, from 813 MBbl for the same period of 2020. Oil volumes were lower primarily due to field declines and no new production being brought on line in 2021. Overall production on a BOE basis was higher in 2021, as a result of bringing wells back on production that were shut in during most of the second quarter of 2020 as a result of the COVID-19 virus and other geopolitical issues affecting the supply and demand for oil and natural gas, and accordingly the prices we received. We made the decision to begin shutting in wells in mid-March 2020. The majority of our oil production was shut in from mid-March through mid-June, 2020 when prices had recovered somewhat. We began bringing wells back on production in mid-June, and had a significant amount of our oil production back on line in July 2020. The increase in gas production was primarily due to shut in wells, as discussed above. Additionally, we have brought a number of dry gas wells in west Texas back on production that had been shut in since approximately April 2019 due to negative gas prices.

Lease Operating Expenses ("LOE"). LOE for the nine months ended September 30, 2021 increased to $13.1 million from $12.3 million for the same period of 2020. The increase was primarily due to expenses related to having wells back on production that were shut in, as discussed above, as well as higher cost of services in 2021 compared to 2020. LOE per Boe for the nine months ended September 30, 2021 was $8.48 compared to $9.71 for the same period of 2020. The decrease per Boe was due primarily to higher sales volumes, partially offset by higher total costs for the nine months ended September 30, 2021, compared to the same period of 2020.

Production and Ad Valorem Taxes. Production and ad valorem taxes for the nine months ended September 30, 2021 increased to $4.6 million from $3.6 million for the same period of 2020. Production and ad valorem taxes for the nine months ended September 30, 2021 were.8% of total oil, gas and NGL sales compared to 12% for the same period of 2020. The higher percentage of revenue in 2020 was due to ad valorem taxes that do not fluctuate with production volumes. the decrease for the nine months ended September 30, 2021 was primarily due to higher commodity prices compared to the same period in 2020 and increased production in Texas which has a lower tax rate..

General and Administrative ("G&A") Expense. G&A expenses, excluding stock-based compensation, was essentially flat at approximately $5.5 million for the nine months ended September 30, 2021 and 2020. G&A expense per Boe, excluding stock-based compensation, was $3.55 for the quarter ended September 30, 2021 compared to $4.39 for the same period of 2020. The decrease per Boe was primarily due to higher sales volumes.

Stock-Based Compensation. Options granted to employees and directors are valued at the date of grant and expense is recognized over the options' vesting period. In addition to options, restricted shares of our common stock have been granted and are valued at the date of grant and expense is recognized over their vesting period. For the nine months ended September 30, 2021, stock-based compensation expense was $0.8 million compared to $0.9 million for the same period of 2020. The decrease was primarily due to the cancellation, forfeiture of restricted stock and options. Substantially all expense related to stock options, restricted stock and performance based shares has been fully amortized with no new grants having been issued during the nine months ended September 30, 2021.

Depreciation, Depletion and Amortization ("DD&A") Expense. DD&A expense, excluding accretion of future site development, for the nine months ended September 30, 2021 decreased to $11.7 million from $18.7 million for the same period of 2020. The decrease was primarily due to lower future development cost included in the September 30, 2021 internal reserve report. DD&A expense per Boe for the nine months ended September 30, 2021 was $7.59 compared to $14.82 in the same period of 2020. The decrease in DD&A expense per Boe was primarily due to a lower full cost pool as the result of the impairment incurred during 2020.

Ceiling Limitation Write-Down. We record the carrying value of our oil and gas properties using the full cost method of accounting for oil and gas properties. Under this method, we capitalize the cost to acquire, explore for, and develop oil and gas properties. Under the full cost accounting rules, the net capitalized cost of oil and gas properties less related deferred taxes, are limited by country, to the lower of the unamortized cost or the cost ceiling, defined as the sum of the present value of estimated unescalated future revenues from proved reserves, discounted at 10%, plus the cost of properties not being amortized, if any, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any, less related income taxes. If the net capitalized cost of oil and gas properties exceeds the ceiling limit, we are subject to a ceiling limitation write-down to the extent of such excess. A ceiling limitation write-down is a charge to earnings which does not impact cash flow from operating activities. However, such write-downs do impact the amount of our stockholders' equity and reported earnings. As of September 30, 2021, our net capitalized costs of oil and gas properties did not exceed the cost ceiling of our estimated proved reserves. As of September 30, 2020, our net capitalized costs of oil and gas properties exceeded the cost ceiling of our estimated proved reserves, resulting in the recognition of an impairment of $136.1 million for the nine months ended September 30, 2020.

The risk that we will be required to write-down the carrying value of our oil and gas assets increases when oil and gas prices are depressed or volatile. In addition, write-downs may occur if we have substantial downward revisions in our estimated proved reserves. We cannot assure you that we will not experience additional write-downs in the future. The volatility in commodity prices due to COVID-19 and geopolitical issues affecting supply and demand, may result in our proved reserves being revised downward, requiring further write-down of the carrying value of our oil and gas properties during the remainder of 2021.

Interest Expense. Interest expense for the nine months ended September 30, 2021 increased to $21.7 million compared to $15.5 million for the same period of 2020. The increase in interest expense in 2021 was due to higher levels of debt during the nine months ended September 30, 2021, compared to the same period in 2020, as well as higher overall interest rates in 2021 compared to 2020. For the nine months ended September 30, 2021, the interest rate on our First Lien Credit Facility averaged 5.8% compared to 4.3% for the same period of 2020. For the nine months ended September 30, 2021, and September 30, 2020 the interest rate on our Second Lien Credit Facility averaged 15.8%, We anticipate higher interest rates and increased interest expense in the future as a result of the amendments to our credit facilities. For the nine months ended September 30, 2021, approximately $14.4 million of the interest paid on the Second Lien Credit Facility was paid in kind.

Loss (Gain) on Derivative Contracts. Derivative gains or losses are determined by actual derivative settlements during the period and on the periodic mark to market valuation of derivative contracts in place at period end. We have elected not to apply hedge accounting to our derivative contracts; therefore, fluctuations in the market value of the derivative contracts are recognized in earnings during the current period. Our derivative contracts consisted of NYMEX-based fixed price swaps and basis differential swaps as of September 30, 2021, and September 30, 2020. The net estimated value of our commodity derivative contracts was a liability of approximately $2.0 million as of September 30, 2021. When our derivative contract prices are higher than prevailing market prices, we incur gains and, conversely, when our derivative contract prices are lower than prevailing market prices, we incur losses. For the nine months ended September 30, 2021, we recognized a loss on our commodity derivative contracts of $18.7 million including a loss of $7.1 million as a result of the termination of our derivative contracts in April 2021. For the nine months ended September 30, 2020, we recognized a gain on our commodity derivative contracts of $53.2 million.

Income Tax Expense. For the nine months ended September 30, 2021 and September 30, 2020, there was no income tax expense recognized due to our NOL carryforwards. The CARES Act, that was enacted March 27, 2020 includes income tax provisions that allow net operating losses (NOLs) to be carried back, allows interest expense to be deducted up to a higher percentage of adjusted taxable income, and modifies tax depreciation of qualified improvement property, among other provisions. These provisions did not have a material impact on the Company.

Liquidity and Capital Resources

General. The oil and gas industry is a highly capital intensive and cyclical business. Our capital requirements are driven principally by our obligations to service debt and to fund the following:

- the development and exploration of existing properties, including drilling and completion costs of wells;
- acquisition of interests in additional oil and gas properties; and
- production and transportation facilities.

The amount of capital expenditures we are able to make has a direct impact on our ability to increase cash flow from operations and, thereby, will directly affect our ability to service our debt obligations and to grow the business through the development of existing properties and the acquisition of new properties. Due to the drastic decrease in oil prices that began in early March 2020 as a result of the OPEC price war and the COVID-19 pandemic, we suspended capital expenditures for 2020 and 2021. Additionally, our amended credit facilities limit capital expenditures to an aggregate of $3.0 million for the trailing four quarters.

Our principal sources of capital are cash flows from operations, proceeds from the sale of properties, and if an opportunity presents itself, the sale of debt or equity securities, although we may not be able to sell properties or complete any financings on terms acceptable to us, if at all. We believe that our cash flow from these sources going forward, will be adequate to fund our operations. In June 2020, our First Lien Credit Facility was amended and has no further availability. Additionally, any excess cash, as defined in the First Lien Credit Facility, will be applied to the outstanding balance on a monthly basis, and the borrowing base will be reduced to the new outstanding balance.

Working Capital (Deficit). At September 30, 2021, our current liabilities of $237.0 million exceeded our current assets $24.9 million, resulting in a working capital deficit of $212.1 million. This compares to a working capital deficit of $195.3 million at December 31, 2020. Current assets as of September 30, 2021 primarily consisted of cash of $9.1 million, accounts receivable of $14.8 million and other current assets of $1.0 million. Current liabilities at September 30, 2021 primarily consisted of trade payables of $2.1 million, revenues due third parties of $12.8 million, current maturities of long-term debt of $209.4 million, the current portion of our derivative liability of $2.0 million, accrued interest of $0.5 million, hedge liability resulting from termination of derivative contracts of $9.2 million and other accrued expenses of $0.9 million.

Capital Expenditures. Capital expenditures for the nine months ended September 30, 2021 and 2020 were $0.9 million and $6.6 million, respectively.

The table below sets forth the components of these capital expenditures:

	Nine Months Ended September 30,	
	2021	2020
	(In thousands)	
Expenditure category:		
Exploration/Development	$ 850	$ 6,410
Facilities and other	6	158
Total	$ 856	$ 6,568

During the nine months ended September 30, 2021 and 2020, our capital expenditures were primarily on our existing properties. Cash basis capital expenditures for the nine months ended September 30, 2021 of $856,000 includes $28,000 for a decrease in capital expenditures in accounts payable, and a decrease in future site restoration of $2.7 million, resulting in net accrual basis capital expenditures of ($1.9) million. As previously described, our amended credit facilities limit capital expenditures to $3.0 million for any four consecutive quarters beginning with the quarter ended June 30, 2020. Based on our capital expenditure limits, the Company will not be able to offset oil and gas production decreases caused by natural field declines.

Sources of Capital. The net funds provided by and/or used in each of the operating, investing and financing activities are summarized in the following table and discussed in further detail below:

	Nine Months Ended September 30,	
	2021	2020
	(In thousands)	
Net cash provided by operating activities	$ 19,876	$ 10,734
Net cash used in investing activities	(483)	(13,187)
Net cash (used in) provided by financing activities	(13,117)	3,036
Total	$ 6,276	$ 583

Operating activities for the nine months ended September 30, 2021 provided $19.9 million in cash compared to providing $10.7 million in the same period of 2020. Losses on derivatives, non-cash interest expense, non-cash termination of hedge liability, and changes in operating assets and liabilities accounted for most of these funds. Investing activities used $483,000 during the nine months ended September 30, 2021, primarily on our existing properties. Investing activities also included a reduction in future site restoration of related to assets sold of $2.7 million and a reduction in accounts payable related to capital expenditures of $0.03 million. Investing activities used $13.2 million during the nine months ended September 30, 2020, primarily for the development of our existing properties. Financing activities used $13.1 million for the nine months ended September 30, 2021 compared to providing $3.0 million for the same period of 2020. Funds used during the three months ended September 30, 2021 were payments on long term debt. Funds provided during the nine months ended September 30, 2020 were primarily net proceeds from borrowings under our credit facility.

Future Capital Resources.

Our principal sources of capital going forward, are cash flows from operations, proceeds from the sale of properties and if an opportunity presents itself, the sale of debt or equity securities, although we may not be able to complete financing on terms acceptable to us, if at all.

Cash from operating activities is dependent upon commodity prices and production volumes. A decrease in commodity prices from current levels would likely reduce our cash flows from operations. This could cause us to alter our business plans, including reducing our exploration and development plans. Unless we otherwise expand and develop reserves, our production volumes may decline as reserves are produced. In the future we may continue to sell producing properties, which could further reduce our production volumes. To offset the loss in production volumes resulting from natural field declines and sales of producing properties, we must conduct successful exploration and development activities, acquire additional producing properties or identify and develop additional behind-pipe zones or secondary recovery reserves. We believe our numerous drilling opportunities will allow us to increase our production volumes; however, our drilling activities are subject to numerous risks, including the risk that no commercially productive oil and gas reservoirs will be found. If our proved reserves decline in the future, our production will also decline and, consequently, our cash flows from operations will decline.

Contractual Obligations. We are committed to making cash payments in the future on the following types of agreements:

- Long-term debt, and
- Operating leases.

Below is a schedule of the future payments that we are obligated to make based on agreements in place as of September 30, 2021:

	Payments due in twelve month periods ending:				
Contractual Obligations	Total	September 30, 2022	September 30, 2023-2024	September 30, 2025-2026	Thereafter
Long-term debt (1)	$ 230,558	$ 228,274	$ 2,284	$ -	$ -
Interest on long-term debt (2)	5,177	5,091	86		-
Paid in kind interest on long-term debt (3)	22,520	20,018	2,502	-	-
Lease obligations	230	49	79	8	94
Total	$ 258,485	$ 253,432	$ 4,951	$ 8	$ 94

(1) These amounts represent the balances outstanding under our credit facilities and the real estate lien note. These payments assume that we will not borrow additional funds.

(2) Interest expense assumes the balances of our First Lien Credit Facility and Real Estate Lien Note at the end of the period and current effective interest rates.

(3) Represents interest expense paid in kind on our Second Lien Credit Facility, accrued interest is added to the outstanding balance and is payable at maturity.

We maintain a reserve for costs associated with future site restoration related to the retirement of tangible long-lived assets. At September 30, 2021, our reserve for these obligations totaled $4.7 million for which no contractual commitments exist. For additional information relating to this obligation, see Note 1 of the Notes to Condensed Consolidated Financial Statements.

Off-Balance Sheet Arrangements. At September 30, 2021, we had no existing off-balance sheet arrangements, as defined under SEC regulations, that have, or are reasonably likely to have a current or future material effect on our financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that are material to investors.

Contingencies. From time to time, we are involved in litigation relating to claims arising out of our operations in the normal course of business. At September 30, 2021, we were not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on us.

Paycheck Protection Program Loan

On May 4, 2020, the Company entered into an unsecured loan with the U.S. Small Business Administration (the "SBA") in the amount of $1.4 million under the Paycheck Protection Program (the "PPP Loan") with an interest rate of 1.0% and maturity date two years from the effective date of the PPP Loan. The Paycheck Protection Program was established under the CARES Act and is administered by the SBA. Payments are required to be made in seventeen monthly installments of principal and interest, with the first payment being due on the date that is seven months after the date of the PPP Loan. Under the CARES Act, as amended by the Paycheck Protection Program Flexibility Act of 2020, the PPP Loan is eligible for forgiveness for the portion of the PPP Loan proceeds used for payroll costs and other designated operating expenses, provided at least 60% of the PPP Loan's proceeds are used for payroll costs and the Company meets all necessary criteria for forgiveness. Receipt of these funds requires the Company to, in good faith, certify that the PPP Loan was necessary to support ongoing operations of the Company during the economic uncertainty created by the COVID-19 pandemic. This certification further requires the Company to take into account current business activity and the ability to access other sources of liquidity sufficient to support ongoing operations in a manner that is not significantly detrimental to the business. This loan was forgiven in January 2021. On March 18, 2021, the Company entered into an additional unsecured loan with the SBA in the amount of $1.3 million. The terms of this loan are the same as the May 4, 2020 loan discussed above. The SBA provides no assurance that the Company will obtain forgiveness of the PPP Loan in whole or in part.

Long-Term Indebtedness.

The following sections regarding the First Lien Credit Facility and Second Lien Credit Facility are qualified in their entirety by the disclosure contained in Note 1 Basis of Presentation, "Going Concern" . Due to certain of covenant violations under our credit facilities as of December 31, 2020, and the potential for future violations, all of the debt related to our credit facilities has been classified as current liabilities.

Long-term debt consisted of the following (in thousands):

	September 30, 2021	December 31, 2020
First Lien Credit Facility	$ 81,689	$ 95,000
Second Lien Credit Facility	127,101	112,695
Exit fee - Second Lien Credit Facility	10,000	10,000
Real estate lien note	2,590	2,810
	221,380	220,505
Less current maturities	(209,434)	(202,751)
	11,946	17,754
Deferred financing fees and debt issuance cost, net	(9,662)	(15,239)
Total long-term debt, net of deferred financing fees and debt issuance costs	$ 2,284	$ 2,515

The following sections regarding the First Lien Credit Facility and Second Lien Credit Facility are qualified in their entirety by the disclosure contained in Note 1 Basis of Presentation, "going concern", and Strategic Alternatives disclosures set forth on page 40 of this quarterly report, which are expressly incorporated in the sections below. Due to certain covenant violations as of December 31, 2020 and September 30, 2021, all of the debt related to our credit facilities has been classified as current liabilities.

First Lien Credit Facility

The Company has a senior secured First Lien Credit Facility with Société Générale, as administrative agent and issuing lender, and certain other lenders. As of September 30, 2021, $81.7 million was outstanding under the First Lien Credit Facility.

Outstanding amounts under the First Lien Credit Facility accrue interest at a rate per annum equal to (i) for borrowings that we elect to accrue interest at the reference rate at the greater of (x) the reference rate announced from time to time by Société Générale, (y) the federal funds rate plus 0.5%, and (z) daily one-month LIBOR plus, in each case, 1.5%-2.5%, depending on the utilization of the borrowing base, and (ii) for borrowings that we elect to accrue interest at the Eurodollar rate, LIBOR plus 2.5%-3.5% depending on the utilization of the borrowing base. However, at any time an event of default exists, the default rate is 3.0% plus the amounts set forth above. At September 30, 2021, the interest rate on the First Lien Credit Facility was approximately 8.75%.

Subject to earlier termination rights and events of default, the stated maturity date of the First Lien Credit Facility is May 16, 2022. Interest is payable quarterly on reference rate advances and not less than quarterly on LIBOR advances. The Company is permitted to terminate the First Lien Credit Facility and is able, from time to time, to permanently reduce the lenders' aggregate commitment under the First Lien Credit Facility in compliance with certain notice and dollar increment requirements.

Each of the Company's subsidiaries has guaranteed our obligations under the First Lien Credit Facility on a senior secured basis. Obligations under the First Lien Credit Facility are secured by a first priority perfected security interest, subject to certain permitted encumbrances, in all of the Company and its subsidiary guarantors' material property and assets. As of September 30, 2021, the collateral is required to include properties comprising at least 90% of the PV-9 of the Company's proven reserves and 95% of the PV-9 of the Company's PDP reserves.

Under the First Lien Credit Facility, the Company is subject to customary covenants, including financial covenants and reporting covenants. The latest amendment to the First Lien Credit Facility (the "1L Amendment") modified certain provisions of the First Lien Credit Facility, including (i) the addition of monthly mandatory prepayments from excess cash (defined as available cash minus certain cash set-asides and a $3.0 million working capital reserve) with corresponding reductions to the borrowing base; (ii) the elimination of scheduled redeterminations (which were previously made every six months) and interim redeterminations (which were previously made at the request of the lenders no more than once in the six month period between scheduled redeterminations) of the borrowing base; (iii) the replacement of total debt leverage ratio and minimum asset ratio covenants with a first lien debt leverage ratio covenant (comparing the outstanding debt of the First Lien Credit Facility to the consolidated EBITDAX of the Company and requiring that the ratio not exceed 2.75 to 1.00 as of the last day of each fiscal quarter) and a minimum first lien asset coverage ratio covenant (comparing the sum of, without duplication, (A) the PV-15 of producing and developed proven reserves of the Company, (B) the PV-9 of the Company's hydrocarbon hedging agreements and (C) the PV-15 of proved reserves of the Company classified as "drilled uncompleted" (up to 20% of the sum of (A), (B) and (C)) to the outstanding debt of the First Lien Credit Facility and requiring that the ratio exceed 1.15 to 1.00 as of the last day of each fiscal quarter ending on or before December 31, 2020, and 1.25 to 1.00 for fiscal quarters ending thereafter); (iv) the elimination of current ratio and interest coverage ratio covenants; (v) additional restrictions on (A) capital expenditures (limiting capital expenditures to $3.0 million in any four fiscal quarter period (commencing with the four fiscal quarter period ended June 30, 2020 and calculated on an annualized basis for the 1, 2 and 3 quarter periods ended on June 30, 2020, September 30, 2020 and December 31, 2020, respectively, subject to certain exceptions, including capital expenditures financed with the proceeds of newly permitted, structurally subordinated debt and capital expenditures made when (1) the first lien asset coverage ratio is at least 1.60 to 1.00, (2) the Company is in compliance with the first lien leverage ratio, (3) the amounts outstanding under the First Lien Credit Facility are less than $50.0 million, (4) no default exists under the First Lien Credit Facility, and (5) and all representations and warranties in the First Lien Credit Facility and the related credit documents are true and correct in all material respects), (B) outstanding accounts payable (limiting all outstanding and undisputed accounts payable to $7.5 million, undisputed accounts payable outstanding for more than 60 days to $2.0 million and undisputed accounts payable outstanding for more than 90 days to $1.0 million, and (C) general and administrative expenses (limiting cash general and administrative expenses the Company may make or become legally obligated to make in any four fiscal quarter period to $9.0 million for the four fiscal quarter period ended June 30, 2020, $8.25 million for the four fiscal quarter period ended September 30, 2020, $6.9 million for the four fiscal quarter period ended December 31, 2020, and $6.5 million for the fiscal quarter from March 31, 2021 through December 31, 2021 and $5.0 million thereafter; in all cases, general and administrative expense excludes up to $1.0 million in certain legal and professional fees; and (vi) permission for up to an additional $25.0 million in structurally subordinated debt to finance capital expenditures. Under the 1L Amendment, the borrowing base was adjusted from $135.0 million to $102.0 million.

At September 30, 2021, the Company's borrowing base was $81.7 million, the amount outstanding on the First Lien Credit Facility, and thus the Company had no further borrowings available. The borrowing is reduced by any mandatory prepayments from excess cash flow (in an amount equal to such prepayment) and upon the disposition of the Company's oil and gas properties.

As of September 30, 2021, we were not in compliance with the financial covenants under the First Lien Credit Facility.

The First Lien Credit Facility contains a number of covenants that, among other things, restrict our ability to:

- incur or guarantee additional indebtedness;
- transfer or sell assets;
- create liens on assets;
- pay dividends or make other distributions on capital stock or make other restricted payments;
- engage in transactions with affiliates other than on an "arm's length" basis;
- make any change in the principal nature of our business; and
- permit a change of control.

The First Lien Credit Facility also contains customary events of default, including nonpayment of principal or interest, violations of covenants, cross default and cross acceleration to certain other indebtedness, bankruptcy and material judgments and liabilities.

Events of default have occurred under the First Lien Credit Facility as a result of (i) our failure to timely deliver audited financial statements without a "going concern" or like qualification for the fiscal year ended December 31, 2020, (ii) our inability to comply with the first lien debt to consolidated EBITDAX ratio for the fiscal quarter ended December 31, 2020, (iii) our failure to cause certain deposit accounts to be subject to control agreements in favor of the administrative agent for the First Lien Credit Facility and (iv) certain cross-defaults that have occurred, or may occur, as a result of the events of default under the First Lien Credit Agreement and corresponding cross-defaults under the Second Lien Credit Facility and cross-defaults or similar termination events under our hedging contracts.

Second Lien Credit Facility

On November 13, 2019, we entered into the Term Loan Credit Agreement, with Angelo Gordon Energy Servicer, LLC, as administrative agent, and certain other lenders party thereto, which we refer to as the Second Lien Credit Facility. The Second Lien Credit Facility was amended on June 25, 2020. The Second Lien Credit Facility has a maximum commitment of $100.0 million. As of September 30, 2021, the outstanding balance on the Second Lien Credit Facility was $137.1 million, including an exit fee of $10.0 million.

The stated maturity date of the Second Lien Credit Facility is November 13, 2022. Prior to the latest amendments to the Second Lien Credit Facility, accrued interest was payable quarterly on reference rate loans and at the end of each three-month interest period on Eurodollar loans. We are permitted to prepay the loans in whole or in part, in compliance with certain notice and dollar increment requirements.

Each of our subsidiaries has guaranteed our obligations under the Second Lien Credit Facility. Obligations under the Second Lien Credit Facility are secured by a first priority perfected security interest, subject to certain permitted liens, including those securing the indebtedness under the First Lien Credit Facility to the extent permitted by the Intercreditor Agreement, of even date with the Second Lien Credit Facility, among us, our subsidiaries, Angelo Gordon Energy Servicer, LLC and Société Générale, in all of our subsidiary guarantors' material property and assets. As of September 30, 2020, the collateral is required to include properties comprising at least 90% of the PV-9 of the Company's proven reserves and 95% of the PV-9 of the Company's PDP reserves.

Under the Second Lien Credit Facility, the Company is subject to customary covenants, including financial covenants and reporting covenants. The amendment to the Second Lien Credit Facility dated June 25, 2020 (the "2L Amendment") modified certain provisions of the Second Lien Credit Facility, including (i) a requirement that, while the obligations under the First Lien Credit Facility are outstanding, scheduled payments of accrued interest under the Second Lien Credit Facility will be paid in the form of capitalized interest; (ii) an increase in the interest rate by 200bps for interest payable in cash and 500bps for interest payable in kind; (iii) modification of the minimum asset ratio covenant to be the sum of, without duplication, (A) the PV-15 of producing and developed proven reserves of the Company, (B) the PV-9 of the Company's hydrocarbon hedging agreements and (C) the PV-15 of proved reserves of the Company classified as "drilled uncompleted" (up to 20% of the sum of (A), (B) and (C)) to the total outstanding debt of the Company and requiring that the ratio not exceed 1.45 to 1.00 as of the last day of each fiscal quarter ending between September 30, 2021 to December 31, 2021, and 1.55 to 1.00 for fiscal quarters ending thereafter); (iv) modification of the total leverage ratio covenant to set the first test date which occurred on September 30, 2021; (v) modification of the current ratio to eliminate the exclusion of certain valuation accounts associated with hedging agreements from current assets and from current liabilities, (vi) additional restrictions on (A) capital expenditures (limiting capital expenditures to those expenditures set forth in a plan of development approved by Angelo Gordon Energy Servicer, LLC, subject to certain exceptions, including capital expenditures financed with the proceeds of newly permitted, structurally subordinated debt), (B) outstanding accounts payable (limiting all outstanding and undisputed accounts payable to $7.5 million, undisputed accounts payable outstanding for more than 60 days to $2.0 million and undisputed accounts payable outstanding for more than 90 days to $1.0 million and (C) general and administrative expenses (limiting cash general and administrative expenses the Company may make or become legally obligated to make in any four fiscal quarter period to $9.0 million for the four fiscal quarter period ended June 30, 2020, $8.25 million for the four fiscal quarter period ended September 30, 2020, $6.5 million for fiscal quarter period from March 31, 2021 through December 31, 2021 and $5.0 million thereafter.

As of September 30, 2021, we were not in compliance with the financial covenants under the Second Lien Credit Facility as amended.

The Second Lien Credit Facility contains a number of covenants that, among other things, restrict our ability to:

- incur or guarantee additional indebtedness;
- transfer or sell assets;
- create liens on assets;
- pay dividends or make other distributions on capital stock or make other restricted payments;
- engage in transactions with affiliates other than on an "arm's length" basis;
- make any change in the principal nature of our business; and
- permit a change of control.

The Second Lien Credit Facility also contains customary events of default, including nonpayment of principal or interest, violation of covenants, cross default and cross acceleration to certain other indebtedness, bankruptcy and material judgments and liabilities.

In connection with the amendment to the Second Lien Credit Facility on June 25, 2020, the Company entered into an Exit Fee and Warrant Agreement, subject to NASDAQ approval for the issuance of certain warrants. This agreement was finalized on August 11, 2020 at which time the Company issued a warrant to the lender to purchase a total of 33,445,792 shares of common stock at an exercise price of $0.01 per share. On October 19, 2020, the Company effected a reverse stock split of the Company's authorized, issued and outstanding shares of common stock at a ratio of 1-for-20, thus the warrant was adjusted to provide that the lender may purchase a total of 1,672,290 shares of common stock at an exercise price of $0.20 per share. The warrant is exercisable immediately in whole or in part, at any time on or before five years from the issuance date. The fair value of the warrant and exit fee were recorded as debt issuance costs, presented in the consolidated balance sheets as a deduction from the carrying amount of the note payable, and are being amortized over the loan term. The Exit Fee shall be due and payable in cash on the earliest to occur of maturity of the obligation under the Second Lien Credit Facility or the earlier acceleration or payment in full of the same. The 2L Amendment, including the impact of the Exit Fee and Warrant Agreement finalized on August 11, 2020, resulted in the 2L Amendment meeting the criteria of debt extinguishment under the guidance of *ASC 470: Debt*. Accordingly, all debt issuance cost, including the original discount of the original Second Lien Credit Facility, were charged to debt extinguishment loss in the accompanying Condensed Consolidated Statement of Operation in the amount of $4.1 million.

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Real Estate Lien Note

We have a real estate lien note secured by a first lien deed of trust on the property and improvements which serves as our corporate headquarters. The note was modified on June 20, 2018 to a fixed rate of 4.9% and is payable in monthly installments of $35,672. The maturity date of the note is July 20, 2023. As of September 30, 2021, and December 31, 2020, $2.6 million and $2.8 million, respectively, were outstanding on the note.

Hedging Activities

Our results of operations are significantly affected by fluctuations in commodity prices and we seek to reduce our exposure to price volatility by hedging our production through swaps, options and other commodity derivative instruments. We had entered into commodity swaps on approximately 33% of our estimated oil production from our net proved developed producing reserves (based on reserve estimates at September 30, 2021) from October through December 31, 2021, and nothing thereafter due to the termination of substantially all of our hedging arrangements in April 2021. See Note 10 “Events of Default”.

By removing a portion of price volatility on our future oil and gas production, we believe that we will mitigate, but not eliminate, the potential effects of changing commodity prices on our cash flow from operations. However, when prevailing market prices are higher than our contract prices, we will not realize increased cash flow on the portion of the production that has been hedged. We have sustained, and in the future, will sustain, losses on our derivative contracts when market prices are higher than our contract prices. Conversely, when prevailing market prices are lower than our contract prices, we will sustain gains on our commodity derivative contracts.

If the disparity between our contract prices and market prices continues, we will sustain gains or losses on our derivative contracts. While gains and losses resulting from the periodic mark to market of our open contracts do not impact our cash flow from operations, gains and losses from settlements of our closed contracts do impact our cash flow from operations.

If the prices at which we hedge future production are significantly lower than our existing derivative contracts, our future cash flow from operations would likely be materially lower.

Strategic Alternatives

As noted above, defaults under our First Lien Credit Facility and Second Lien Credit Facility, and constraints imposed by the lenders in the most recent amendments to those facilities, have deprived us of capital resources necessary to continue to develop our assets and generate cash. As a result, we have virtually no excess cash flow or available capital. While we have sought additional forbearances from our lenders, to date no additional relief has been forthcoming. However, increased energy prices have made the climate more favorable for discussions regarding possible negotiated transactions that would reduce or eliminate our existing long-term indebtedness.

The Company has continued its previously announced investigation of strategic alternatives and is in discussions with its creditors in an effort to restructure its balance sheet. Any negotiated transaction with its lenders would likely include a sale of a significant block of assets, the proceeds from which would be applied to reduce debt, the exchange of a significant amount of equity interests in the Company for outstanding indebtedness, and/or other possible negotiated transactions, which in the aggregate would eliminate or substantially reduce the outstanding indebtedness under its First Lien Credit Facility and Second Lien Credit facility and result in significant dilution of existing stockholder interests and reduction or potentially elimination of value for existing stockholders. Any such transaction could involve a proceeding under the U.S. Bankruptcy Code. No assurance can be provided that any such potential transactions can be successfully concluded, in which event the Company’s lenders may commence foreclosure proceedings seeking to liquidate Company assets to repay the outstanding indebtedness. In any such foreclosure proceedings, it is unlikely that stockholders would recover more than a de minimis amount for their stock, and the stock could become worthless.

Item 3. Quantitative and Qualitative Disclosures about Market Risk.

Commodity Price Risk

As an independent oil and gas producer, our revenue, cash flow from operations, other income and profitability, reserve values, access to capital and future rate of growth are substantially dependent upon the prevailing prices of oil and gas. Declines in commodity prices will adversely affect our financial condition, liquidity, ability to obtain financing and operating results. Lower commodity prices may reduce the amount of oil and gas that we can produce economically. Prevailing prices for such commodities are subject to wide fluctuation in response to relatively minor changes in supply and demand and a variety of additional factors beyond our control, such as global, political and economic conditions. Historically, prices received for our oil and gas production have been volatile and unpredictable, and such volatility is expected to continue. Most of our production is sold at market prices. Generally, if the commodity indexes fall, the price that we receive for our production will also decline. Therefore, the amount of revenue that we realize is partially determined by factors beyond our control. Assuming the production levels we attained during the nine months ended September 30, 2021, a 10% decline in oil and gas prices would have reduced our operating revenue, cash flow and net income by approximately $5.6 million. If commodity prices decline from current levels, the impact on operating revenues and cash flow, could be much more significant.

Derivative Instrument Sensitivity

At September 30, 2021, the aggregate fair market value of our commodity derivative contracts was a liability of approximately $2.0 million. The fair market value of our commodity derivative contracts is sensitive to changes in the market price for oil and gas. When our derivative contract prices are higher than prevailing market prices, we incur gains and conversely, when our derivative contract prices are lower than prevailing market prices, we incur losses.

Interest Rate Risk

We are subject to interest rate risk associated with borrowings under our credit facility and our second lien credit facility. As of September 30, 2021, we had $81.7 million of outstanding indebtedness under our First Lien Credit Facility and $127.1 million outstanding under our Second Lien Credit Facility, excluding an exit fee of $10.0 million, each with a variable interest rate. At September 30, 2021, the interest rate on the credit facility was 8.75%. An increase in the interest rate of 1% would increase our interest expense by $0.8 million on an annual basis, based on the outstanding balance at September 30, 2021. At September 30, 2021, the interest rate on the Second Lien Credit Facility was 15.75% based on 3-month LIBOR borrowings. An increase of 1% would increase our interest expense by $1.2 million on an annual basis, based on the outstanding balance at September 30, 2021.

Item 4. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, our Chief Executive Officer and Chief Financial Officer carried out an evaluation of the effectiveness of our "disclosure controls and procedures” (as defined in the Securities Exchange Act of 1934 Rules 13a-15(e)and 15d-15(e)) and concluded that the disclosure controls and procedures were effective.

Changes in Internal Control over Financial Reporting

There were no changes in our internal controls over financial reporting during the three months ended September 30, 2021 covered by this report that could materially affect, or are reasonably likely to materially affect, our financial reporting.

PART II

Item 1. Legal Proceedings.

From time to time, we are involved in litigation relating to claims arising out of its operations in the normal course of business. At September 30, 2021, we were not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse impact on our financial position or results of operations.

Item 1A. Risk Factors.

In addition to the other information set forth in this report, you should carefully consider the factors discussed in Part I, “Item 1A. Risk Factors” in our Annual Report on Form 10-K for the year ended December 31, 2020, which could materially affect our business, financial condition or future results. The risks described in our Annual Report on Form 10-K are not the only risks facing Abraxas. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition and/or operating results.

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

None

Item 3. Defaults Upon Senior Securities.

None

Item 4. Mine Safety Disclosure.

Not applicable

Item 5. Other Information.

None

Item 6. Exhibits.

(a) Exhibits

Exhibit 31.1	Certification - Robert L.G. Watson, CEO
Exhibit 31.2	Certification - Steven P. Harris, CFO
Exhibit 32.1	Certification pursuant to 18 U.S.C. Section 1350 - Robert L.G. Watson, CEO
Exhibit 32.2	Certification pursuant to 18 U.S.C. Section 1350 - Steven P. Harris, CFO
101.INS	Inline XBRL Instance Document (the Instance Document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document)
101.SCH	Inline XBRL Taxonomy Extension Schema Document
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	Inline XBRL Taxonomy Extension Label Linkbase Document
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

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ABRAXAS PETROLEUM CORPORATION

SIGNATURES

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

Date	**November 15, 2021**	**By:** /s/Robert L.G. Watson **ROBERT L.G. WATSON,** **President and** **Principal Executive Officer**
Date	**November 15, 2021**	**By**: /s/Steven P. Harris **STEVEN P. HARRIS** **Vice President and** **Principal Financial Officer**
Date	**November 15, 2021**	**By**: /s/G. William Krog, Jr. **G. WILLIAM KROG, JR.,** **Vice President and** **Principal Accounting Officer**

Exhibit 31.1

CERTIFICATIONS

I, Robert L. G. Watson, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Abraxas Petroleum Corporation.

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

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

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal controls 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 fourth fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.

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

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

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

Date: November 15, 2021
/s/ Robert L.G. Watson
Robert L.G. Watson
Chairman of the Board, President and
Principal Executive Officer

Exhibit 31.2

CERTIFICATIONS

I, Steven P. Harris, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Abraxas Petroleum Corporation.

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

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

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal controls 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 fourth fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.

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

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

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

Date: November 15, 2021
/s/ Steven P. Harris
Steven P. Harris
Vice President and
Principal Financial Officer

Exhibit 32.1

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

In connection with the Quarterly Report of Abraxas Petroleum Corporation (the “Company”) on Form 10-Q for the quarter ended September 30, 2021 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Robert L.G. Watson, Chairman of the Board, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Robert L.G. Watson
Robert L.G. Watson
Chairman of the Board, President and Chief Executive Officer
November 15, 2021

This certification accompanies the Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not, except to the extent required by the Sarbanes-Oxley Act of 2002, be deemed filed by the Company for purposes of §18 of the Securities Exchange Act of 1934, as amended.

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

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

In connection with the Quarterly Report of Abraxas Petroleum Corporation (the “Company”) on Form 10-Q for the quarter ended September 30, 2021 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Steven P. Harris, Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/Steven P. Harris
Steven P. Harris
Vice President and Chief Financial Officer
November 15, 2021

This certification accompanies the Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not, except to the extent required by the Sarbanes-Oxley Act of 2002, be deemed filed by the Company for purposes of §18 of the Securities Exchange Act of 1934, as amended.

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.