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

Form 10-K

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

For the fiscal year ended December 31, 2021

OR

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

For the transition period from to .

Commission File Number: 001-35512

AMPLIFY ENERGY CORP.
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**82-1326219** (I.R.S. Employer Identification No.)
500 Dallas Street, Suite 1700, Houston, TX (Address of principal executive offices)	**77002** (Zip Code)

Registrant's telephone number, including area code: **(832) 219-9001**

Securities registered pursuant to Section 12(g) of the Act: **None**

Securities Registered Pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock	AMPY	NYSE

Indicate by check mark if the registrant is a well–known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☑

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑

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

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

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

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

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

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☐

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

The aggregate market value of voting and non-voting common equity held by non-affiliates of the registrant was approximately $140.4 million on June 30, 2021, based on $4.05 per share, the last reported sales price of the shares on the New York Stock Exchange on such date.

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Section 12, 13, or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yes ☑ No ☐

As of February 28, 2022, the registrant had 38,064,214 outstanding shares of Common Stock, $0.01 par value per share.

Documents Incorporated By Reference**:** Portions of the registrant's definitive proxy statement relating to its 2021 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2021, are incorporated by reference to the extent set forth in Part III, Items 10-14 of this Form 10-K.

AMPLIFY ENERGY CORP.
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GLOSSARY OF OIL AND NATURAL GAS TERMS

3-D seismic: Geophysical data that depict the subsurface strata in three dimensions. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D, or two-dimensional, seismic.

Analogous Reservoir: Analogous reservoirs, as used in resource assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, analogous reservoir refers to a reservoir that shares all of the following characteristics with the reservoir of interest: (i) the same geological formation (but not necessarily in pressure communication with the reservoir of interest); (ii) the same environment of deposition; (iii) similar geologic structure; and (iv) the same drive mechanism.

API Gravity: A system of classifying oil based on its specific gravity, whereby the greater the gravity, the lighter the oil.

Basin: A large depression on the earth's surface in which sediments accumulate.

Bbl: One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

Bbl/d: One Bbl per day.

Bcfe: One billion cubic feet of natural gas equivalent.

Boe: One barrel of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Bbl of oil.

Boe/d: One Boe per day.

BOEM: Bureau of Ocean Energy Management.

BSEE: Bureau of Safety and Environmental Enforcement.

Btu: One British thermal unit, the quantity of heat required to raise the temperature of a one-pound mass of water by one-degree Fahrenheit.

CO_2: Carbon dioxide.

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

Developed Acreage: The number of acres which are allocated or assignable to producing wells or wells capable of production.

Development Project: A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

Development Well: A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Differential: An adjustment to the price of oil or natural gas from an established spot market price to reflect differences in the quality and/or location of oil or natural gas.

Dry Hole or ***Dry Well***: A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production would exceed production expenses and taxes.

Economically Producible: The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. For this determination, the value of the products that generate revenue is determined at the terminal point of oil and natural gas producing activities.

Estimated Ultimate Recovery: Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

Exploitation: A development or other project which may target proven or unproven reserves (such as probable or possible reserves) but which generally has a lower risk than that associated with exploration projects.

Exploratory Well: A well drilled to find and produce oil and natural gas reserves not classified as proved, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir or to extend a known reservoir.

Field: An area consisting of a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

Gross Acres or ***Gross Wells***: The total acres or wells, as the case may be, in which we have a working interest.

ICE: Inter-Continental Exchange.

MBbl: One thousand Bbls.

MBbls/d: One thousand Bbls per day.

MBoe: One thousand barrels of oil equivalent.

MBoe/d: One thousand barrels of oil equivalent per day.

MMBoe: One million barrels of oil equivalent.

Mcf: One thousand cubic feet of natural gas.

MMBtu: One million British thermal units.

MMcf: One million cubic feet of natural gas.

MMcfe: One million cubic feet of natural gas equivalent.

MMcfe/d: One MMcfe per day.

Net Acres or ***Net Wells***: Gross acres or wells, as the case may be, multiplied by our working interest ownership percentage.

Net Production: Production that is owned by us less royalties and production due others.

Net Revenue Interest: A working interest owner's gross working interest in production less the royalty, overriding royalty, production payment and net profits interests.

NGLs: The combination of ethane, propane, butane and natural gasolines that, when removed from natural gas become liquid under various levels of higher pressure and lower temperature.

NYMEX: New York Mercantile Exchange.

NYSE: New York Stock Exchange.

Oil: Oil and condensate.

Operator: The individual or company responsible for the exploration and/or production of an oil or natural gas well or lease.

Plugging and abandonment*:* Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another stratum or to the surface. Regulations of all states require plugging of abandoned wells.

Present value of future net revenues or ***PV-9***: The estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses, discounted to a present value using an annual discount rate of 9% in accordance with the guidelines of the U.S. Securities Exchange Commission (the "SEC").

Present value of future net revenues or ***PV-10***: The estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses, discounted to a present value using an annual discount rate of 10% in accordance with the guidelines of the SEC.

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

Productive Well: A well that produces commercial quantities of hydrocarbons, exclusive of its capacity to produce at a reasonable rate of return.

Proved Developed Reserves: Proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods.

Proved Reserves: Those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible, from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations, prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence the project within a reasonable time. The area of the reservoir considered as proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or natural gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons, as seen in a well penetration, unless geoscience, engineering or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil elevation, and the potential exists for an associated natural gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves that can be produced economically through application of improved recovery techniques (including fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir, or an analogous reservoir or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price used is the average price during the twelve-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved Undeveloped Reserves: Proved oil and natural gas reserves 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. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Realized Price: The cash market price less all expected quality, transportation and demand adjustments.

Recompletion: The completion for production of an existing wellbore in another formation from that which the well has been previously completed.

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

Reserve Life: A measure of the productive life of an oil and natural gas property or a group of properties, expressed in years. Reserve life is calculated by dividing proved reserve volumes at year end by production volumes. In our calculation of reserve life, production volumes are adjusted, if necessary, to reflect property acquisitions and dispositions.

Reserves: Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to market and all permits and financing required to implement the project. Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

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

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

SEC: The U.S. Securities and Exchange Commission

Spacing: The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres (e.g., 40-acre spacing) and is often established by regulatory agencies.

Standardized Measure: The present value of estimated future net revenue to be generated from the production of proved reserves, determined in accordance with the rules, regulations or standards established by the SEC and the Financial Accounting Standards Board (“FASB”) (using prices and costs in effect as of the date of estimation), less future development, production and income tax expenses and discounted at 10% per annum to reflect the timing of future net revenue. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in our oil and natural gas properties. Standardized measure does not give effect to derivative transactions.

Undeveloped Acreage: Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

Wellbore: The hole drilled by the bit that is equipped for oil or natural gas production on a completed well. Also called well or borehole.

Working Interest: An interest in an oil and natural gas lease that gives the owner of the interest the right to drill for and produce oil and natural gas on the leased acreage and generally requires the owner to pay a share of the costs of drilling and production operations.

Workover: Operations on a producing well to restore or increase production.

WTI: West Texas Intermediate.

NAMES OF ENTITIES

As used in this Form 10-K, unless we indicate otherwise:

- “Amplify Energy” “Company,” “we,” “our,” “us,” or like terms refers to Amplify Energy Corp. (f/k/a Midstates Petroleum Company, Inc.) individually and collectively with its subsidiaries, as the context requires;

- “Legacy Amplify” refers to Amplify Energy Holdings LLC (f/k/a Amplify Energy Corp.), the successor reporting company of Memorial Production Partners LP; and

- “OLLC” refers to Amplify Energy Operating LLC, the Company’s wholly owned subsidiary through which it operates its properties.

FORWARD–LOOKING STATEMENTS

This Annual Report on Form 10-K contains forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control, which may include statements about our:

- business strategies;
- ongoing impact of the oil incident that occurred off the coast of Southern California resulting from the Company's pipeline operations (the "Pipeline") at the Beta field (the "Incident");
- acquisition and disposition strategy;
- cash flows and liquidity;
- financial strategy;
- ability to replace the reserves we produce through drilling;
- drilling locations;
- oil and natural gas reserves;
- technology;
- realized oil, natural gas and NGL prices;
- production volumes;
- lease operating expense;
- gathering, processing and transportation;
- general and administrative expense;
- future operating results;
- ability to procure drilling and production equipment;
- ability to procure oil field labor;
- planned capital expenditures and the availability of capital resources to fund capital expenditures;
- ability to access capital markets;
- marketing of oil, natural gas and NGLs;
- acts of God, fires, earthquakes, storms, floods, other adverse weather conditions, war, acts of terrorism, military operations or national emergency;
- the occurrence or threat of epidemic or pandemic diseases, including the coronavirus ("COVID-19") pandemic, or any government response to such occurrence or threat;
- expectations regarding general economic conditions;

- competition in the oil and natural gas industry;
- effectiveness of risk management activities;
- environmental liabilities;
- counterparty credit risk;
- expectations regarding governmental regulation and taxation;
- expectations regarding developments in oil-producing and natural-gas producing countries; and
- plans, objectives, expectations and intentions.

All statements, other than statements of historical fact, included in this report are forward-looking statements. These forward-looking statements may be found in “Item 1. Business,” “Item 1A. Risk Factors,” “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and other items within this Annual Report on Form 10-K. In some cases, you can identify forward-looking statements by terminology such as “may,” “will,” “could,” “should,” “expect,” “plan,” “project,” “intend,” “anticipate,” “believe,” “estimate,” “predict,” “potential,” “pursue,” “target,” “outlook,” “continue,” the negative of such terms or other comparable terminology. These statements address activities, events or developments that we expect or anticipate will or may occur in the future, including things such as projections of results of operations, plans for growth, goals, future capital expenditures, competitive strengths, references to future intentions and other such references. These forward-looking statements involve risks and uncertainties. Important factors that could cause the Company’s actual results or financial condition to differ materially from those expressed or implied by forward-looking statements include, but are not limited to, the following risks and uncertainties:

- risks related to the Incident and the ongoing impact to the Company;
- risks related to a redetermination of the borrowing base under the Company’s senior secured reserve-based revolving credit facility (the “Revolving Credit Facility”);
- the Company’s ability to access funds on acceptable terms, if at all, because of the terms and conditions governing its indebtedness, including financial covenants;
- the Company’s ability to satisfy its debt obligations;
- volatility in the prices for oil, natural gas and NGLs, including further or sustained declines in commodity prices;
- the potential for additional impairments due to continuing or future declines in oil, natural gas and NGL prices;
- the uncertainty inherent in estimating quantities of oil, natural gas and NGL reserves;
- the Company’s substantial future capital requirements, which may be subject to limited availability of financing;
- the uncertainty inherent in the development and production of oil and natural gas;
- the Company’s need to make accretive acquisitions or substantial capital expenditures to maintain its declining asset base;
- the existence of unanticipated liabilities or problems relating to acquired or divested businesses or properties;
- potential acquisitions, including the Company’s ability to make acquisitions on favorable terms or to integrate acquired properties;
- the consequences of changes the Company has made, or may make from time to time in the future, to its capital expenditure budget, including the impact of those changes on its production levels, reserves, results of operations and liquidity;

- potential shortages of, or increased costs for, drilling and production equipment and supply materials for production, such as CO_2;
- potential difficulties in the marketing of oil and natural gas;
- changes to the financial condition of counterparties;
- uncertainties surrounding the success of the Company's secondary and tertiary recovery efforts;
- competition in the oil and natural gas industry;
- the Company's results of evaluation and implementation of strategic alternatives;
- general political and economic conditions, globally and in the jurisdictions in which we operate, including escalating tensions between Russia and Ukraine and the potential destabilizing effect such conflict may pose for the European continent or the global oil and natural gas markets
- the impact of climate change and natural disasters, such as earthquakes, tidal waves, mudslides, fire and floods;
- the impact of legislation and governmental regulations, including those related to climate change and hydraulic fracturing;
- the risk that the Company's hedging strategy may be ineffective or may reduce our income;
- the cost and availability of insurance as well as operating risks that may not be covered by an effective indemnity or insurance;
- actions of third-party co-owners of interest in properties in which we also own an interest; and
- other risks and uncertainties described in "Item 1A. Risk Factors."

The forward-looking statements contained in this report are largely based on our expectations, which reflect estimates and assumptions made by the Company's management. These estimates and assumptions reflect the Company's best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond the Company's control. In addition, management's assumptions about future events may prove to be inaccurate. All readers are cautioned that the forward-looking statements contained in this report are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or that the events or circumstances described in any forward-looking statement will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to factors described in "Item 1A. Risk Factors" and elsewhere in this report. All forward-looking statements speak only as of the date of this report. We do not intend to update or revise any forward-looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on the Company's behalf.

RISK FACTOR SUMMARY

Our business is subject to numerous risks and uncertainties, including those highlighted in this section titled "Risk Factors" and summarized below. We have various types of risks, including risks related to our business and industry; information technology, data security and privacy; legal, regulatory, accounting, and tax matters; our Common Stock; and our Revolving Credit Facility, which are discussed more fully elsewhere in this Annual Report. As a result, this risk factor summary does not contain all of the information that may be important to you, and you should read this risk factor summary together with the more detailed discussion of risks and uncertainties set forth following this section under the heading "Risk Factors," as well as elsewhere in this Annual Report. These risks include, but are not limited to, the following:

- Our assumptions and estimates regarding the total aggregate costs associated with the Incident may be inaccurate, which could materially and adversely affect our business, results of operations and financial condition.
- We may be subject to increased permitting obligations and regulatory scrutiny as a result of the Incident.
- The shut-in of the pipeline could negatively impact our production, liquidity, and, ultimately, our operations, results, and performance.
- Oil, natural gas and NGL prices are volatile, due to factors beyond our control, and greatly affect our business, results of operations and financial condition. Any decline in, or sustained low levels of oil, natural gas and NGL prices will cause a decline in our cash flow from operations, which could materially and adversely affect our business, results of operations and financial condition.
- If commodity prices decline and/or remain depressed for a prolonged period, a significant portion of our development projects may become uneconomic and result in write downs of the value of our oil and natural gas properties, which may adversely affect our financial condition and our ability to fund our operations.
- A pandemic, epidemic or outbreak of an infectious disease, such as COVID-19, may materially adversely affect our business.
- We may be unable to maintain compliance with the covenants in the Revolving Credit Facility, which could result in an event of default thereunder that, if not cured or waived, would have a material adverse effect on our business and financial condition.
- Restrictive covenants in our Revolving Credit Facility could limit our growth and our ability to finance our operations, fund our capital needs, respond to changing conditions and engage in other business activities that may be in our best interests.
- Our variable rate indebtedness subjects us to interest rate risks, which could cause our debt service obligation to increase significantly.
- Our estimated reserves and future production rates are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our estimated reserves.
- The failure to replace our proved oil and natural gas reserves could adversely affect our business, financial condition, results of operations, production and cash flows.
- Many of our properties are in areas that may have been partially depleted or drained by offset wells.
- Our expectations for future development activities are planned to be realized over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of such activities.
- The inability of our significant customers to meet their obligations to us may adversely affect our financial results.
- We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations.

PART I

ITEM 1. BUSINESS

References

Amplify Energy Corp. (“Amplify Energy,” the “Company”, “we,” “us”, “our,” or similar terms), is a publicly traded Delaware corporation, in which our common stock is listed on the NYSE under the symbol “AMPY.”

Overview

Amplify Energy is an independent oil and natural gas company engaged in the acquisition, development, exploitation and production of oil and natural gas properties. Our management evaluates performance based on one reportable business segment, as the economic environments are not different within the operation of our oil and natural gas properties. Our business activities are conducted through OLLC, our wholly owned subsidiary, and its wholly owned subsidiaries. Our assets consist primarily of producing oil and natural gas properties located in Oklahoma, the Rockies (Bairoil), federal waters offshore Southern California (Beta), East Texas/North Louisiana, and Eagle Ford (Non-op). Most of our oil and natural gas properties are located in large, mature oil and natural gas reservoirs.

The Company’s properties consist primarily of operated and non-operated working interests in producing and undeveloped leasehold acreage and working interests in identified producing wells. As of December 31, 2021:

- Our total estimated proved reserves were approximately 121.2 MMBoe, of which approximately 43% were natural gas, 37% were oil and 20% were NGLs and 98% were classified as proved developed reserves;
- We produced from 2,417 gross (1,279 net) producing wells across our properties, with an average working interest of 53%, and the Company is the operator of record of the properties containing 92% of our total estimated proved reserves; and
- Our average net production for the three months ended December 31, 2021, was 20.8 MBoe/d, implying a reserve-to-production ratio of approximately 16 years.

Industry Trends

In March 2020, the World Health Organization classified the outbreak of COVID-19 as a global pandemic. In attempting to control the spread of COVID-19, governments around the world imposed laws and regulations such as shelter-in-place orders, quarantines, executive orders and similar restrictions. As a result, the global economy suffered a significant slowdown and uncertainty, which in turn led to a precipitous decline in commodity prices in response to decreased demand. Beginning in the first quarter of 2021 and continuing throughout the year, commodity prices have recovered substantially, due in part to the accessibility of vaccines, reopening of economies after lockdowns, and general optimism concerning the spread and severity of new variants of COVID-19 and the economic recovery. Despite recent downward trends in the spread of COVID-19, particularly as vaccination rates have increased, new variants of COVID-19 have intermittently emerged and spread throughout the U.S. and globally causing further uncertainty. This continued uncertainty and/or the emergence of new COVID-19 variants, including vaccine resistant variants, may result in additional adverse impacts on our results of operations, cash flows and financial position.

Recent Developments

Southern California Pipeline Incident

On October 2, 2021, contractors operating under the direction of Beta Operating Company, LLC (“Beta”), one of our subsidiaries, observed an oil sheen on the water approximately four miles off the coast of Newport Beach, California (the “Incident”). Beta platform personnel were notified and promptly initiated our Oil Spill Response Plan, which was reviewed and approved by the Bureau of Safety and Environmental Enforcement’s Oil Spill Preparedness Division within the United States Department of the Interior, and which included the required notifications of specified regulatory agencies. On October 3, 2021, a Unified Command, consisting of the Company, the U.S. Coast Guard and California Department of Fish and Wildlife’s Office of Spill Prevention and Response, was established to respond to the Incident.

On October 5, 2021, the Unified Command announced that reports from its contracted commercial divers and Remotely Operated Vehicle footage indicated that a 4,000-foot section of our pipeline had been displaced with a maximum lateral movement of approximately 105 feet and that the pipeline had a 13-inch split, running parallel to the pipe. On October 14, 2021, the U.S. Coast Guard announced that it had a high degree of confidence the size of the release was approximately 588 barrels of oil, which was below the previously reported maximum estimate of 3,134 barrels. On October 16, 2021, the U.S. Coast Guard announced that it had identified the Mediterranean Shipping Company (DANIT) as a "vessel of interest" and its owner Dordellas Finance Corporation and operator Mediterranean Shipping Company, S.A. as parties in interest in connection with an anchor-dragging incident in January 2021 (the "Anchor Dragging Incident"), which occurred in close proximity to our pipeline, and that additional vessels of interest continue to be investigated. On November 19, 2021, the U.S. Coast Guard announced that it had identified the COSCO (Beijing) as another vessel involved in the Anchor Dragging Incident and named its owner Capetanissa Maritime Corporation of Liberia and its operator V.Ships Greece Ltd. as parties in interest. The cause, timing and details regarding the Incident are currently under investigation and any information regarding the Incident is preliminary.

At the height of the Incident response, we deployed over 1,800 personnel working under the guidance and at the direction of the Unified Command to aid in cleanup operations. As of October 14, 2021, all beaches that had been closed following the Incident have reopened. On February 2, 2022, the Unified Command announced that response and monitoring efforts have officially concluded for the Incident, and Unified Command would stand down as of such date. Amplify is grateful to our Unified Command partners for their collaboration and professionalism over the course of the response.

In response to the Incident, all operations have been suspended and the pipeline has been shut-in until we receive the required regulatory approvals to begin operations. On October 4, 2021, the Pipeline and Hazardous Materials Safety Administration ("PHMSA"), Office of Pipeline Safety ("OPS") issued a Corrective Action Order ("CAO") pursuant to 49 U.S.C. § 60112, which makes clear that no restart of the affected pipeline may occur until PHMSA has approved a written restart plan. The California Coastal Commission ("CCC") has requested approval from the Office of Coastal Management for the National Oceanic and Atmospheric Association to conduct a Coastal Zone Management Act ("CZMA") consistency review of the U.S. Army Corps of Engineers Nationwide Permit ("NWP") 12 application for the proposed permanent repair permit. We are working expeditiously and cooperatively to comply with the requirements of the relevant agencies in order to gain such approvals and any other regulatory approvals that are necessary to permanently repair the pipeline and restart operations. As a result of the uncertainties related to the permitting and regulatory approval process, we can provide no assurances as to whether and when, if at all, we will be able to restart operations at the Beta field. At present no operations are underway in the Beta field.

We are currently subject to a number of ongoing investigations related to the Incident by certain federal and state agencies. To date, the U.S. Coast Guard, the U.S. Bureau of Ocean Energy Management, the U.S. Department of Justice, the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration, the U.S. Department of the Interior Bureau of Safety and Environmental Enforcement, the California Department of Justice, the Orange County District Attorney, the Los Angeles County District Attorney, and the California Department of Fish & Wildlife are conducting investigations or examinations of the Incident. Other federal agencies may or have commenced investigations and proceedings, and federal agencies such as the U.S. Environmental Protection Agency may initiate enforcement actions seeking penalties and other relief under the Clean Water Act and other statutes. Amplify continues to comply with all regulatory requirements and investigations. The outcomes of these investigations and the nature of any remedies pursued will depend on the discretion of the relevant authorities and may result in regulatory or other enforcement actions, as well as civil and criminal liability.

On December 15, 2021, a federal grand jury in the Central District of California returned a federal criminal indictment against Amplify Energy Corp., Beta Operating Company, LLC, and San Pedro Bay Pipeline Company in connection with the Incident. The indictment alleges that we committed a misdemeanor violation of the federal Clean Water Act for negligently discharging oil into the contiguous zone of the United States. The United States Attorney's Office for the Central District of California has stated that its investigation of the Incident and related matters is ongoing. State authorities are conducting parallel criminal investigations as well. We are continuing to cooperate with these federal and state investigations. The outcome of these investigations is uncertain, including whether they will result in additional criminal charges.

We and certain of our subsidiaries have been named as defendants in approximately 14 putative class action lawsuits, which have been consolidated into a single consolidated action in the United States District Court for the Central District of California. In the consolidated action, Plaintiffs filed an amended class action complaint on January 28, 2022. The amended complaint asserted claims against us and MSC Mediterranean Shipping Company, Dordellas Finance Corp., Costamare Shipping Co. S.A., and Capetanissa Maritime Corporation of Liberia. Resolution of the consolidated case may take considerable time, and it is not possible at this time to estimate our potential liability resulting from these actions. For additional discussion of the legal proceedings associated with the Incident, see "Part I — Item 3. Legal Proceedings," "Part II — Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Part III — Item 1A. Risk Factors — Risks Related to the Southern California Pipeline Incident."

Under the Oil Pollution Act of 1990, 33 U.S.C. S 2701 et seq. ("OPA 90"), our pipeline was designated by the U.S. Coast Guard as the source of the oil discharge and therefore we are financially responsible for remediation and for certain costs and economic damages as provided for in OPA 90, as well as certain natural resource damages associated with the spill and certain costs determined by federal and state trustees engaged in a joint assessment of such natural resource damages. We are currently processing covered claims under OPA 90 as expeditiously as possible. In addition, the Natural Resource Damage Assessment remains ongoing and therefore the extent, timing and cost of related to such assessment are difficult to project. While we anticipate insurance will reimburse us for expenses related to the Natural Resource Damage Assessment, any potentially uncovered expenses may be material and could impact our business, our and results of operations and could put pressure on our liquidity position going forward.

We currently estimate that the total costs we have incurred or will incur with respect to the Incident related to (i) actual and projected response and remediation expenses incurred under the direction of the Unified Command and (ii) estimates for certain legal fees, to be approximately $90.0 million to $110.0 million. These estimates consider currently available facts and presently enacted laws and regulations. We have made assumptions regarding (i) the probable and estimable amounts expected to be settled with certain vendors for response and remediation expenses and (ii) the resolution of certain third-party claims, excluding claims with respect to losses, which are not probable and reasonably estimable, and (iii) future claims and lawsuits. Our estimates do not include (i) the nature, extent and cost of future legal services that will be required in connection with all lawsuits, claims and other matters requiring legal or expert advice associated with the Incident, (ii) any lost revenue associated with the suspension of operations at Beta, (iii) any liabilities or costs that are not reasonably estimable at this time or that relate to contingencies where we currently regard the likelihood of loss as being only reasonably possible or remote and (iv) the future costs associated with the permanent repair of the pipeline and the restart of the Beta operations. We believe we have accrued adequate amounts for all probable and reasonably estimable costs; however, this estimate is subject to uncertainties associated with the assumptions that we have made. For example, settlements with vendors for response and remediation expenses could turn out to be significantly higher or lower than we have estimated. Accordingly, our assumptions and estimates may change in future periods based on future events and total costs may materially increase; therefore, we can provide no assurance that we will not have to accrue significant additional costs in future periods with respect to the Incident.

In accordance with customary insurance practice, we maintain insurance policies, including loss of production income insurance, against many potential losses or liabilities arising from our operations and at costs that we believe to be economic. We regularly review our risk of loss and the cost and availability of insurance and revise our insurance accordingly. Our insurance does not cover every potential risk associated with our operations and is subject to certain exclusions and deductibles. While we expect our insurance policies will cover a material portion of the total aggregate costs associated with the Incident, including but not limited to response and remediation expenses, defense costs and loss of revenue resulting from suspended operations, we can provide no assurance that our coverage will adequately protect us against liability from all potential consequences, damages and losses related to the Incident and such view and understanding is preliminary and subject to change.

As of December 31, 2021, we have incurred total aggregate gross costs of $99.0 million, of which we have received or believes that it is probable that we will receive $97.4 million in insurance recoveries. Our net charge of $1.6 million, which is classified as "Pipeline Incident Loss" on our Consolidated Statements of Operations, reflects insurance deductibles and legal costs incurred to date that are not currently expected to be recovered under an insurance policy.

Through December 31, 2021, we had collected $48.3 million out of the approximate $97.4 million of costs that we believe are probable of recovery from insurance carriers, net of deductibles. Therefore, as of December 31, 2021, we have recognized a receivable of approximately $49.1 million for the portion of costs that we believe is probable of recovery from insurance, net of deductibles and amounts collected during 2021. Subsequent to December 31, 2021, for the period January 1, 2022 through March 1, 2022, we received insurance cost recoveries of $22.1 million.

Additionally, during 2021, we recognized $6.7 million related to approved LOPI insurance claims, which is classified as "Other Revenues" in the Company's Consolidated Statement of Operations. Subsequent to December 31, 2021, for the period January 1, 2022 through March 1, 2022, we received the entire LOPI insurance claim settlement of $6.7 million. For additional discussion of the risks associated with the Incident, see "Item 1A. Risk Factors — Risks Related to the Southern California Pipeline Incident."

Director Departures

On March 7, 2022, each of David Proman and Evan Lederman resigned from the Company's Board of Directors, effective as of such date. Mr. Proman and Mr. Lederman are each stepping down to focus on other professional ventures. The Company's Board of Directors is working with a nationally recognized search firm to identify and evaluate new independent director candidates and is engaging with shareholders to gather input on relevant qualifications and candidates.

Properties

We engaged Cawley, Gillespie and Associates, Inc. ("CG&A"), our independent reserve engineers, to prepare our reserves estimates for all of our proved reserves at December 31, 2021 and 2020. The following table summarizes information, based on a reserve report prepared by CG&A (which we refer to as our "reserve report"), about our proved oil and natural gas reserves by geographic region as of December 31, 2021, and our average net production for the three months ended December 31, 2021:

	Estimated Net Proved Reserves					Average Net Production		Average		
Region	MMBoe (1)	% Oil and NGL	% Natural Gas	% Proved Developed	Standardized Measure (2)	MBoe/d	% of Total	Reserve-to Production Ratio (3)	Producing Wells Gross	Net
					(in millions)			(Years)		
Oklahoma	35.0	47 %	53 %	100 %	$ 268.9	6.3	30 %	15.2	326	233
Rockies (Bairoil)	26.6	100 %	— %	100 %	218.3	3.6	18 %	20.1	137	137
Southern California (Beta) (4)	12.0	100 %	— %	100 %	128.2	0.1	— %	584.4	—	—
East Texas/ North Louisiana	44.5	25 %	75 %	98 %	250.0	9.6	46 %	12.7	1,592	885
Eagle Ford (Non-Op)	3.1	91 %	9 %	56 %	54.4	1.2	6 %	7.0	362	24
Total	121.2	57 %	43 %	98 %	$ 919.8	20.8	100 %	16.0	2,417	1,279

(1) Determined using a ratio of six Mcf of natural gas to one Bbl of oil, condensate or NGLs based on an approximate energy equivalency. This is an energy content correlation and does not reflect a value or price relationship between the commodities.

(2) Standardized measure is calculated in accordance with Accounting Standards Codification, or ASC, Topic 932, *Extractive Activities—Oil and Gas,* and is calculated using SEC pricing, before market differentials, of $66.56 Bbl for crude oil and NGLs and $3.60 MMBtu for natural gas.

(3) The average reserve-to-production ratio is calculated by dividing estimated net proved reserves as of December 31, 2021 by the annualized average net production for the three months ended December 31, 2021.

(4) On October 2, 2021, the Beta field was shut-in due to the pipeline incident as discussed above. For the three months ended December 31, 2021, we had net production of 0.06 Boe/d. Due to suspension of operations at Beta, the average reserve-to-production ratio at Beta is substantially higher as we have 12.0 MMBoe of estimated net reserves at December 31, 2021. All of Beta's proved developed producing reserves have been reclassified as proved developed non-producing at December 31, 2021.

Our Areas of Operation

Oklahoma

Approximately 29% of our estimated proved reserves as of December 31, 2021 and approximately 30% of our average daily net production for the three months ended December 31, 2021 were located in the Oklahoma region. Our Oklahoma properties include wells and properties primarily located in Alfalfa and Woods counties in Oklahoma. Those properties collectively contained 35.0 MMBbls of estimated net proved reserves as of December 31, 2021 based on our reserve report and generated average net production of 6.3 MBoe/d for the three months ended December 31, 2021.

Rockies (Bairoil)

Approximately 22% of our estimated proved reserves as of December 31, 2021 and approximately 17% of our average daily net production for the three months ended December 31, 2021 were located in the Rockies region. Our Rockies properties include wells and properties primarily located in the Lost Soldier and Wertz fields in Wyoming at our Bairoil complex. Our Rockies properties contained 26.6 MMBbls of estimated net proved oil and NGLs reserves as of December 31, 2021 based on our reserve report and generated average net production of 3.6 MBoe/d for the three months ended December 31, 2021.

Southern California (Beta)

For a discussion regarding the Southern California Pipeline Incident, see “Item 1. Business — Recent Developments — Southern California Pipeline Incident.”

Approximately 10% of our estimated proved reserves as of December 31, 2021 and approximately 0.3% of our average daily net production for the three months ended December 31, 2021 were located in federal waters offshore Southern California. These properties (the “Beta Properties”) consist of: 100% of the working interests and currently 87.6% average net revenue interest in three Pacific Outer Continental Shelf lease blocks (P-0300, P-0301 and P-0306) (referred to as the “Beta Unit”), in the Beta field located in federal waters approximately 11 miles offshore from the Port of Long Beach, California. Our Beta Properties contained 12.0 MMBbls of estimated net proved oil reserves as of December 31, 2021 based on our reserve report and generated average net production of 0.1 MBoe/d for the three months ended December 31, 2021. Oil and gas are produced from the Beta Unit via two production platforms, referred to as the Ellen and Eureka platforms, equipped with permanent drilling rigs and associated equipment. On a third platform, Elly, the oil, water and gas are separated, and the oil is prepared for sale, while the gas is burned as fuel for power and the water is recycled back into the reservoir for pressure maintenance. Sales quality oil is then pumped from the Elly platform to the Beta pump station located onshore at the Port of Long Beach, California via a 16-inch diameter oil pipeline, which extends approximately 17.5 miles. Amplify Energy’s wholly owned subsidiary, San Pedro Bay Pipeline Company owns and operates the pipeline system.

On, June 24, 2020, the Bureau of Safety and Environmental Enforcement (“BSEE”) informed the Company that it had been approved for the Special Case Royalty Relief for the Company’s interests in the Beta Unit, effective beginning July 1, 2020. The royalty rates were reduced from 25% to 12.5% for two of the Company’s leases and from 16.67% to 8.33% for the remaining third lease. This resulted in the Company’s average net revenue interest increasing from 75.2% to 87.6%.

The Special Case Royalty Relief is subject to two key provisions related to commodity prices and capital investment. Special Case Royalty Relief will be suspended in months in which the weighted twelve-month average NYMEX oil and Henry Hub gas price exceeds $66.19 per BOE, which represents a 25% premium to the average realized price recognized by the Company during the qualification period of April 2019 to March 2020. The Special Case Royalty Relief would terminate in the event that the Company generates no benefit from the reduced rates due to the higher realized pricing for 12 consecutive months. In addition, Special Case Royalty Relief requires that during the two-year period ending June 30, 2022 (and annually thereafter), the cumulative amount of a) development costs and b) incremental royalties must exceed the value of the royalty relief benefits received by the Company for production volumes at or below the calculated production volume during the qualification period. On February 25, 2022, Amplify received a letter from BSEE informing the Company that Special Case Royalty Relief will be suspended for the month of January. Amplify further anticipates that it will not satisfy the conditions described above required for Special Case Royalty Relief beginning on July 1, 2022.

East Texas / North Louisiana

Approximately 37% of our estimated proved reserves as of December 31, 2021 and approximately 46% of our average daily net production for the three months ended December 31, 2021 were located in the East Texas/ North Louisiana region. Our East Texas/ North Louisiana properties include wells and properties primarily located in the Joaquin, Carthage, Willow Springs and East Henderson fields in East Texas. Those properties collectively contained 44.5 MMBoe of estimated net proved reserves as of December 31, 2021 based on our reserve report and generated average net production of 9.6 MBoe/d for the three months ended December 31, 2021.

Eagle Ford (Non-Op)

Approximately 3% of our estimated proved reserves as of December 31, 2021 and approximately 6% of our average daily net production for the three months ended December 31, 2021 were located in the Eagle Ford region. Our Eagle Ford properties include wells and properties in fields located primarily in the Eagleville fields. Our Eagle Ford properties contained 3.1 MMBoe of estimated net proved reserves as of December 31, 2021 based on our reserve report. Those properties collectively generated average net production of 1.2 MBoe/d for the three months ended December 31, 2021.

Our Oil and Natural Gas Data

Our Reserves

Internal Controls. Our proved reserves were estimated at the well or unit level for reporting purposes by CG&A, our independent reserve engineers. We maintain internal evaluations of our reserves in a secure reserve engineering database. CG&A interacts with our internal petroleum engineers and geoscience professionals in each of our operating areas and with operating, accounting, and marketing employees to obtain the necessary data to prepare our proved reserves report. Reserves are reviewed and approved internally by our senior management on an annual basis and evaluated by our lender group on at least a semi-annual basis in connection with borrowing base redeterminations under our Revolving Credit Facility. Our reserve estimates are prepared by CG&A at least annually.

Our internal professional staff works closely with CG&A to ensure the integrity, accuracy and timeliness of data that is furnished to them in order to prepare the reserves report. All of the reserve information maintained in our secure reserve engineering database is provided to the external engineers. In addition, we provide CG&A with other pertinent data, such as seismic information, geologic maps, well logs, production tests, material balance calculations, well performance data, operating procedures and relevant economic criteria. We make all requested information, as well as our pertinent personnel, available to the external engineers as part of their preparation of our reserves.

Qualifications of Responsible Technical Persons

Internal Engineers. Tony Lopez is the technical person at the Company, primarily responsible for overseeing and providing oversight of the preparation of the reserves estimates with our third-party reserve engineers.

Mr. Lopez has over 15 years of corporate reserve reporting experience. Mr. Lopez joined the Company as Vice President of Corporate Reserves in June 2018 and currently serves as the Company's Senior Vice President of Engineering & Exploitation. Prior to that Mr. Lopez was Vice President of Acquisitions and Engineering for EnerVest, Ltd., where he managed the corporate reserve reporting process and the financial planning & analysis department. Mr. Lopez is a graduate of West Virginia University and holds a B.S. in Petroleum and Natural Gas Engineering. Mr. Lopez is an active member of the Society of Petroleum Engineers.

Cawley, Gillespie and Associates Inc. CG&A is an independent oil and natural gas consulting firm. No director, officer, or key employee of CG&A has any financial ownership in us or any of our affiliates. CG&A's compensation for the preparation of its report is not contingent upon the results obtained and reported. CG&A has not performed other work for us or any of our affiliates that would affect its objectivity. The estimates of our proved reserves presented in the CG&A reserve report were overseen by Todd Brooker.

Mr. Brooker is the President of CG&A and has been an employee of CG&A since 1992. His responsibilities include reserve and economic evaluations, fair market valuations, field studies, pipeline resource studies and acquisition/divestiture analysis. His reserve reports are routinely used for public company SEC disclosures. Prior to joining CG&A, Mr. Brooker worked in Gulf of Mexico drilling and production engineering at Chevron Corporation. Mr. Brooker's experience includes significant projects in both conventional and unconventional resources in every major U.S. producing basin and abroad, including oil and gas shale plays, coalbed methane fields, waterfloods and complex, faulted structures.

Mr. Brooker graduated with honors from the University of Texas at Austin in 1989 with a Bachelor of Science degree in Petroleum Engineering and is a registered Professional Engineer in the State of Texas. He is also a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers and the Society of Petroleum Evaluation Engineers.

Estimated Proved Reserves

The following table presents the estimated net proved oil and natural gas reserves attributable to our properties and the standardized measure associated with the estimated proved reserves attributable to our properties as of December 31, 2021, based on the prepared reserve report by CG&A, our independent reserve engineers. The standardized measure shown in the table is not intended to represent the current market value of our estimated oil and natural gas reserves.

	Reserves			
	Oil (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	Total (MBoe) (1)
Estimated Proved Reserves				
Developed	43,857	309,794	23,574	119,063
Undeveloped	1,144	4,556	263	2,167
Total	45,001	314,350	23,837	121,230
Proved developed reserves as a percentage of total proved reserves				98 %
Standardized measure (in thousands) (2)				$ 919.8
Oil and Natural Gas Prices (3)				
Oil – WTI per Bbl				$ 66.56
Natural gas – Henry Hub per MMBtu				$ 3.60

(1) Determined using a ratio of six Mcf of natural gas to one Bbl of oil, condensate or NGLs based on an approximate energy equivalency. This is an energy content correlation and does not reflect a value or price relationship between the commodities.

(2) Standardized measure is the present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC without giving effect to non-property related expenses, such as general and administrative expenses, interest expense, or to depletion, depreciation and amortization. The future cash flows are discounted using an annual discount rate of 10%. Standardized measure does not give effect to derivative transactions. For a description of our commodity derivative contracts, see "Item 1. Business — Operations — Derivative Activities" as well as "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Commodity Derivative Contracts."

(3) Our estimated net proved reserves and related standardized measure were determined using 12-month trailing average oil and natural gas index prices, calculated as the unweighted arithmetic average for the first-day-of-the-month price for each month in effect as of the date of the estimate, without giving effect to derivative contracts, held constant throughout the life of the properties. These prices were adjusted by lease for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead.

The data in the table above represents estimates only. Oil and natural gas reserve engineering is inherently a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured exactly. The accuracy of any reserve estimate is a function of the quality of available data and engineering and geological interpretation and judgment. Accordingly, reserve estimates may vary from the quantities of oil and natural gas that are ultimately recovered. For a discussion of risks associated with internal reserve estimates, see "Item 1A. Risk Factors — Risks Related to Our Business — Our estimated reserves and future production rates are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our estimated reserves."

Future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. The standardized measure shown above should not be construed as the current market value of our estimated oil and natural gas reserves. The 10% discount factor used to calculate standardized measure, which is required by the SEC and FASB, is not necessarily the most appropriate discount rate. The present value, no matter what discount rate is used, is materially affected by assumptions as to timing of future production, which may prove to be inaccurate.

Development of Proved Undeveloped Reserves

As of December 31, 2021, we had 2.2 MMBoe of proved undeveloped reserves ("PUDs") comprised of 1.1 MMBbls of oil, 4.6 Bcfe of natural gas and 0.3 MMBbls of NGLs. None of our proved undeveloped reserves as of December 31, 2021 are scheduled to be developed on a date more than five years from the date the reserves were initially booked as PUDs. PUDs will be converted from undeveloped to developed as the applicable wells begin production.

For the year ended December 31, 2021, total proved undeveloped reserves decreased by 15.0 MMBoe. The Company has shifted its resources to returning Beta to production, which has resulted in a modification to the Company's future PUD development plans. These changes have resulted in a decrease of 16.0 MMBoe due to removed PUD locations in Oklahoma, Rockies and California. The Company also had 1.0 MMBoe transfer to proved developed properties on certain non-operated properties in Eagle Ford. The Company also had 2.0 MMBoe of extensions and discoveries primarily related to wells in progress at year end in the Eagle Ford and East Texas.

Approximately 2.9% (1 MMBoe) of our PUDs recorded as of December 31, 2020 were developed during the twelve months ended December 31, 2021. Total costs incurred to develop these PUDs were approximately $6.0 million, of which $2.9 million was incurred in fiscal year 2020 and $3.1 million incurred in fiscal year 2021. In total, we incurred total capital expenditures of approximately $4.1 million during fiscal year 2021 developing PUDs, which includes $1.0 million associated with PUDs to be completed in 2022. Based on our current expectations of our cash flows, we believe that we can fund the drilling of our current PUD inventory and our expansions in the next five years from our cash flow from operations and borrowings under our Revolving Credit Facility. For a more detailed discussion of our liquidity position, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources."

Production, Revenue and Price History

For a description of our production, revenues, and average sales prices and per unit costs, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Results of Operations."

The following tables summarize our average net production, average unhedged sales prices by product and average production costs (not including ad valorem and severance taxes) by geographic region for the years ended December 31, 2021 and 2020, respectively:

	For the Year Ended December 31, 2021								
	Oil		NGLs		Natural Gas		Total		
	Production Volumes (MBbls)	Average Sales Price ($/Bbl)	Production Volumes (MBbls)	Average Sales Price ($/Bbl)	Production Volumes (MMcf)	Average Sales Price ($/Mcf)	Production Volumes (MBoe)	Average Sales Price ($/Boe)	Lease Operating Expense ($/Boe)
Oklahoma	517	$ 66.63	659	$ 27.68	7,246	$ 2.98	2,381	$ 31.21	$ 6.90
Rockies (Bairoil)	1,336	62.20	—	—	—	—	1,336	62.20	32.64
Southern California (Beta) (1)	996	61.77	—	—	—	—	996	61.77	37.50
East Texas/ North Louisiana	169	64.88	719	29.41	16,268	3.67	3,599	25.49	5.23
Eagle Ford (Non-Op)	333	67.25	52	29.11	294	3.90	435	57.68	11.93
Total	3,351	$ 63.43	1,430	$ 28.62	23,808	$ 3.46	8,747	$ 38.39	$ 13.88
Average net production (MBoe/d)							24.0		

(1) On October 2, 2021, the Beta field was shut-in after the Incident and therefore the table above reflects only nine months of activity.

	For the Year Ended December 31, 2020								
	Oil		NGLs		Natural Gas		Total		
	Production Volumes (MBbls)	Average Sales Price ($/Bbl)	Production Volumes (MBbls)	Average Sales Price ($/Bbl)	Production Volumes (MMcf)	Average Sales Price ($/Mcf)	Production Volumes (MBoe)	Average Sales Price ($/Boe)	Lease Operating Expense ($/Boe)
Oklahoma	687	$ 36.84	857	$ 10.75	9,395	$ 0.93	3,109	$ 13.90	$ 6.14
Rockies (Bairoil)	1,493	34.55	—	—	—	—	1,493	34.55	28.84
Southern California (Beta)	1,255	36.10	—	—	—	—	1,255	36.10	27.98
East Texas/ North Louisiana	198	35.37	836	12.52	17,905	1.87	4,018	12.68	4.33
Eagle Ford (Non-Op)	254	35.75	32	11.99	173	2.01	315	31.14	16.05
Total	3,887	$ 35.58	1,725	$ 11.63	27,473	$ 1.55	10,190	$ 19.71	$ 11.75
Average net production (MBoe/d)							27.8		

Productive Wells

Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we own an interest and net wells are the sum of our fractional working interests owned in gross wells. The following table sets forth information relating to the productive wells in which we owned a working interest as of December 31, 2021.

	Oil		Natural Gas	
	Gross	Net	Gross	Net
Operated (1)	405	367	957	804
Non-operated	456	39	599	69
Total	861	406	1,556	873

(1) Our operated properties reflect all operated proved devolved producing properties at December 31, 2021. For the year end reserves Beta is excluded from the amount as the assets were reclassified as proved developed producing reserves to proved developed non-producing at December 31, 2021.

Developed Acreage

Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary. As of December 31, 2021, substantially all of our leasehold acreage was held by production. The following table sets forth information as of December 31, 2021 relating to our leasehold acreage.

Region	Developed Acreage (1)	
	Gross (2)	Net (3)
Oklahoma	112,221	94,464
Rockies (Bairoil)	6,653	6,653
Southern California (Beta)	17,280	17,280
East Texas/ North Louisiana	256,947	195,479
Eagle Ford (Non-Op)	14,167	811
Total	407,268	314,687

(1) Developed acres are acres spaced or assigned to productive wells or wells capable of production.
(2) A gross acre is an acre in which we own a working interest. The number of gross acres is the total number of acres in which we own a working interest.
(3) A net acre is deemed to exist when the sum of our fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Undeveloped Acreage

The following table sets forth information as of December 31, 2021 relating to our undeveloped leasehold acreage, which are held by production (including the remaining terms of leases and concessions).

	Undeveloped Acreage		Net Acreage Subject to Lease Expiration by Year	
Region	Gross (1)	Net (2)	2022	2023
Oklahoma	12,002	1,758	—	—

(1) A gross acre is an acre in which we own a working interest. The number of gross acres is the total number of acres in which we own a working interest.
(2) A net acre is deemed to exist when the sum of our fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Drilling Activities

Our drilling activities primarily consist of development wells. The following table sets forth information with respect to (i) wells drilled and completed during the periods indicated and (ii) wells drilled in a prior period but completed during the periods indicated. The information should not be considered indicative of future performance, nor should a correlation be assumed between the number of productive wells drilled, quantities of reserves found or economic value. At December 31, 2021, 15 gross (1 net) wells were in various stages of completion.

	For the Year Ended December 31,			
	2021		2020	
	Gross	Net	Gross	Net
Development wells:				
Productive	36.0	1.0	22.0	1.0
Dry	—	—	—	—
Exploratory wells:				
Productive	—	—	—	—
Dry	—	—	—	—
Total wells:				
Productive	36.0	1.0	22.0	1.0
Dry	—	—	—	—
Total	36.0	1.0	22.0	1.0

Delivery Commitments

We have no commitments to deliver a fixed and determinable quantity of our oil or natural gas production in the near future under our existing sales contracts.

We have entered into a long-term gas gathering agreement associated with a certain portion of our East Texas production with a third-party midstream service provider that has volumetric requirements. We also have a long-term contract associated with our NGL production in Oklahoma that is subject to a volume obligation. Information regarding our delivery commitments under these contracts is contained in Note 16 of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data," contained herein.

Operations

General

As of December 31, 2021, the Company is the operator of record of properties containing 92% of our total estimated proved reserves. We design and manage the development, recompletion and/or workover operations, and supervise other operation and maintenance activities for all of the wells we operate. We do not own the drilling rigs or other oil field services equipment used for drilling or maintaining wells on our onshore properties; independent contractors provide all the equipment and personnel associated with these activities. Our Beta platforms have permanent drilling systems in place.

Marketing and Major Customers

The following individual customers each accounted for 10% or more of our total reported revenues for the period indicated:

	For the Year Ended December 31,	
	2021	2020
Major customers:		
Sinclair Oil & Gas Company	20 %	21 %
Phillips 66	19 %	23 %
ETC Texas Pipeline LTD	12 %	n/a
BP America Production Company	n/a	17 %

The production sales agreements covering our properties contain customary terms and conditions for the oil and natural gas industry and provide for sales based on prevailing market prices. A majority of those agreements have terms that renew on a month-to-month basis until either party gives advance written notice of termination.

If we were to lose any one of our customers, the loss could temporarily delay production and sale of a portion of our oil and natural gas in the related producing region. If we were to lose any single customer, we believe we could identify a substitute customer to purchase the impacted production volumes. However, if one or more of our larger customers ceased purchasing oil or natural gas altogether and we were unable to replace them, the loss of any such customer could have a detrimental effect on our production volumes and revenues in general.

Title to Properties

We believe that we have satisfactory title to all of our producing properties in accordance with industry standards. More thorough title investigations are customarily made before the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties. Individual properties may be subject to burdens that we believe do not materially interfere with the use or affect the value of the properties. As is customary in the industry, in the case of undeveloped properties, often cursory investigation of record title is made at the time of lease acquisition. Burdens on properties may include customary royalty interests, liens incident to operating agreements and for current taxes, obligations or duties under applicable laws, development obligations under natural gas leases, or net profits interests.

Derivative Activities

We enter into commodity derivative contracts with unaffiliated third parties, generally lenders under our Revolving Credit Facility or their affiliates, to achieve more predictable cash flows and to reduce our exposure to fluctuations in oil and natural gas prices. We intend to enter into commodity derivative contracts at times and on terms desired to maintain a portfolio of commodity derivative contracts covering at least 30% - 60% of our estimated production from total proved developed producing reserves over a one-to-three-year period at any given point of time. We may, however, from time to time, hedge more or less than this approximate amount.

Periodically, we enter into interest rate swaps to mitigate exposure to market rate fluctuations by converting variable interest rates (such as those in our Revolving Credit Facility) to fixed interest rates.

It is our policy to enter into derivative contracts only with creditworthy counterparties, which generally are financial institutions, deemed by management as competent and competitive market makers. Some of the lenders, or certain of their affiliates, under our Revolving Credit Facility are counterparties to our derivative contracts. We will continue to evaluate the benefit of employing derivatives in the future.

Competition

We operate in a highly competitive environment for acquiring properties, leasing acreage, contracting for drilling equipment and securing trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. As a result, our competitors may be able to pay more for productive oil and natural gas properties and exploratory prospects, as well as evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional properties and to find and develop reserves will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, there is substantial competition for capital available for investment in the oil and natural gas industry and many of our competitors have access to capital at a lower cost than that available to us.

Seasonal Nature of Business

The price we receive for our natural gas production is impacted by seasonal fluctuations in demand for natural gas. The demand for natural gas typically peaks during the coldest months and tapers off during the milder months, with a slight increase during the summer to meet the demands of electric generators. The weather during any particular season can affect this cyclical demand for natural gas. Seasonal anomalies such as mild winters or hot summers can lessen or intensify this fluctuation. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations.

Hydraulic Fracturing

We use hydraulic fracturing as a means to maximize the productivity of almost every well that we drill and complete, except in our offshore wells. Hydraulic fracturing is a necessary part of the completion process because our properties are dependent upon our ability to effectively fracture the producing formations in order to produce at economic rates. Our proved non-producing and proved undeveloped reserves make up 21.4% of the total proved reserves, with approximately 28.4% of these requiring hydraulic fracturing as of December 31, 2021.

We believe we have followed and continue to substantially follow applicable industry standard practices and legal and regulatory requirements for groundwater protection in our hydraulic fracturing operations, which are subject to supervision by state and federal regulators (including the U.S. Bureau of Land Management (the "BLM") on federal acreage). These protective measures include setting surface casing at a depth sufficient to protect fresh water zones as determined by regulatory agencies and cementing the well to create a permanent isolating barrier between the casing pipe and surrounding geological formations. This aspect of well design is intended to essentially eliminate a pathway for the fracturing fluid to contact any aquifers during the hydraulic fracturing operations. For recompletions of existing wells, the production casing is pressure tested prior to perforating the new completion interval.

Injection rates and pressures are monitored instantaneously and in real time at the surface during our hydraulic fracturing operations. Pressure is monitored on both the injection string and the immediate annulus to the injection string. Hydraulic fracturing operations would be shut down immediately if an abnormal change occurred to the injection pressure or annular pressure.

Certain state regulations require disclosure of the components in the solutions used in hydraulic fracturing operations. Approximately 99% of the hydraulic fracturing fluids we use are made up of water and sand, and the fluids are managed and used in accordance with applicable requirements.

Hydraulic fracture stimulation requires the use of a significant volume of water. Upon flowback of the water, we dispose of it into approved disposal or injection wells. We currently do not discharge water to the surface.

For information regarding existing and proposed governmental regulations regarding hydraulic fracturing and related environmental matters, see "— Environmental, Occupational Health and Safety Matters and Regulations — Hydraulic Fracturing."

Insurance

In accordance with customary industry practice, we maintain insurance against many, but not all, potential losses or liabilities arising from our operations and at costs that we believe to be economic. We regularly review our risks of loss and the cost and availability of insurance and revise our insurance accordingly. Our insurance does not cover every potential risk associated with our operations, including the potential loss of significant revenues. We can provide no assurance that our coverage will adequately protect us against liability from all potential consequences, damages and losses. We currently have insurance policies that include the following:

- Commercial General Liability;
- Primary Umbrella / Excess Liability;
- Property;
- Workers' Compensation;
- Employer's Liability;
- Maritime Employer's Liability;
- U.S. Longshore and Harbor Workers';
- Energy Package/Control of Well;
- Loss of Production Income (offshore only);
- Cybersecurity
- Oil Pollution Act Liability;
- Pollution Legal Liability;
- Charterer's Legal Liability;
- Non-Owned Aircraft Liability;
- Automobile Liability;
- Directors & Officers Liability;
- Employment Practices Liability;
- Crime; and
- Fiduciary Liability.

We continuously monitor regulatory changes and comments and consider their impact on the insurance market, along with and our overall risk profile. As necessary, we will adjust our risk and insurance program to provide protection at a level we consider appropriate while weighing the cost of insurance against the potential and magnitude of disruption to our operations and cash flows. Changes in laws and regulations could lead to changes in underwriting standards, limitations on scope and amount of coverage, and higher premiums, including possible increases in liability caps for claims of damages from oil spills.

Environmental, Occupational Health and Safety Matters and Regulations

General

Our oil and natural gas development and production operations are subject to stringent and complex federal, state and local laws and regulations governing the discharge of materials into the environment, health and safety aspects of our operations, or otherwise relating to protection of the environment and natural resources. These laws and regulations impose numerous obligations applicable to our operations, including the acquisition of certain permits before conducting regulated drilling activities; the restriction of types, quantities and concentration of materials that can be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands, seismically active areas and other protected areas; the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from our operations. Numerous governmental authorities, such as the U.S. Environmental Protection Agency ("EPA") and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly compliance or corrective actions. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, the imposition of investigatory or remedial obligations, the suspension or revocation of necessary permits, licenses and authorizations, the requirement that additional pollution controls be installed and in some instances, the issuance of orders limiting or prohibiting some or all of our operations. We may also experience delays in obtaining or be unable to obtain required permits, which may delay or interrupt our operations and limit our growth and revenue. In addition, the long-term trend in environmental regulation has been to place more restrictions and limitations on activities that may affect the environment and thus, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations.

Under certain environmental laws that impose strict as well as joint and several liability, we may be required to remediate contaminated properties currently or formerly owned or operated by us or facilities of third parties that received waste generated by our operations regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. Moreover, public interest in the protection of the environment has increased in recent years. New laws and regulations continue to be enacted, particularly at the state level, and the long-term trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. To the extent new or more stringent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business, prospects, financial condition or results of operations could be materially adversely affected.

The following is a summary of the more significant existing environmental, occupational health and safety laws and regulations to which our business operations are subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

Offshore Operations

Our oil and gas operations associated with our Beta Properties are conducted on offshore leases in federal waters and those operations are regulated by agencies such as the Bureau of Ocean Energy Management ("BOEM") and the BSEE, which have broad authority to regulate our oil and gas operations associated with our Beta Properties.

BOEM is responsible for managing environmentally and economically responsible development of the nation's offshore resources. Its functions include offshore leasing, resource evaluation, review and administration of oil and gas exploration and development plans, renewable energy development, and National Environmental Policy Act ("NEPA") analysis and environmental review. Lessees must obtain BOEM approval for exploration, development and production plans prior to the commencement of offshore operations. BOEM generally requires that lessees have substantial net worth, post supplemental bonds or provide other acceptable assurances that the obligations will be met. In October 2020, BOEM and BSEE issued a proposed rule to clarify, streamline, and provide greater transparency to financial assurance requirements for the oil and gas industry, including streamlining the evaluation criteria for determining if and when additional security is required for Outer Continental Shelf ("OCS") leases, pipeline rights-of-way and rights-of-use and easement and revising the process for issuing decommissioning obligations for facilities on the OCS. The new criteria may require lessees or operators to take additional steps to demonstrate that they have the financial ability to carry out their lease obligations. It is unclear whether BOEM and BSEE will finalize this rule, however, in August 2021, BOEM announced its continuing industry-wide efforts to seek supplemental financial assurance to cover expected decommissioning costs of certain oil and gas infrastructure, primarily focused in the OCS.

BSEE is responsible for safety and environmental oversight of offshore oil and gas operations. Its functions include the development and enforcement of safety and environmental regulations, permitting offshore exploration, development and production, inspections, offshore regulatory programs, oil spill response and training and environmental compliance programs. BSEE regulations require offshore production facilities and pipelines located on the OCS to meet stringent engineering and construction specifications, and BSEE has proposed and/or promulgated additional safety-related regulations concerning the design and operating procedures of these facilities and pipelines, including regulations to safeguard against or respond to well blowouts and other catastrophes. BSEE regulations also restrict the flaring or venting of natural gas, prohibit the flaring of liquid hydrocarbons and govern the plugging and abandonment of wells located offshore and the installation and removal of all fixed drilling and production facilities.

BOEM and BSEE have adopted regulations providing for enforcement actions, including civil penalties and lease forfeiture or cancellation for failure to comply with regulatory requirements for offshore operations. If we fail to pay royalties or comply with safety and environmental regulations, BOEM and BSEE may require that our operations on the Beta Properties be suspended or terminated and we may be subject to civil or criminal liability.

In November 2018, a federal court prohibited BOEM and BSEE from approving any plans or issuing permits involving hydraulic fracturing and/or acid well stimulation on the Pacific OCS until the agencies complete consultation with the U.S. Fish and Wildlife Service under the Endangered Species Act (the "ESA") and submit a consistency determination under the Coastal Zone Management Act to the California Coastal Commission. Although we do not use either hydraulic fracturing or acid stimulation routinely in connection with our operations on the Beta Properties, delays in the approval or refusal of plans and issuance of permits by BOEM or BSEE because of staffing, economic, environmental, legal or other reasons (or other actions taken by BOEM or BSEE) could adversely affect our offshore operations. The requirements imposed by BOEM and BSEE regulations are frequently changed and subject to new interpretations. Also, in addition to permits and approvals required by BOEM and BSEE, approvals and permits may be required from other agencies for the oil and gas operations associated with our Beta Properties, such as the U.S. Coast Guard, the EPA, U.S. Department of Transportation, U. S. Army Corps of Engineers and the South Coast Air Quality Management District.

Hazardous Substances and Waste Handling

Our operations are subject to environmental laws and regulations relating to the management and release of hazardous substances, solid and hazardous wastes and petroleum hydrocarbons. These laws generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous waste and may impose strict and, in some cases, joint and several liability for the investigation and remediation of affected areas where hazardous substances may have been released or disposed. The Comprehensive Environmental Response, Compensation and Liability Act, as amended ("CERCLA"), also referred to as the Superfund law and comparable state laws, impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons deemed "responsible parties." These persons include current owners or operators of the site where a release of hazardous substances occurred, prior owners or operators that owned or operated the site at the time of the release or disposal of hazardous substances and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these persons may be subject to strict and joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover the costs they incur from the responsible classes of persons. Despite the "petroleum exclusion" of Section 101(14) of CERCLA, which currently encompasses natural gas, we may nonetheless handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment. Also, comparable state statutes may not contain a similar exemption for petroleum, and it is also not uncommon for neighboring landowners and other third parties to file common law-based claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. In addition, we may have liability for releases of hazardous substances at our properties by prior owners or operators or other third parties.

The Oil Pollution Act of 1990 ("OPA") is the primary federal law imposing oil spill liability. The OPA contains numerous requirements relating to the prevention of, and response to petroleum releases into waters of the United States, including the requirement that operators of offshore facilities and certain onshore facilities near or crossing waterways must maintain certain significant levels of financial assurance to cover potential environmental cleanup and restoration costs. Under the OPA, strict, joint and several liability may be imposed on "responsible parties" for all containment and cleanup costs and certain other damages arising from a release, including, but not limited to, the costs of responding to a release of oil to surface waters and natural resource damages resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States. A "responsible party" includes the owner or operator of an onshore facility. The OPA establishes a liability limit for onshore facilities, but these liability limits may not apply if: a spill is caused by a party's gross negligence or willful misconduct; the spill resulted from violation of a federal safety, construction or operating regulation; or a party fails to report a spill or to cooperate fully in a cleanup. We are also subject to analogous state statutes that impose liabilities with respect to oil spills. For example, the California Department of Fish and Wildlife's Office of Oil Spill Prevention and Response has adopted oil-spill prevention regulations that overlap with federal regulations.

We also generate solid wastes, including hazardous wastes, which are subject to the requirements of the Resource Conservation and Recovery Act, as amended ("RCRA"), and comparable state statutes. Although RCRA regulates both solid and hazardous wastes, it imposes stringent requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. Certain petroleum production wastes are excluded from RCRA's hazardous waste regulations. These wastes, instead, are regulated under RCRA's less stringent solid waste provisions, state laws or other federal laws. It is possible that these wastes, which could include wastes currently generated during our operations, could be designated as "hazardous wastes" in the future and, therefore, be subject to more rigorous and costly disposal requirements. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain oil and gas exploration and production wastes as "hazardous wastes." Also, in December 2016, the EPA entered into a consent decree requiring it to review its regulation of oil and gas waste. In April 2019, the EPA determined that revisions to the RCRA regulations were not required, concluding that any adverse effects related to oil and gas waste are more appropriately and readily addressed within the framework of existing state regulatory programs. However, any such changes to state programs could result in an increase in our costs to manage and dispose of oil and gas waste, which could have a material adverse effect on our maintenance capital expenditures and operating expenses.

It is possible that our oil and natural gas operations may require us to manage naturally occurring radioactive materials ("NORM"). NORM is present in varying concentrations in sub-surface formations, including hydrocarbon reservoirs, and may become concentrated in scale, film and sludge in equipment that comes into contact with crude oil and natural gas production and processing streams. Some states have enacted regulations governing the handling, treatment, storage and disposal of NORM.

Administrative, civil and criminal penalties can be imposed for failure to comply with hazardous substance and waste handling requirements. We believe that we are in substantial compliance with the requirements of CERCLA, OPA, RCRA, and other applicable federal and related state and local laws and regulations, and that we hold all necessary and up-to-date permits, registrations and other authorizations required under such laws and regulations. Although we believe that the current costs of managing our hazardous substances and wastes as they are presently classified are reflected in our budget, any legislative or regulatory reclassification of oil and natural gas exploration and production wastes could increase our costs to manage and dispose of such wastes.

Water Discharges

The Federal Water Pollution Control Act (the “Clean Water Act”), the Safe Drinking Water Act (“SDWA”), the OPA and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including oil and hazardous substances, into navigable waters of the United States, as well as state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. These laws and regulations also prohibit certain activity in wetlands unless authorized by a permit issued by the U.S. Army Corps of Engineers (“Corps”). In June 2015, the EPA and the Corps issued a rule to revise the definition of “waters of the United States” (“WOTUS”) for all Clean Water Act programs, which never took effect before being replaced by the Navigable Waters Protection Rule (“NWPR”) in December 2019. In addition, in an April 2020 decision further defining the scope of the CWA, the U.S. Supreme Court held that, in certain cases, discharges from a point source to groundwater could fall within the scope of the CWA and require a permit. The Court rejected the EPA and Corps’ assertion that groundwater should be totally excluded from the CWA. To the extent a new rule or further litigation expands the scope of the Clean Water Act’s jurisdiction or impacts available agency resources, the Company could face increased costs and/or delays with respect to obtaining permits for dredge and fill activities in wetland areas.

The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges. Costs may be associated with the treatment of storm water or developing and implementing storm water pollution prevention plans, as well as for monitoring and sampling the storm water runoff from certain of our facilities. Some states also maintain groundwater protection programs that require permits or specify other requirements for discharges or operations that may impact groundwater conditions. These same regulatory programs may also limit the total volume of water that can be discharged, hence limiting the rate of development and requiring us to incur compliance costs. Additionally, we are required to develop and implement spill prevention, control and countermeasure plans, in connection with on-site storage of significant quantities of oil.

These laws and any implementing regulations provide for administrative, civil and criminal penalties for any unauthorized discharges of oil and other substances in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages. Additionally, obtaining permits has the potential to delay the development of natural gas and oil projects. We maintain all required discharge permits necessary to conduct our operations and we believe we are in substantial compliance with their terms.

In addition, in some instances, the operation of underground injection wells for the disposal of wastewater has been alleged to cause earthquakes. For example, the EPA released a report with findings and recommendations related to public concern about induced seismic activity from disposal wells. The report recommended strategies for managing and minimizing the potential for significant injection-induced seismic events. In some jurisdictions, such issues have led to orders prohibiting continued injection or the suspension of drilling in certain wells identified as possible sources of seismic activity or resulted in stricter regulatory requirements relating to the location and operation of underground injection wells. Such issues have also led to lawsuits by private parties alleging damages relating to induced seismicity. For example, the Railroad Commission of Texas (the "Commission") requires applicants for new disposal wells that will receive non-hazardous produced water and hydraulic fracturing flowback fluid to conduct seismic activity searches utilizing the U.S. Geological Survey, which are intended to determine the potential for earthquakes within a circular area of 100 square miles around a proposed, new disposal well. The Commission is authorized to modify, suspend or terminate a disposal well permit if scientific data indicates a disposal well is likely to contribute to seismic activity. The Commission is also considering new restrictions that could limit the volume and pressure of produced water injected into disposal wells. Additionally, we conduct oil and gas drilling and production operations in the Mississippian Lime formation in Oklahoma, a high-water play, which requires us to dispose of large volumes of saltwater generated as part of our operations. The Oklahoma Geological Survey attributed an increase in seismic activity in Oklahoma to saltwater disposal wells in the Arbuckle formation and, the Oklahoma Corporation Commission ("OCC"), whose Oil and Gas Conservation Division regulates oil and gas operations in Oklahoma, issued regulations targeting saltwater disposal activities in certain areas of interest within the Arbuckle formation. The regulations include operational requirements (i.e., mechanical integrity testing of wells permitted for disposal of 20,000 or more barrels of water per day, daily monitoring and recording of well pressure and discharge volume), as well as orders to shut-in wells, reduce well depths, or decrease disposal volumes. Under these regulations, in 2016 and 2017, the OCC ordered us to limit the volume of saltwater disposed of in saltwater disposal wells in the Arbuckle formation, and it established caps for ten of our saltwater disposal wells in February 2017, which caps are still in place. To ensure that we had an adequate number of wells for disposal, we secured permits for additional saltwater disposal wells outside of the Arbuckle formation. We timely satisfied all OCC saltwater disposal requirements, while maintaining our production base without any negative material impact. However, any future orders or regulations addressing concerns about seismic activity from well injection in jurisdictions where we operate could affect or curtail our operations.

Hydraulic Fracturing

We use hydraulic fracturing extensively in our onshore operations, but not our offshore operations. Hydraulic fracturing is an essential and common practice in the oil and gas industry used to stimulate production of natural gas and/or oil from low permeability subsurface rock formations. Hydraulic fracturing involves using water, sand and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow the flow of hydrocarbons into the wellbore. While hydraulic fracturing has historically been regulated by state oil and natural gas commissions, the practice has become increasingly controversial in certain parts of the country, resulting in increased scrutiny and regulation. For example, the EPA's wastewater pretreatment standards prohibit onshore unconventional oil and natural gas extraction facilities from sending wastewater to publicly-owned treatment works. This restriction of disposal options for hydraulic fracturing waste and other changes to environmental requirements may result in increased costs.

In addition, in March 2015, the BLM published a final rule governing hydraulic fracturing on federal and Indian lands. The rule required public disclosure of chemicals used in hydraulic fracturing, implementation of a casing and cementing program, management of recovered fluids and submission to the BLM of detailed information about the proposed operation, including wellbore geology, the location of faults and fractures and the depths of all usable water. Following years of litigation, the BLM rescinded the rule in December 2017. However, several environmental groups and states have challenged the BLM's rescission of the rule in ongoing litigation.

Several states have also adopted, or are considering adopting, regulations requiring the disclosure of the chemicals used in hydraulic fracturing and/or otherwise imposing additional requirements for hydraulic fracturing activities. For example, Oklahoma requires oil and gas producers to report the chemicals they use in hydraulic fracturing to FracFocus.org, a national hydraulic fracturing chemical registry, or to the OCC, which will convey the information to FracFocus.org. The Louisiana Department of Natural Resources has adopted rules requiring the public disclosure of the composition and volume of fracturing fluids used in hydraulic fracturing operations. Also, Texas requires oil and natural gas operators to disclose to the Commission and the public the chemicals used in the hydraulic fracturing process, as well as the total volume of water used. Texas has also imposed requirements for drilling, putting pipe down and cementing wells, and testing and reporting requirements.

Certain governmental reviews have been conducted that focus on environmental aspects of hydraulic fracturing practices, which could lead to increased regulation. For example, the EPA issued a report examining the potential for hydraulic fracturing activities to impact drinking water resources, finding that, under some circumstances, the use of water in hydraulic fracturing activities can impact drinking water resources. The EPA has also issued a report on onshore conventional and unconventional oil and gas extraction wastewater management, and conducted a study of private wastewater treatment facilities, also known as centralized waste treatment facilities, accepting oil and gas extraction wastewater. Other governmental agencies, including the U.S. Department of Energy, the U.S. Geological Survey, and the U.S. Government Accountability Office, have evaluated various other aspects of hydraulic fracturing. In addition, as discussed above, BOEM and BSEE completed a study regarding the potential environmental impacts of well-stimulation practices on the Pacific OCS. These studies could spur initiatives to further regulate hydraulic fracturing and could ultimately make it more difficult or costly for us to perform fracturing and increase our costs of compliance and doing business.

Additionally, a number of lawsuits and enforcement actions have been initiated across the country, alleging that hydraulic fracturing practices have induced seismic activity and adversely impacted drinking water supplies, use of surface water, and the environment generally. Several states and municipalities have adopted, or are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances. We believe that we follow standard industry practices and legal requirements applicable to our hydraulic fracturing activities. Nonetheless, in the event of new or more stringent federal, state or local legal restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling of wells. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater or otherwise have negative impacts.

In addition, if hydraulic fracturing is further regulated at the federal, state or local level, our fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. For example, the U.S. Congress has from time to time considered legislation to amend the SDWA, including legislation that would repeal the exemption for hydraulic fracturing from the definition of “underground injection” and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process. Such legislative changes could cause us to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the impact on our business of newly enacted or potential federal or state legislation governing hydraulic fracturing, and any of the above risks could impair our ability to manage our business and have a material adverse effect on our operations, cash flows and financial position.

Air Emissions

The federal Clean Air Act, as amended (“CAA”), and comparable state laws restrict the emission of air pollutants from many sources, including compressor stations, through the issuance of permits and the imposition of other requirements. The South Coast Air Quality Management District (“SCAQMD”) is a regulatory subdivision of the State of California and is responsible for air pollution control from stationary sources within Orange County and designated portions of Los Angeles, Riverside, and San Bernardino Counties. Our Beta Properties and associated facilities are subject to regulation by the SCAQMD. Federal, SCAQMD, and other state laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants.

The EPA has developed, and continues to develop, stringent regulations governing emissions of air pollutants at specified sources. New facilities may be required to obtain permits before work can begin, and modified and existing facilities may be required to obtain additional permits. In June 2016, the EPA finalized regulations establishing New Source Performance Standards (NSPS), known as Subpart OOOOa, for methane and volatile organic compounds ("VOC") from new and modified oil and natural gas production and natural gas processing and transmission facilities. In September 2020, the EPA finalized two sets of amendments to the 2016 Subpart OOOOa standards. The first, known as the 2020 Technical Rule, reduced the 2016 rule's fugitive emissions monitoring requirements and expanded exceptions to pneumatic pump requirements, among other changes. The second, known as the 2020 Policy Rule, rescinded the methane-specific requirements for certain oil and natural gas sources in the production and processing segments. On January 20, 2021, President Biden issued an Executive Order directing the EPA to rescind the 2020 Technical Rule by September 2021 and consider revising the 2020 Policy Rule. On June 30, 2021, President Biden signed a Congressional Review Act ("CRA") resolution passed by Congress that revoked the 2020 Policy Rule. The CRA did not address the 2020 Technical Rule.

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

Similarly, in September 2018, the BLM issued a rule that relaxed or rescinded certain requirements of the agency's 2016 Waste Prevention Rule, which aimed to reduce methane emissions from venting, flaring, and leaks during oil and gas operations on public lands; both the 2016 rule and its 2018 rescission were invalidated in federal district court. Environmental groups appealed the invalidation of the 2016 rule to the U.S. Court of Appeals for the Tenth Circuit, which is stayed pending a review of the rule by BLM. As a result of these regulatory changes, the scope of any final methane regulations or the costs for complying with the federal methane regulations are uncertain. However, any future changes to the regulations governing methane emissions, and other air quality programs, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements, or utilize specific equipment or technologies to control emissions. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs and could adversely impact our business.

We may be required to incur certain capital expenditures in the next few years for air pollution control equipment in connection with maintaining or obtaining operating permits addressing air emission related issues, which may have a material adverse effect on our operations. Obtaining permits also has the potential to delay the development of oil and natural gas projects and increase our costs of development, which costs could be significant. We believe that we currently are in substantial compliance with all air emissions regulations and that we hold all necessary and valid construction and operating permits for our current operations.

Regulation of "Greenhouse Gas" Emissions

In December 2015, the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change resulted in nearly 200 countries, including the United States, coming together to develop the Paris Agreement, which calls for the parties to undertake "ambitious efforts" to limit the average global temperature. Although the agreement does not create any binding obligations for nations to limit their greenhouse gas emissions, it does include pledges to voluntarily limit or reduce future emissions. On June 1, 2017, President Trump announced that the U.S. would withdraw from the Paris Agreement and completed the process of withdrawing on November 4, 2020. However, on January 20, 2021, President Biden issued written notification to the United Nations of the United States' intention to rejoin the Paris Agreement, which became effective on February 19, 2021. In addition, in September 2021, President Biden publicly announced the Global Methane Pledge, a pact that aims to reduce global methane emissions at least 30% below 2020 levels by 2030. Since its formal launch at the United Nations Climate Change Conference ("COP26"), over 100 countries have joined the pledge.

While Congress has, from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. However, the United States House of Representatives passed H.R. 5376, known as the Build Back Better Act on November 3, 2021. The House version of the bill targets methane from oil and gas sources by proposing to implement fees for excess methane leaking from wells, storage sites and pipelines as well as fees for new producing and non-producing oil and gas leases and off-shore pipelines. It is included whether the Build Back Better Act would be passed in its current form by the United States Senate. In the absence of such federal climate legislation, a number of states have taken legal measures to reduce emissions of GHGs, including through the planned development of GHGs emission inventories and/or regional GHGs cap and trade programs.

The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas we produce. For example, any GHG regulation could increase our costs of compliance by potentially delaying the receipt of permits and other regulatory approvals; requiring us to monitor emissions, install additional equipment or modify facilities to reduce GHG and other emissions; purchase emission credits; and utilize electric driven compression at facilities to obtain regulatory permits and approvals in a timely manner. Such climate change regulatory and legislative initiatives could have a material adverse effect on our business, financial condition and results of operations.

While we are subject to certain federal GHG monitoring and reporting requirements, our operations are not adversely impacted by existing federal, state and local climate change initiatives and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing GHG emissions would impact our business. For example, the California Legislature is considering a bill that would require corporations that conduct business in California to report on their Scope 1, 2, and 3 emission using the standards and guidance set out under the Greenhouse Gas Protocol and obtain third-party auditor verification of their reports. The California State Senate passed the bill in January 2022 and ordered the bill to the state assembly for consideration.

In addition, claims have been made against certain energy companies alleging that GHG emissions from oil and natural gas operations constitute a public nuisance or have caused other redressable injuries under federal and/or state common law. While our business is not a party to any such litigation, we could be named in actions making similar allegations. An unfavorable ruling in any such case could adversely impact our business, financial condition and results of operations.

Moreover, any legislation or regulatory programs to reduce GHG emissions could increase the cost of consumption, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations. Incentives to conserve energy or use alternative energy sources as a means of addressing climate change could also reduce demand for the oil and natural gas we produce. In addition, parties concerned about the potential effects of climate change have directed their attention at sources of funding for energy companies, which has resulted in certain financial institutions, funds and other sources of capital, restricting or eliminating their investment in oil and natural gas activities. Finally, it should be noted that most scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our development and production operations, as well as potentially increased costs for insurance coverages in the aftermath of such effects.

National Environmental Policy Act

Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the U.S. Departments of the Interior and Agriculture, to evaluate major federal actions having the potential to significantly impact the human environment. In the course of such evaluations, an agency evaluates the potential direct, indirect and cumulative impacts of a proposed project. If the proposed impacts are considered significant, the agency will prepare a detailed environmental impact statement that is made available for public review and comment. In July 2020, the White House's Council on Environmental Quality published a final rule to amend the NEPA implementing regulations intended to streamline the environmental review process, including shortening the time for review as well as eliminating the requirement to evaluate cumulative impacts. The new regulations are subject to ongoing litigation, which has been stayed pending an ongoing review of the 2020 rule. On October 6, 2021, the Council on Environmental Quality announced its Phase 1 rule, the first of two planned rules to roll back the 2020 rule. All of our current development and production activities, as well as proposed development plans, on federal lands, including those in the Pacific Ocean, require governmental permits that are subject to the requirements of NEPA. This environmental review process has the potential to delay the development of oil and natural gas projects. Authorizations under NEPA also are subject to protest, appeal or litigation, which can delay or halt projects.

Endangered Species Act and Migratory Bird Treaty Act

The federal ESA and analogous state statutes restrict activities that may adversely affect endangered and threatened species or their habitat. In August 2019, the U.S. Fish and Wildlife Service (the "FWS") and National Marine Fisheries Service ("NMFS") issued three rules amending the implementation of the ESA regulations revising, among other things, the process for listing species and designating critical habitats. A coalition of states and environmental groups have challenged these rules, and the litigation remains pending. In addition, on December 18, 2020, the FWS amended its regulations governing critical habitat designations, the amended regulations are subject to ongoing litigation. In June 2021, FWS and NMFS announced plans to begin rulemaking processes to rescind these rules. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act ("MBTA"), which makes it illegal to, among other things, hunt, capture, kill, possess, sell, or purchase migratory birds, nests, or eggs without a permit. This prohibition covers most bird species in the U.S. On January 7, 2021, the Department of the Interior finalized a rule limiting the application of the MBTA. However, the Department of the Interior revoked the rule in October 2021 and issued an advanced notice of proposed rulemaking seeking comment on the Department's plan to develop regulations that authorize incidental take under certain prescribed conditions. Future implementation of the rules implementing the ESA and the MBTA are uncertain. The designation of previously unidentified endangered or threatened species in areas where we operate could cause us to incur additional costs or become subject to operating delays, restrictions or bans. Numerous species have been listed or proposed for protected status in areas in which we currently, or could in the future, undertake operations. The presence of protected species in areas where we operate could impair our ability to timely complete or carry out those operations, lose leaseholds as we may not be permitted to timely commence drilling operations, cause us to incur increased costs arising from species protection measures, and consequently, adversely affect our results of operations and financial position.

Occupational Safety and Health Act

We are also subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA's hazard communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. Other OSHA standards regulate specific worker safety aspects of our operations. For example, under a new OSHA standard limiting respirable silica exposure, the oil and gas industry was required to implement engineering controls and work practices to limit exposures below the new limits by June 2021. Failure to comply with OSHA requirements can lead to the imposition of penalties. We believe that our operations are in substantial compliance with the OSHA requirements.

Other Regulation of the Oil and Natural Gas Industry

The oil and natural gas industry is extensively regulated by numerous federal, state and local authorities. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden on our assets. Additionally, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations that are binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the oil and natural gas industry with similar types, quantities and locations of production.

Legislation continues to be introduced in Congress, and the development of regulations continues in the U.S. Department of Homeland Security and other agencies concerning the security of industrial facilities, including oil and natural gas facilities. Our operations may be subject to such laws and regulations. Presently, it is not possible to accurately estimate the costs we could incur to comply with any such facility security laws or regulations, but such expenditures could be substantial.

Drilling and Production

Our operations are subject to various types of regulation at federal, state and local levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most states, and some counties and municipalities, in which we operate also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;

- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells;
- transportation of materials and equipment to and from our well sites and facilities;
- transportation and disposal of produced fluids and natural gas; and
- notice to surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration, while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and NGLs within its jurisdiction.

Sale and Transportation of Gas and Oil

The Federal Energy Regulatory Commission ("FERC") has jurisdiction over the construction and operations of interstate gas pipeline facilities and the rates, terms and conditions of service under which companies provide interstate transportation of gas, oil and other liquids by pipeline. Although the FERC does not have jurisdiction over the production of gas, the FERC exercises regulatory authority over wholesale sales of gas in interstate commerce through the issuance of blanket marketing certificates that authorize the wholesale sale of gas at market rates and the imposition of a code of conduct on blanket marketing certificate holders that regulate certain affiliate interactions. The FERC does not regulate the sale of oil or petroleum products or the construction of oil or other liquids pipelines. The FERC also has oversight of the performance of wholesale natural gas markets, including the authority to facilitate price transparency and to prevent market manipulation. In furtherance of this authority, the FERC imposed an annual reporting requirement on all industry participants, including otherwise non-jurisdictional entities, engaged in wholesale physical natural gas sales and purchases in excess of a minimum level. These agency actions have been intended to foster increased competition within all phases of the gas industry. To date, the FERC's pro-competition policies have not materially affected our business or operations. It is unclear what impact, if any, future rules or increased competition within the gas industry will have on our gas sales efforts.

The FERC and other federal agencies, the U.S. Congress or state legislative bodies and regulatory agencies may consider additional proposals or proceedings that might affect the gas or oil industries. We cannot predict when or if these proposals will become effective or any effect they may have on our operations. We do not believe, however, that any such proposal will affect us any differently than it would affect other gas or oil producers with which we compete.

The Beta Properties include the San Pedro Bay Pipeline Company, which owns and operates an offshore crude oil pipeline. This pipeline is subject to regulation by the FERC under the Interstate Commerce Act and the Energy Policy Act of 1992. Tariff rates for liquids pipelines, which include both crude oil pipelines and refined products pipelines, must be just and reasonable and not unduly discriminatory. FERC regulations require that interstate oil pipeline transportation rates and terms of service be filed with the FERC and posted publicly. The FERC has established a formulaic methodology for oil and liquids pipelines to change their rates within prescribed ceiling levels that are tied to an inflation index. The FERC reviews the formula every five years. Effective July 1, 2016, the current index for the five-year period ending July 2021 is the producer price index for finished goods plus an adjustment factor of 1.23 percent. The San Pedro Bay Pipeline Company uses the indexing methodology to change its rates.

The Outer Continental Shelf Lands Act requires that all pipelines operating on or across the OCS provide open access, non-discriminatory transportation service. BOEM/BSEE has established formal and informal complaint procedures for shippers that believe they have been denied open and non-discriminatory access to transportation on the OCS.

The U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration ("PHMSA") regulates the safety of all pipeline transportation in or affecting interstate or foreign commerce, including pipeline facilities on the OCS. The San Pedro Bay pipeline is subject to regulation by the PHMSA. In recent years, PHMSA has been active in proposing and finalizing additional regulations for natural gas and hazardous liquids pipelines. For example, in January 2017, PHMSA finalized new regulations for hazardous liquid pipelines that significantly extend and expand the reach of certain PHMSA integrity management requirements (i.e., periodic assessments, repairs and leak detection), regardless of the pipeline's proximity to a high consequence area ("HCA"). The final rule also requires all pipelines in or affecting an HCA to be capable of accommodating in-line inspection tools within the next 20 years. In addition, the final rule extends annual and accident reporting requirements to gravity lines and all gathering lines and also imposes inspection requirements on pipelines in areas affected by extreme weather events and natural disasters, such as hurricanes, landslides, floods, earthquakes, or other similar events that are likely to damage infrastructure. In addition, in April 2016, PHMSA proposed a rule regarding the safety of natural gas transmission pipelines and gas gathering pipelines. In October 2019, PHMSA issued a final rule on the natural gas transmission lines portion of the April 2016 rulemaking, and in November 2021 PHMSA issued a final rule on the gathering lines portion of the April 2016 rulemaking. Under the new final rule, operators of onshore natural gas gathering pipelines that were previously excluded from certain PHMSA regulations face additional testing, safety and reporting requirements or may be forced to reduce their allowable operating pressures, which would reduce the amount of capacity available to the Company. Certain reporting requirements arising from the new PHMSA rule take effect in May 2022, with additional requirements taking effect later in 2022 and 2023.

Moreover, effective April 2017, the PHMSA adopted new rules increasing the maximum administrative civil penalties for violation of the pipeline safety laws and regulations. PHMSA updates the maximum administrative civil penalties each year to account for inflation, and as of January 2021, the penalty limits are up to $225,134 per violation per day and up to $2,251,334 for a related series of violations. The PHMSA has also issued a final rule applying safety regulations to certain rural low-stress hazardous liquid pipelines that were not covered previously by some of its safety regulations. Federal and state legislative and regulatory initiatives relating to pipeline safety that require the use of new or more stringent safety controls or result in more stringent enforcement of applicable legal requirements could subject us to increased capital costs, operational delays and costs of operation.

Anti-Market Manipulation Laws and Regulations

The FERC, with respect to the purchase or sale of natural gas or the purchase or sale of transmission or transportation services subject to FERC jurisdiction and the Federal Trade Commission with respect to petroleum and petroleum products, operating under various statutes, have each adopted anti-market manipulation regulations, which prohibit, among other things, fraud and price manipulation in the respective markets. These agencies hold substantial enforcement authority, including the ability to assess substantial civil penalties, to order repayment or disgorgement of profits and to recommend criminal penalties. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third-party damage claims by, among others, sellers, royalty owners and taxing authorities.

Derivatives Regulation

Comprehensive financial reform legislation was signed into law by the President on July 21, 2010 ("Dodd-Frank Act"). This legislation called for the Commodities Futures Trading Commission ("CFTC") to regulate certain markets for derivative products, including over-the-counter derivatives. The CFTC has issued several new relevant regulations and rulemakings to implement the Dodd-Frank Act, the mandate to cause significant portions of derivatives markets to clear through clearinghouses, along with other mandated changes. While some of these rules have been finalized, some have not. As a result, the final form and timing of the implementation of the new regulatory regime affecting commodity derivatives remains uncertain.

In particular, on October 18, 2011, the CFTC adopted final rules under the Dodd-Frank Act establishing position limits for certain energy commodity futures and options contracts and economically equivalent swaps, futures and options. The CFTC's final rules were challenged in court by two industry associations and were vacated and remanded by a federal district court. Subsequently, the CFTC proposed new rules in November 2013 and December 2016. In January 2020, the CFTC withdrew the 2013 and 2016 proposals and issued a new proposed rule, which includes limits on positions in (1) certain "Core Referenced Futures Contracts," including contracts for several energy commodities; (2) futures and options on futures that are directly or indirectly linked to the price of a Core Referenced Futures Contract, or to the same commodity for delivery at the same location as specified in that Core Referenced Futures Contract; and (3) economically equivalent swaps. The proposal also includes exemptions from position limits for bona fide hedging activities. The proposal is not yet final, and it remains subject to public comment and subsequent revision by the CFTC. Consequently, the impact of the proposed rule on the Company and its counterparties is uncertain at this time.

The Dodd-Frank Act and new, related regulations may prompt counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may become less predictable, which could adversely affect our ability to plan for and fund capital expenditures and to generate sufficient cash flow to pay quarterly distributions at current levels or at all. Our revenues could be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material, adverse effect on us, our financial condition and our results of operations. Our use of derivative financial instruments does not eliminate our exposure to fluctuations in commodity prices and interest rates and has in the past and could in the future result in financial losses or reduce our income.

Our sales of oil and natural gas are also subject to anti-manipulation and anti-disruptive practices authority under (i) the Commodity Exchange Act ("CEA"), as amended by the Dodd-Frank Act, and regulations promulgated thereunder by the CFTC, and (ii) the Energy Independence and Security Act of 2007 ("EISA") and regulations promulgated thereunder by the FTC. The CEA, as amended by the Dodd-Frank Act, prohibits any person from using or employing any manipulative or deceptive device in connection with any swap, or a contract for sale of any commodity, or for future delivery on such commodity, in contravention of the CFTC's rules and regulations. It also prohibits knowingly delivering or causing to be delivered false, misleading or inaccurate reports concerning market information or conditions that affect or tend to affect the price of any commodity. The FTC's Petroleum Market Manipulation Rule, issued pursuant to EISA, prohibits fraudulent or deceptive conduct (including false or misleading statements of material fact) in connection with wholesale purchases or sales of crude oil or refined petroleum products. Under both the CEA and the EISA, fines for violations can be up to $1,000,000 per day per violation (subject to adjustment for inflation) and certain knowing or willful violations may also lead to a felony conviction.

Additional proposals and proceedings that may affect the crude oil and natural gas industry are pending before the U.S. Congress, federal agencies and the courts. The Company cannot predict the ultimate impact these proposals may have on its crude oil and natural gas operations, but the Company does not expect any such action to affect the Company differently than it will affect other gas or oil producers with which we compete.

State Regulation

Various states regulate the drilling for, and the production, gathering and sale of, oil and natural gas, including imposing severance taxes and requirements for obtaining drilling permits. For example, the baseline Texas severance tax on oil and gas is 4.6% of the market value of oil produced and 7.5% of the market value of gas produced and saved. A number of exemptions from or reductions of the severance tax on oil and gas production are provided by the State of Texas which effectively lowers the cost of production. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of natural gas resources. States may regulate rates of production and may establish maximum daily production allowable from natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but there can be no assurance that they will not do so in the future. The effect of these regulations may be to limit the amount of oil and natural gas that may be produced from our wells and to limit the number of wells or locations we can drill.

The petroleum industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to resource conservation and equal employment opportunity. We do not believe that compliance with these laws will have a material adverse effect on us.

Human Capital

Overview

At December 31, 2021, the Company had 210 employees, none of whom were represented by labor unions or covered by any collective bargaining agreement. We strive to create a high-performing culture and positive work environment that allows us to attract and retain a diverse group of talented individuals who can foster the Company's success. To attract and retain top talent, our human resources programs are designed to reward and incentivize our employees through competitive compensation practices, our commitment to employee health and safety, training and talent development and our commitment to diversity and inclusion.

Safety

Safety is our highest priority, and we are dedicated to the well-being of our employees, contractors, business partners, stakeholders and the environment. We promote safety with a robust health and safety program, which includes employee orientation and training, contractor management, risk assessments, hazard identification and mitigation, audits, incident reporting and investigation, and corrective and preventative action development.

In addition, we employ environmental, health and safety personnel at each of our asset locations, who provide in-person safety training and regular safety meetings. We also utilize learning management software to provide safety training on a variety of topics, and we contract with third-party technical experts, as needed, to facilitate training on specialized topics that are unique to each of our areas of operation.

Compensation

We operate in a highly competitive environment and have designed our compensation program to attract, retain and motivate talented and experienced individuals. Our compensation philosophy is designed to align our workforce's interests with those of our stakeholders and to reward them for achieving the Company's business and strategic objectives and driving shareholder value. We consider competitive market compensation paid by our peers and other companies comparable to us in size, geographic location and operations in order to ensure compensation remains competitive and fulfills our goal of recruiting and retaining talented employees.

Training and Development

We are committed to the training and development of our employees. Employees are regularly provided training opportunities to develop skills in leadership, safety, and technical acumen, which bolsters our efforts in conducting business in a safe manner and with high ethical standards. Further, we believe that supporting our employees in achieving their career and development goals is a key element of our approach to attracting and retaining top talent. We encourage our employees to advance their knowledge and skills and to network with other professionals in order to pursue career advancement and potential future opportunities with the Company. Our employees are able to attend training seminars and off-site workshops or to join professional associations that will enable them to remain up-to-date on the latest changes and best practices in their respective fields.

Diversity and Inclusion

We are committed to providing a diverse and inclusive workplace and career development opportunities to attract and retain talented employees. We recognize that a diverse workforce provides the opportunity to obtain unique perspectives, experiences, ideas, and solutions to help our business succeed. To that end, it is our policy to prohibit discrimination and harassment of any type and afford equal employment opportunities to employees and applicants without regard to race, color, religion, sex, national origin, age, disability, genetic information, veteran status, or any other basis protected by federal, state or local law. Further, it is our policy to forbid retaliation against any individual who reports, claims, or makes a charge of discrimination or harassment, fraud, unethical conduct, or a violation of our Company policies. To sustain and promote an inclusive culture, we maintain a robust compliance program rooted in our Code of Business Conduct and Ethics and other Company policies, which provide policies and guidance on non-discrimination, anti-harassment, and equal employment opportunities. We require all employees to complete periodic training sessions on various aspects of our corporate policies through an annual acknowledgment and certification process.

Health and Wellness

We support our employees and their families by offering a robust package of health and welfare benefits, medical, dental, and vision insurance plans for employees and their families, life insurance and long-term disability plans, paid time off for holidays, vacation, sick leave, and other personal leave, and health and dependent care savings accounts. We also provide our employees with a 401(k) plan that includes a competitive company match, and employees have access to a variety of resources and services to help them plan for retirement.

In addition to these programs, we have several other programs designed to further promote the health and wellness of our employees, as well as an employee assistance program that offers counseling and referral services for a broad range of personal and family situations.

In response to the COVID-19 pandemic, commencing in the first quarter of 2020, we implemented proactive measures to protect the health and safety of our employees. These measures have included implementation of a COVID-19 leave program to allow employees to take time off when they or their family members contract COVID-19, implementation of health screenings, COVID-19 testing for our offshore workforce, allowing employees to work remotely to reduce the number of employees on site in our field areas to comply with social distancing guidelines, maintaining social distancing policies, requiring the use of masks in compliance with governmental mandates, frequently and extensively disinfecting common areas, performing contact tracing protocols, if and when necessary, and implementing quarantine requirements, among other things. We are committed to maintaining best practices with our COVID-19 response protocols and will continue to work under the guidance of public health officials to ensure a safe workplace as long as COVID-19 remains a threat to our employees and communities.

Offices

Our principal executive office is located at 500 Dallas Street, Suite 1700, Houston, Texas 77002. Our main telephone number is (832) 219-9001.

Available Information

Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8–K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act are made available free of charge on our website at www.amplifyenergy.com as soon as reasonably practicable after these reports have been electronically filed with, or furnished to, the SEC. Our website also includes our Code of Business Conduct and Ethics, Corporate Governance Guidelines and the charters of our audit committee, compensation committee and nominating & governance committee. The information contained on, or connected to, our website is not incorporated by reference into this Form 10-K and should not be considered part of this or any other report that we file with or furnish to the SEC.

The SEC maintains a website that contains reports, proxy and information statements, and other information regarding the Company at www.sec.gov.

ITEM 1A. RISK FACTORS

Our business and operations are subject to many risks. The risks described below, in addition to the risks described in "Item 1. Business" of this Annual Report, may not be the only risks we face, as our business and operations may also be subject to risks that we do not yet know of, or that we currently believe are immaterial. You should carefully consider the following risk factors together with all of the other information included in this Annual Report, including the financial statements and related notes, when deciding to invest in us. You should be aware that the occurrence of any of the events described in this Risk Factors section and elsewhere in this Annual Report could have a material adverse effect on our business, financial position, results of operations and cash flows and the trading price of our securities could decline and you could lose all or part of your investment.

Risks Related to the Southern California Pipeline Incident

Significant uncertainties exist regarding the extent and timing of costs and liabilities relating to the Incident, and potential changes in the regulatory and operating environment in which we operate resulting from the Incident may increase the risks to which we are exposed. The duration of such uncertainties may exist for a significant period, and such risks may have a material adverse impact on our business, results of operations and financial condition and the implementation of our strategic agenda. Furthermore, the risks associated with the Incident may heighten the consequences of other risks to which we are exposed, including with respect to access to financing and financial assurance.

Our assumptions and estimates regarding the total aggregate costs associated with the Incident may be inaccurate, which could materially and adversely affect our business, results of operations and financial condition

As of February 2, 2022, the Unified Command announced that response and monitoring efforts have officially concluded for the Beta Incident, and Unified Command would stand down as of such date. We currently estimate that the total costs we have incurred or will incur with respect to the Incident related to (i) actual and projected response and remediation expenses incurred under the direction of the Unified Command and (ii) estimates for certain legal fees to be approximately $90.0 million to $110.0 million. These estimates consider currently available facts and presently enacted laws and regulations. We have made assumptions regarding (i) the probable and estimable amounts expected to be settled with certain vendors for response and remediation expenses and (ii) the resolution of certain third-party claims, excluding claims with respect to losses, which are not probable and reasonably estimable, and (iii) future claims and lawsuits. Our estimates do not include (i) the nature, extent and cost of future legal services that will be required in connection with all lawsuits, claims and other matters requiring legal or expert advice associated with the Incident, (ii) any lost revenue associated with the suspension of operations at Beta, (iii) any liabilities or costs that are not reasonably estimable at this time or that relate to contingencies where we currently regard the likelihood of loss as being only reasonably possible or remote and (iv) the future costs associated with the permanent repair of the pipeline and the restart of Beta operations. We believe we have accrued adequate amounts for all probable and reasonably estimable costs; however, this estimate is subject to uncertainties associated with the assumptions that we have made. For example, settlements with vendors for response and remediation expenses could turn out to be significantly higher or lower than we have estimated. Accordingly, our assumptions and estimates may change in future periods based on future events and total costs may materially increase; therefore, we can provide no assurance that we will not have to accrue significant additional costs in future periods with respect to the Incident.

We are subject to significant litigation and enforcement risk as a result of the Incident.

Under the OPA 90, the Company's pipeline was designated by the United States Coast Guard as the source of the oil discharge. Therefore, the Company is financially responsible for remediation for certain costs and economic damages as provided in OPA 90. The Company is currently processing covered claims under OPA 90 as expeditiously as possible. At this time, it is not possible to estimate the total number of future claims or the full extent of compensable damages arising from the Incident.

In addition, we and certain of our subsidiaries have been named as defendants in approximately 14 putative class action lawsuits in the United States District Court for the Central District of California. The putative class actions have been consolidated into a single consolidated action in the United States District Court for the Central District of California. In the consolidated action, Plaintiffs filed an amended class action complaint on January 28, 2022. The amended complaint asserted claims against us and MSC Mediterranean Shipping Company, Dordellas Finance Corp., Costamare Shipping Co. S.A., and Capetanissa Maritime Corporation of Liberia. Resolution of the consolidated case may take considerable time, and it is not possible at this time to estimate our potential liability resulting from these actions.

Federal, state and municipal authorities may also take enforcement action against us as a result of the Incident. To date, the U.S. Coast Guard, the U.S. Bureau of Ocean Energy Management, the U.S. Department of Justice, the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration, the U.S. Department of the Interior Bureau of Safety and Environmental Enforcement, the California Department of Justice, the Orange County District Attorney, the Los Angeles County District Attorney and the California Department of Fish & Wildlife are conducting investigations or examinations of the Incident. Other federal agencies may or have commenced investigations and proceedings, and federal agencies such as the U.S. Environmental Protection Agency may initiate enforcement actions seeking penalties and other relief under the Clean Water Act and other statutes. The outcomes of these investigations and the nature of any remedies pursued will depend on the discretion of the relevant authorities and may result in regulatory or other enforcement actions, as well as civil and criminal liability.

On December 15, 2021, a federal grand jury in the Central District of California returned a federal criminal indictment against Amplify Energy Corp., Beta Operating Company, LLC, and San Pedro Bay Pipeline Company in connection with the Incident. The indictment alleges that we committed a misdemeanor violation of the federal Clean Water Act for negligently discharging oil into the contiguous zone of the United States. The United States Attorney's Office for the Central District of California has stated that its investigation of the Incident and related matters is ongoing. State authorities are conducting parallel criminal investigations as well. We are continuing to cooperate with these federal and state investigations. The outcome of these investigations is uncertain, including whether they will result in additional criminal charges.

Our potential liabilities resulting from pending and future claims, lawsuits and enforcement actions relating to the Incident, together with the potential cost of implementing remedies sought in the various proceedings, cannot be fully estimated at this time but they may have a material adverse impact on our business, results of operations and financial condition and the implementation of our strategic agenda. For further information, please see Note 16, “Commitments and Contingencies — Litigation and Environmental” of the Notes to Consolidated Financial Statements and “Part I — Item 3. Legal Proceedings” included in this Annual Report.

We may be subject to increased permitting obligations and regulatory scrutiny as a result of the Incident.

The Incident may result in more stringent permitting obligations and regulation of our and other oil and gas activities including in federal waters off California and elsewhere, particularly relating to environmental, health and safety protection controls, oversight of oil and gas operations and required financial assurance. Regulatory or legislative action may impact the industry as a whole and could be directed specifically towards operators similarly situated to us. Our ability to obtain the necessary permits to repair the Pipeline and continue operations may be significantly delayed by regulators or such permits could be denied. The California Coastal Commission requested that the Office for Coastal Management of the National Oceanic and Atmospheric Administration approve a Coastal Zone Management Act consistency review of our U.S. Army Corps of Engineers Nationwide Permit 12 application for the proposed permanent repair to the Pipeline. We cannot be certain of the timing or decisions with regard to these permitting obligations and regulations, which could negatively impact our business.

Additionally, new regulations and legislation, as well as evolving practices, may increase the cost of compliance, require changes to our operations and strategic plans and impact our ability to capitalize on our assets.

The Incident may impact our ability to access financing on acceptable terms and may materially impact our liquidity.

The reputational consequences of the Incident, ongoing concerns surrounding costs arising from the Incident, ongoing contingencies related to the Incident and the impact of the Incident on our liquidity and financial performance could increase our financing costs and limit our access to financing on acceptable terms. Our ability to engage in trading activities may also be impacted due to counterparty concerns about our financial and business risk profile following the Incident. Such counterparties may require that we provide collateral or other forms of financial security for their obligations. Certain counterparties for our non-trading businesses may also require that we provide collateral for certain contractual obligations.

In addition, we may be unable to access liquidity under our Revolving Credit Facility in the event there are pending or threatened legal, arbitration or administrative proceedings which, if determined adversely, might reasonably be expected to have a material adverse effect on our ability to meet the payment obligations under our Revolving Credit Facility. Extended constraints on our ability to obtain financing and to engage in trading activities on acceptable terms (or at all) may put pressure on our liquidity. In addition, this could occur at a time when cash flows from our business operations may be constrained. In order to address severe liquidity constraints, we could be required to further reduce capital expenditures, sell strategic assets or obtain financing on terms that could have a significant adverse effect on stockholder returns and the implementation of our strategic plans.

We may not have adequate insurance to compensate us, and our insurers may not pay particular claims.

We currently maintain insurance that covers against certain losses and expenses associated with the Incident. However, we cannot guarantee that our insurance policies will cover all losses that we incur in connection with the Incident or that disputes over insurance claims will not arise with our insurance carriers. Additionally, the insurers may not pay particular claims or may take an extended period of time to do so. In addition, our insurance policies are subject to limitations and exclusions, which may increase our costs or lower our revenues, thereby possibly having a material adverse effect on our business, results of operations and financial condition. Finally, we cannot guarantee that we will be able to renew our insurance policies on the same or commercially reasonable terms, or at all, in the future.

The shut-in of the pipeline could negatively impact our production, liquidity, and, ultimately, our operations, results, and performance.

Our production depends, in part, upon our assets that are capable of commercial production not being shut-in (i.e., suspended from production). In response to the Incident, we have shut-in the pipeline impacted by the Incident and the Beta field, which has decreased our overall production volumes. This decrease in production will impact our ability to generate cash flows from operations, and we will experience a reduction in our available liquidity, which may adversely affect our ability to meet our anticipated working capital, debt service, and other liquidity needs. Additionally, in part due to permitting obligations and regulations discussed in this Annual Report, we cannot be certain whether and when, if at all, we will be able to restart operations at the Beta field.

The Incident has created significant risk to our reputation and has diverted, and will continue to divert, the attention of our management team.

The Incident has damaged our reputation, which may have a long-term impact on us. Adverse public, political and industry sentiment towards us, and oil and gas activities generally, could damage or impair our existing commercial relationships with counterparties, partners and governmental agencies and could impair our access to debt or capital, new investment opportunities, operatorships or other essential commercial arrangements with potential partners and governmental agencies. In addition, responding to the Incident may place a significant burden on our cash flow, which could also impede our ability to invest in new opportunities and deliver long-term growth.

In addition, our response to the Incident has required significant management focus. Key management and operating personnel are, and will need to continue, devoting substantial attention to responding to the Incident and to addressing the associated consequences for us, leaving them less time to devote to executing our strategic plans. In addition, we rely on recruiting and retaining high-quality employees to execute our strategic plans and to operate our business. The Incident response has placed significant demands on our employees, and the reputational damage suffered by us as a result of the Incident and any consequent adverse impact on our business could affect employee recruitment, productivity, retention and the results of our operations.

Risks Related to Our Business

Oil, natural gas and NGL prices are volatile, due to factors beyond our control, and greatly affect our business, results of operations and financial condition. Any decline in, or sustained low levels of, oil, natural gas and NGL prices will cause a decline in our cash flow from operations, which could materially and adversely affect our business, results of operations and financial condition.

Our revenues, operating results, profitability, liquidity, future growth and the value of our assets depend primarily on prevailing commodity prices. Historically, oil and natural gas prices have been volatile and fluctuate in response to changes in supply and demand, market uncertainty, and other factors that are beyond our control, including:

- the regional, domestic and foreign supply of oil, natural gas and NGLs;
- the level of commodity prices and expectations about future commodity prices;
- the level of global oil and natural gas exploration and production;
- localized supply and demand fundamentals, including the proximity and capacity of pipelines and other transportation facilities, and other factors that result in differentials to benchmark prices from time to time;
- the cost of exploring for developing, producing and transporting reserves;
- the price and quantity of foreign imports;
- political and economic conditions in oil producing countries, including conflicts in or among the Middle East, Africa, South America and Russia;
- the ability of members of the Organization of Petroleum Exporting Countries (“OPEC”) to agree to and maintain oil price and production controls;

- speculative trading in crude oil and natural gas derivative contracts;
- the level of consumer product demand;
- weather conditions and other natural disasters;
- risks associated with operating drilling rigs;
- technological advances affecting exploration and production operations and overall energy consumption;
- domestic and foreign governmental regulations and taxes;
- the impact of energy conservation efforts;
- the continued threat of terrorism and the impact of military and other action, including escalating tensions between Russia and Ukraine and the potential destabilizing effect such conflict may pose for the European continent or the global oil and natural gas markets
- the price and availability of competitors' supplies of oil and natural gas and alternative fuels; and
- overall domestic and global economic conditions.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil, natural gas and NGL price movements with any certainty. For example, for the five years ended December 31, 2021, the NYMEX-WTI oil future price ranged from a high of $84.65 per Bbl to a low of $(37.63) per Bbl, while the NYMEX-Henry Hub natural gas future price ranged from a high of $6.20 per MMBtu to a low of $1.48 per MMBtu. For the year ended December 31, 2021, the WTI posted prices ranged from a high of $84.65 per Bbl on October 26, 2021 to a low of $47.62 per Bbl on January 4, 2021 and NYMEX-Henry Hub natural gas market price ranged from a high of $6.20 per MMBtu on October 27, 2021 to a low of $2.45 per MMBtu on January 22, 2021. Likewise, NGLs, which are made up of ethane, propane, isobutane, normal butane and natural gasoline, each of which has different uses and different pricing characteristics, have sustained depressed realized prices during this period and are generally correlated with the price of oil. A further or extended decline in commodity prices could materially and adversely affect our business, results of operations and financial condition.

If commodity prices decline and/or remain depressed for a prolonged period, a significant portion of our development projects may become uneconomic and result in write downs of the value of our oil and natural gas properties, which may adversely affect our financial condition and our ability to fund our operations.

Oil, natural gas and NGL prices have experienced significant volatility over the past few years. An extended decline in commodity prices could render many of our development and production projects uneconomical and result in a downward adjustment of our reserve estimates, which would reduce our borrowing base and our ability to fund our operations.

No impairment expense was recognized for the year ended December 31, 2021, and we recognized $477.0 million in impairment expense for the year ended December 31, 2020. An extended decline in commodity prices may cause us to write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties for impairments. We may in the future incur impairment charges that could have a material adverse effect on our results of operations in the period taken and our ability to borrow funds under our Revolving Credit Facility.

A pandemic, epidemic or outbreak of an infectious disease, such as COVID-19, may materially adversely affect our business.

The global or national outbreak of an infectious disease, such as COVID-19 or emerging variants, may cause disruptions to our business and operational plans, which may include (i) shortages of employees, (ii) unavailability of contractors and subcontractors, (iii) interruption of supplies from third parties upon which we rely, (iv) recommendations of, or restrictions imposed by, government and health authorities, including quarantines, and (v) restrictions that we and our contractors and subcontractors impose, including curtailment or shutting in of production, to ensure the safety of employees and others. While it is not possible to predict their extent or duration, these disruptions may have a material adverse effect on our business, financial condition and results of operations.

Further, COVID-19 or emerging variants may adversely impact the supply chain for equipment or services needed for our operations, including as a result of mandatory shutdowns and other pandemic-related measures implemented in locations where such equipment or services are manufactured or distributed. We may also be impacted by significant disruptions to the operations of our logistics and service providers.

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

Our future success depends on the skills, experience and efforts of our key executive officers. The sudden loss of any of these executives' services or our failure to appropriately plan for any expected key executive succession could materially and adversely affect our business and prospects, as we may not be able to find suitable individuals to replace them on a timely basis, if at all. Additionally, we also depend on our ability to attract and retain qualified personnel to operate and expand our business. If we fail to attract or retain talented new employees, our business and results of operations could be negatively affected. Workers may choose to pursue employment with our competitors or in other fields; this competition has become exacerbated by the increase in employee resignations currently taking place throughout the United States as a result of the COVID-19 pandemic, which is commonly referred to as the "great resignation."

We may be unable to maintain compliance with the covenants in the Revolving Credit Facility, which could result in an event of default thereunder that, if not cured or waived, would have a material adverse effect on our business and financial condition.

Under our Revolving Credit Facility, we are required to maintain (i) as of the date of determination, a maximum total debt to EBITDAX ratio of 4.00 to 1.00, (ii) a current ratio of not less than 1.00 to 1.00, and (iii) maintain a minimum hedging requirement to at least 30%-60% of our estimated production from total proved developed producing reserves. If we were to violate any of the covenants under our Revolving Credit Facility and were unable to obtain a waiver or amendment, it would be considered a default after the expiration of any applicable grace period. If we were in default under our Revolving Credit Facility, then the lenders may exercise certain remedies including, among others, declaring all borrowings outstanding thereunder, if any, immediately due and payable. This could adversely affect our operations and our ability to satisfy our obligations as they come due, because we might not have, or be able to obtain, sufficient funds to make these accelerated payments. In addition, our obligations under our Revolving Credit Facility are secured by mortgages on not less than 90% of the PV-9 value of our oil and gas properties (and at least 90% of the PV-9 value of the proved, developed and producing oil and gas properties), and if we are unable to repay our indebtedness under our Revolving Credit Facility, the lenders could seek to foreclose on our assets.

Restrictive covenants in our Revolving Credit Facility could limit our growth and our ability to finance our operations, fund our capital needs, respond to changing conditions and engage in other business activities that may be in our best interests.

Restrictive covenants in our Revolving Credit Facility impose significant operating and financial restrictions on us and our subsidiaries. These restrictions limit our ability to, among other things:

- incur additional liens;
- incur additional indebtedness;
- merge, consolidate or sell our assets;
- pay dividends or make other distributions or repurchase or redeem our stock;
- make certain investments; and
- enter into transactions with our affiliates.

Our Revolving Credit Facility also requires us to comply with certain financial maintenance covenants as discussed above. A breach of any of these covenants could result in a default under our Revolving Credit Facility. If a default occurs and remains uncured or unwaived, the administrative agent or majority lenders under our Revolving Credit Facility may elect to declare all borrowings outstanding thereunder, if any, together with accrued interest and other fees, to be immediately due and payable. The administrative agent or majority lenders under our Revolving Credit Facility would also have the right in these circumstances to terminate any commitments they have to provide further borrowings. If we are unable to repay our indebtedness when due or declared due, the administrative agent will also have the right to proceed against the collateral pledged to it to secure the indebtedness under our Revolving Credit Facility. If such indebtedness were to be accelerated, our assets may not be sufficient to repay in full our secured indebtedness.

We may also be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us by the restrictive covenants in our Revolving Credit Facility. The terms and conditions of our Revolving Credit Facility affect us in several ways, including:

- requiring us to dedicate a substantial portion of our cash flow from operations to service our existing debt, thereby reducing the cash available to finance our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate;
- increasing our vulnerability to economic downturns and adverse developments in our business;
- limiting our ability to access the capital markets to raise capital on favorable terms or to obtain additional financing for working capital, capital expenditures or acquisitions or to refinance existing indebtedness;
- placing restrictions on our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations;
- placing us at a competitive disadvantage relative to competitors with lower levels of indebtedness in relation to their overall size or less restrictive terms governing their indebtedness; and
- limiting management’s discretion in operating our business.

Our lenders periodically redetermine the amount we may borrow under our Revolving Credit Facility, which may materially impact our operations.

Our Revolving Credit Facility allows us to borrow in an amount up to the borrowing base, which is primarily based on the estimated value of our oil and natural gas properties and our commodity derivative contracts as determined semi-annually by our lenders in their sole discretion. The borrowing base is subject to redetermination on at least a semi-annual basis primarily based on an engineering report with respect to our estimated natural gas, oil and NGL reserves, which takes into account the prevailing natural gas, oil and NGL prices at such time, as adjusted for the impact of our commodity derivative contracts. Accordingly, declining commodity prices may have an impact on the amount we can borrow, which could affect our cash flows and ability to execute on our business plans. Any reduction in the borrowing base would materially and adversely affect our business and financing activities, limit our flexibility and management’s discretion in operating our business, and increase the risk that we may default on our debt obligations. In addition, as hedges roll off, the borrowing base is subject to further reduction. Our Revolving Credit Facility requires us to repay any deficiency over a certain period or pledge additional oil and gas properties to eliminate such deficiency, which we are required to do within 30 days of notice to do so. If our outstanding borrowings exceed the borrowing base and we are unable to repay the deficiency or pledge additional oil and gas properties to eliminate such deficiency, our failure to repay any of the installments due related to the borrowing base deficiency would constitute an event of default under the Revolving Credit Facility and as such, the lenders could declare all outstanding principal and interest to be due and payable, could freeze our accounts, or foreclose against the assets securing the obligations owed under our Revolving Credit Facility.

Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase significantly.

Borrowings under our Revolving Credit Facility bear interest at variable rates and expose us to interest rate risk. If interest rates increase, our debt service obligations on the variable rate indebtedness would increase even if the amount borrowed remained the same, and our net income and cash available for servicing our indebtedness would decrease.

Our hedging strategy may not effectively mitigate the impact of commodity price volatility from our cash flows, and our hedging activities could result in cash losses and may limit potential gains.

We intend to maintain a portfolio of commodity derivative contracts covering at least 30% - 60% of our estimated production from proved developed producing reserves over a one-to-three-year period at any given point in time. These commodity derivative contracts include natural gas, oil and NGL financial swaps. The prices and quantities at which we enter into commodity derivative contracts covering our production in the future will be dependent upon oil and natural gas prices and price expectations, at the time we enter into these transactions, which may be substantially higher or lower than current or future oil and natural gas prices. Accordingly, our price hedging strategy may not protect us from significant declines in oil, natural gas and NGL prices received for our future production. Many of the derivative contracts to which we will be a party will require us to make cash payments to the extent the applicable index exceeds a predetermined price, thereby limiting our ability to realize the benefit of increases in oil, natural gas and NGL prices. If our actual production and sales for any period are less than our hedged production and sales for that period (including reductions in production due to operational delays) or if we are unable to perform our drilling activities as planned, we might be forced to satisfy all or a portion of our hedging obligations without the benefit of the cash flow from our sale of the underlying physical commodity, which may materially impact our liquidity.

An increase in the differential between the NYMEX or other benchmark prices of oil and natural gas and the wellhead price we receive for our production could significantly reduce our cash flow and adversely affect our financial condition.

The prices that we receive for our oil and natural gas production often reflect a regional discount, based on the location of production, to the relevant benchmark prices, such as NYMEX or ICE, that are used for calculating hedge positions. The prices we receive for our production are also affected by the specific characteristics of the production relative to production sold at benchmark prices. For example, our California oil typically has a lower gravity, and a portion has higher sulfur content, than oil sold at certain benchmark prices. Therefore, because our oil requires more complex refining equipment to convert it into high value products, it may sell at a discount to those prices. These discounts, if significant, could reduce our cash flows and adversely affect our results of operations and financial condition.

Our estimated reserves and future production rates are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our estimated reserves.

It is not possible to measure underground accumulations of oil or natural gas in an exact way. The process of estimating natural gas and oil reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect our estimated quantities and present value of our reserves.

In order to prepare our estimates, we must project production rates and timing of operating and development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary.

The process also requires economic assumptions about matters such as natural gas and oil prices, drilling and operating expenses, capital expenditures and availability of funds.

Actual future production, oil prices, natural gas prices, revenues, development expenditures, operating expenses and quantities of recoverable reserves will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of our reserves. In addition, we may adjust our reserve estimates to reflect production history, results of development, existing commodity prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues from our reserves is the current market value of our estimated reserves. We generally base the estimated discounted future net cash flows from our reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate.

Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations and financial condition.

The standardized measure of our estimated proved reserves is not necessarily the same as the current market value of our estimated proved oil and natural gas reserves.

The present value of future net cash flows from our proved reserves shown in this report, or standardized measure, may not be the current market value of our estimated natural gas and oil reserves. In accordance with rules established by the SEC and the FASB, we base the estimated discounted future net cash flows from our proved reserves on the trailing 12-month average oil and gas index prices, calculated as the unweighted arithmetic average for the first-day-of-the-month price for each month and costs in effect on the date of the estimate, holding the prices and costs constant throughout the life of the properties. Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than the current estimate. In addition, the 10% discount factor we use when calculating discounted future net cash flows for reporting requirements, which is required by the SEC and FASB, is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general.

The failure to replace our proved oil and natural gas reserves could adversely affect our business, financial condition, results of operations, production and cash flows.

Producing oil and natural gas reservoirs are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and, production and therefore, our cash flow are highly dependent on our success in efficiently developing and exploiting our current reserves. Our production decline rates may be significantly higher than currently estimated if our wells do not produce as expected. Further, our decline rate may change when we drill additional wells or make acquisitions. We may not be able to develop, find or acquire additional reserves to replace our current and future production at economically acceptable terms, which would materially and adversely affect our business, financial condition and results of operations.

If we reduce our capital spending in an effort to conserve cash, this would likely result in production being lower than anticipated, and could result in reduced revenues, cash flow from operations and income. Further, if the borrowing base under our Revolving Credit Facility decreases, or our revenues decrease, as a result of lower oil or natural gas prices or for any other reason, we may not be able to obtain the capital necessary to sustain our operations.

Developing and producing oil and natural gas are costly and high-risk activities with many uncertainties that may result in a total loss of investment or otherwise adversely affect our business, financial condition, results of operations and cash flows.

Our drilling activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling for oil and natural gas often involves unprofitable efforts, not only from dry holes, but also from wells that are productive but do not produce sufficient oil or natural gas to return a profit at then-realized prices after deducting drilling, operating and other costs. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that oil or natural gas is present or that it can be produced economically. The costs of our development and production activities are subject to numerous uncertainties beyond our control and increases in those costs can adversely affect the economics of a project. Further, our development and production operations may be curtailed, delayed, canceled or otherwise negatively impacted as a result of other factors, including:

- high costs, shortages or delivery delays of rigs, equipment, labor, electrical power or other services;
- unusual or unexpected geological formations;
- composition of sour natural gas, including sulfur, carbon dioxide and other diluent content;
- unexpected operational events and conditions;
- failure of down hole equipment and tubulars;

- loss of wellbore mechanical integrity;
- failure, unavailability or shortage of capacity of gathering and transportation pipelines, or other transportation facilities;
- human errors, facility or equipment malfunctions and equipment failures or accidents, including acceleration of deterioration of our facilities and equipment due to the highly corrosive nature of sour natural gas;
- title problems;
- loss of drilling fluid circulation;
- hydrocarbon or oilfield chemical spills;
- fires, blowouts, surface craterings and explosions;
- surface spills or underground migration due to uncontrollable flows of oil, natural gas, formation water or well fluids;
- delays imposed by or resulting from compliance with environmental and other governmental or regulatory requirements; and
- adverse weather conditions and natural disasters.

Any of these risks can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination or loss of wells and other regulatory penalties. In the event that planned operations are delayed or canceled, or existing wells or development wells have lower than anticipated production due to one or more of the factors above or for any other reason, our financial condition and results of operations may be adversely affected. If any of these factors were to occur with respect to a particular field, we could lose all or a part of our investment in the field or we could fail to realize the expected benefits from the field, either of which could materially and adversely affect our business, financial condition, results of operations and cash flows.

Expenses not covered by our insurance could have a material adverse effect on our financial position and results of operations.

Our operations are subject to all of the hazards and operating risks associated with drilling for and production of oil and natural gas, including natural disasters, the risk of fire, explosions, blowouts, surface cratering, uncontrollable flows of natural gas, oil and formation water, pipe or pipeline failures, abnormally pressured formations, casing collapses and environmental hazards such as oil spills, natural gas leaks, ruptures or discharges of toxic gases, all of which could cause substantial financial losses. In addition, our operations are subject to risks associated with hydraulic fracturing, including any mishandling, surface spillage or potential underground migration of fracturing fluids, including chemical additives. The location of any properties and other assets near populated areas, including residential areas, commercial business centers and industrial sites, could significantly increase the level of potential damages resulting from these risks. The occurrence of any of these or other similar events could result in substantial losses to us due to injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, cleanup responsibilities, regulatory investigation and penalties, suspension or disruption of operations, substantial revenue losses and repairs to resume operations.

We maintain insurance coverage against potential losses that we believe is customary in the industry. However, insurance against all operational risk is not available to us. These insurance policies may not cover all liabilities, claims, fines, penalties or costs and expenses that we may incur in connection with our business and operations, including those related to environmental claims. Pollution and environmental risks generally are not fully insurable. In addition, we cannot assure you that we will be able to maintain adequate insurance at rates we consider reasonable. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. A liability, claim or other loss not fully covered by insurance could have a material adverse effect on our business, financial position, results of operations and cash flows. For a discussion of the risks surrounding insurance associated with the Incident, see "— We may not have adequate insurance to compensate us, and our insurers may not pay particular claims."

The production from our Wyoming Bairoil properties could be adversely affected by the cessation or interruption of the supply of CO2 to those properties.

We inject water and CO_2 into formations on substantially all of the Wyoming Bairoil properties to increase production of oil and natural gas. The additional production and reserves attributable to the use of enhanced recovery methods are inherently difficult to predict. If we are unable to produce oil and gas by injecting CO_2 in the manner or to the extent that we anticipate, our future results of operations and financial condition could be materially adversely affected. Additionally, our ability to utilize CO_2 to enhance production is subject to our ability to obtain sufficient quantities of CO_2. If, under our CO_2 supply contracts, the supplier is unable to deliver its contractually required quantities of CO_2 to us, or if our ability to access adequate supplies is impeded, then we may not have sufficient CO_2 to produce oil and natural gas in the manner or to the extent that we anticipate, and our future oil and gas production volumes will be negatively impacted.

Many of our properties are in areas that may have been partially depleted or drained by offset wells.

Many of our properties are in areas that may have already been partially depleted or drained by earlier offset drilling. The owners of leasehold interests lying contiguous or adjacent to or adjoining any of our properties could take actions, such as drilling additional wells that could adversely affect our operations. When a new well is completed and produced, the pressure differential in the vicinity of the well causes the migration of reservoir fluids towards the new wellbore (and potentially away from existing wellbores). As a result, the drilling and production of these potential locations could cause a depletion of our proved reserves and may inhibit our ability to further exploit and develop our reserves.

Our expectations for future development activities are planned to be realized over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of such activities.

We have identified drilling, recompletion and development locations and prospects for future drilling, recompletion and development. These drilling, recompletion and development locations represent a significant part of our future drilling and enhanced recovery opportunity plans. We cannot predict in advance of drilling, testing and analysis of data whether any particular drilling location will yield production in sufficient quantities to recover drilling or completion costs or to be economically viable. Even if sufficient amounts of oil or natural gas reserves exist, we may damage the potentially productive hydrocarbon bearing formation or experience mechanical difficulties while drilling or completing the well, possibly resulting in a reduction in production from the well or abandonment of the well. If we drill dry holes in our current and future drilling locations, our drilling success rate may decline and materially harm our business. Our ability to drill, recomplete and develop locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory approvals, negotiation of agreements with third parties, commodity prices, costs, the generation of additional seismic or geological information, the availability of drilling rigs, drilling results, construction of infrastructure and lease expirations. Because of these uncertainties, we cannot be certain of the timing of these activities or that they will ultimately result in the realization of estimated proved reserves or meet our expectations for success. As such, our actual drilling and enhanced recovery activities may materially differ from our current expectations, which could have a significant adverse effect on our estimated reserves, financial condition, results of operations and cash flows.

Part of our strategy may involve using horizontal drilling and completion techniques, which involve risks and uncertainties in their application.

Our operations may involve utilizing some of the latest drilling and completion techniques as developed by us and our service providers. Risks that we may face while drilling horizontal wells include, but are not limited to, the following:

- landing our wellbore in the desired drilling zone;
- staying in the desired drilling zone while drilling horizontally through the formation;
- running our casing the entire length of the wellbore; and
- being able to run tools and other equipment consistently through the horizontal wellbore.

Risks that we may face while completing wells include, but are not limited to, the following:

- the ability to fracture stimulate the target reservoir formation as planned, including the planned number of stages;

- the ability to run tools the entire length of the wellbore during completion operations; and
- the ability to successfully clean out the wellbore after completion of the final fracture stimulation stage.

If our drilling results are less than anticipated, the return on our investment for a particular project may not be as attractive as we anticipated and we could incur material write-downs of unevaluated properties, and the value of our undeveloped acreage could decline in the future.

Our potential use of 2-D and 3-D seismic data is subject to interpretation and may not accurately identify the presence of oil and natural gas, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies and we could incur losses as a result of such expenditures. As a result, future drilling activities may not be successful or economical, which could have a material adverse impact on our financial condition, results of operations and cash flows.

SEC rules could limit our ability to book additional PUDs in the future.

SEC rules require that, subject to limited exceptions, PUDs may only be booked if they relate to wells scheduled to be drilled within five years after the date of booking. This requirement has limited and will likely continue to limit our ability to book additional PUDs, especially in a time of depressed commodity prices. Moreover, we may be required to write down our PUDs if we do not drill those wells within the required five-year timeframe.

The unavailability or high cost of rigs, equipment, supplies and crews could delay our operations, increase our costs and delay forecasted revenue.

Our industry is cyclical, and historically there have been periodic shortages of rigs, equipment, supplies and crew. Sustained declines in oil and natural gas prices may reduce the number of service providers for such rigs, equipment, supplies and crews, contributing to or resulting in shortages. Alternatively, during periods of higher oil and natural gas prices, the demand for rigs, equipment, supplies and crews is increased and can lead to shortages of, and increasing costs for, development equipment, supplies, services and personnel. Shortages of, or increasing costs for, experienced development crews and oil field equipment and services could restrict the Company's ability to drill the wells and conduct the operations that it currently has planned relating to the fields where our properties are located. In addition, some of our operations require supply materials for production, such as CO_2, which could become subject to shortages and increased costs. Any delay in the development of new wells or a significant increase in development costs could reduce our revenues and impact our development plan, which would thus affect our financial conduction, results of operations and our cash flows.

We may incur losses as a result of title defects in the properties in which we invest.

The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition. While we typically obtain title opinions prior to commencing drilling operations on a lease or in a unit, the failure of title may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the minerals under the property.

Development and production of oil and natural gas in offshore waters have inherent and historically higher risk than similar activities onshore.

Our offshore operations are subject to a variety of operating risks specific to the marine environment, such as a dependence on a limited number of electrical transmission lines, as well as capsizing, collisions and damage or loss from adverse weather conditions. Offshore activities are subject to more extensive governmental regulation than our other oil and natural gas activities. We are vulnerable to the risks associated with operating offshore California, including risks relating to:

- impacts of climate change and natural disasters such as earthquakes, tidal waves, mudslides, fires and floods;

- oil field service costs and availability;
- compliance with environmental and other laws and regulations;
- third-party marine vessels, including situations similar to the Incident;
- remediation and other costs resulting from oil spills, releases of hazardous materials and other environmental and natural resource damages; and
- failure of equipment or facilities.

In addition to lost production and increased costs, these hazards could cause serious injuries, fatalities, contamination or property damage for which we could be held responsible. The potential consequences of these hazards are particularly severe for us because significant portions of our offshore operations are conducted in environmentally sensitive areas, including areas with significant residential populations and public and commercial infrastructure. An accidental oil spill or release on or related to offshore properties and operations could expose us to joint and several strict liability, without regard to fault, under applicable law for all containment and oil removal costs and a variety of public and private damages including, but not limited to, the costs of remediating a release of oil, natural resource damages, and economic damages suffered by persons adversely affected by an oil spill. If an oil discharge or substantial threat of discharge were to occur, we may be subject to regulatory scrutiny and liable for costs and damages, which costs and damages could be material to our business, financial condition or results of operations and could subject us to criminal and civil penalties. Finally, maintenance activities undertaken to reduce operational risks can be costly and can require exploration, exploitation and development operations to be curtailed while those activities are being completed.

Adverse developments in our operating areas could adversely affect our business, financial condition, results of operations and cash flows.

Our properties are located in the Rockies, federal waters offshore Southern California, East Texas / North Louisiana, Oklahoma and Eagle Ford. An adverse development in the oil and natural gas business of any of these geographic areas, such as in our ability to attract and retain field personnel or in our ability to comply with local regulations, could adversely affect our business, financial condition, results of operations and cash flows.

We are dependent upon a small number of significant customers for a substantial portion of our production sales. The loss of those customers, if not replaced, could reduce our revenues and have a material adverse effect on our financial condition and results of operations.

We had three customers that each accounted for 10% or more of total reported revenues for the year ended December 31, 2021. The loss of these customers or any significant customer, should we be unable to replace them, could adversely affect our revenues and have a material adverse effect on our financial condition and results of operations. Also, if any significant customer reduces the volume it purchases from us, we could experience a temporary interruption in sales of, or may receive a lower price for, our production, and our revenues and cash flows could decline. We cannot assure you that any of our customers will continue to do business with us or that we will continue to have access to suitably liquid markets for our future production. See “Item 1. Business — Operations — Marketing and Major Customers.”

The inability of our significant customers to meet their obligations to us may adversely affect our financial results.

We are subject to credit risk due to concentration of our oil and natural gas receivables. The inability or failure of our significant customers, or any purchasers of our production, to meet their payment obligations to us or their insolvency or liquidation could have a material adverse effect on our results of operations. To the extent that purchasers of our production rely on access to the credit or equity markets to fund their operations, there could be an increased risk that those purchasers could default in their contractual obligations to us. If for any reason we were to determine that it was probable that some or all of the accounts receivable from any one or more of the purchasers of our production were uncollectible, we would recognize a charge in the earnings of that period for the probable loss and could suffer a material reduction in our liquidity and cash flows.

We are exposed to trade credit risk in the ordinary course of our business activities.

We are exposed to risks of loss in the event of nonperformance by our vendors and other counterparties. Some of our vendors and other counterparties may be highly leveraged and subject to their own operating and regulatory risks. Many of our vendors and other counterparties finance their activities through cash flow from operations, the incurrence of debt or the issuance of equity. The combination of reduction of cash flow resulting from declines in commodity prices and the lack of availability of debt or equity financing may result in a significant reduction in our vendors' and other counterparties' liquidity and ability to make payments or perform on their obligations to us. Even if our credit review and analysis mechanisms work properly, we may experience financial losses in our dealings with other parties. Any increase in the nonpayment or nonperformance by our vendors and/or counterparties could adversely affect our business, financial condition, results of operations and cash flows.

Conservation measures, technological advances and increasing public attention to climate change and environmental matters could reduce demand for oil and natural gas and have an adverse effect on our business, financial condition and reputation.

Fuel conservation measures, alternative fuel requirements, incentives to conserve energy or use alternative energy sources, increasing consumer demand for alternatives to oil and natural gas, and technological advances in fuel economy and energy generation devices could reduce demand for oil and natural gas. Such initiatives or related activism aimed at limiting climate change and reducing air pollution, as well as negative investor sentiment toward our industry and the impact of the changing demand for oil and natural gas services and products may have a material adverse effect on our business, financial condition, results of operations, cash flows, and ability to access capital. Negative public perception regarding us and/or our industry resulting from, among other things, concerns raised by advocacy groups about climate change, may also lead to increased litigation risk and regulatory, legislative, and judicial scrutiny, which may, in turn, lead to new state and federal safety and environmental laws, regulations, guidelines and enforcement interpretations. Governmental authorities exercise considerable discretion in the timing and scope of permit issuance and the public may engage in the permitting process, including through intervention in the courts. Negative public perception could cause the permits we need to conduct our operations to be withheld, delayed, or burdened by requirements that restrict our ability to profitably conduct our business. In addition, claims have been made against certain energy companies alleging that GHG emissions from oil and natural gas operations constitute a public nuisance or have caused other redressable injuries under federal and/or state common law. While our business is not a party to any such litigation, we could be named in actions making similar allegations. An unfavorable ruling in any such case could adversely impact our business, financial condition and results of operations. Moreover, parties concerned about the potential effects of climate change have directed their attention at sources of funding for energy companies, which has resulted in certain financial institutions, funds and other sources of capital, restricting or eliminating their investment in oil and natural gas activities.

We may be unable to compete effectively with larger companies.

The oil and natural gas industry is intensely competitive with respect to acquiring prospects and productive properties, marketing oil and natural gas and securing equipment and trained personnel. Our ability to acquire additional properties and to discover reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Many of our larger competitors not only drill for and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis and many of our competitors have access to capital at a lower cost than that available to us. These companies may be able to pay more for oil and natural gas properties and evaluate, bid for and purchase a greater number of properties than our financial, technical or personnel resources permit. In addition, there is substantial competition for investment capital in the oil and natural gas industry. These larger companies may have a greater ability to continue development activities during periods of low oil and natural gas prices and to absorb the burden of present and future federal, state, local and other laws and regulations. Furthermore, we may not be able to aggregate sufficient quantities of production to compete with larger companies that are able to sell greater volumes of production to intermediaries, thereby reducing the realized prices attributable to our production. Any inability to compete effectively with larger companies could have a material adverse impact on our business activities, financial condition, results of operations and cash flows.

Our business depends in part on pipelines, gathering systems and processing facilities owned by us or others. Any limitation in the availability of those facilities could interfere with our ability to market our oil and natural gas production.

The marketability of our oil and natural gas production depends in part on the availability, proximity and capacity of pipelines and other transportation methods, gathering systems and processing facilities owned by third parties. The amount of oil and natural gas that can be produced and sold is subject to curtailment in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage or lack of contracted capacity on such systems. For example, our ability to produce and sell oil from the Beta Properties will depend on the availability of the pipeline infrastructure between platforms as well as the San Pedro Bay Pipeline for delivery of that oil to shore, and any unavailability of that pipeline infrastructure or pipeline could cause us to shut in all or a portion of the production from the Beta Properties for the length of such unavailability. Our access to transportation options can also be affected by U.S. federal and state regulation of oil and natural gas production and transportation, general economic conditions and changes in supply and demand. The curtailments arising from these and similar circumstances may last from a few days to several months. In many cases, we are provided with only limited, if any, notice as to when these circumstances will arise and their duration. Any significant curtailment in gathering system or transportation or processing facility capacity could reduce our ability to market our oil and natural gas production and harm our business, financial condition, results of operations and cash flows.

We have limited control over the activities on properties we do not operate.

Some of the properties in which we have an interest are operated by other companies and involve third-party working interest owners. As a result, we have limited ability to influence or control the operation or future development of such properties, including compliance with environmental, safety and other regulations, or the amount of capital expenditures that we will be required to fund with respect to such properties. Moreover, we are dependent on the other working interest owners of such projects to fund their contractual share of the capital expenditures of such projects. In addition, a third-party operator could also decide to shut-in or curtail production from wells, or plug and abandon marginal wells, on properties owned by that operator during periods of lower crude oil or natural gas prices. These limitations and our dependence on the operator and third-party working interest owners for these projects could cause us to incur unexpected future costs, lower production and materially and adversely affect our financial condition and results of operations.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations.

Our oil and natural gas development and production operations are subject to complex and stringent laws and regulations administered by governmental authorities vested with broad authority relating to the exploration for and the development, production and transportation of oil and natural gas. To conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. Failure to comply with laws and regulations applicable to our operations, including any evolving interpretation and enforcement by governmental authorities, could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our oil and natural gas development and production operations are also subject to stringent and complex federal, state and local laws and regulations governing the discharge of materials into the environment, worker health and safety aspects of our operations, or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations applicable to our operations, including the acquisition of a permit before conducting regulated drilling activities; the restriction of types, quantities and concentration of materials that can be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands, seismically active areas and other protected areas; the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from our operations. Numerous governmental authorities, such as the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly compliance measures or corrective actions. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, the imposition of investigatory or remedial obligations, the suspension or revocation of necessary permits, licenses and authorizations, the requirement that additional pollution controls be installed and, in some instances, the issuance of orders limiting or prohibiting some or all of our operations. We may also experience delays in obtaining or be unable to obtain required permits, which may delay or interrupt our operations and limit our growth and revenue. In addition, the long-term trend in environmental regulation has been to place more restrictions and limitations on activities that may affect the environment. Thus, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations.

Under certain environmental laws that impose strict as well as joint and several liability, we may be required to remediate contaminated properties currently or formerly owned or operated by us or facilities of third parties that received waste generated by our operations regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. Moreover, public interest in the protection of the environment has increased in recent years. New laws and regulations continue to be enacted, particularly at the state level, and, under the Biden Administration, the long-term trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. To the extent laws are enacted, or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business, prospects, financial condition or results of operations could be materially adversely affected.

Further, the Mineral Leasing Act of 1920, as amended (the "Mineral Act") prohibits ownership of any direct or indirect interest in federal onshore oil and natural gas leases by a foreign citizen or a foreign entity except through equity ownership in a corporation formed under the laws of the United States or of any U.S. State or territory, and only if the laws, customs, or regulations of their country of origin or domicile do not deny similar or like privileges to citizens or entities of the United States. If these restrictions are violated, the oil and natural gas lease can be canceled in a proceeding instituted by the United States Attorney General. We qualify as an entity formed under the laws of the United States or of any U.S. state or territory. Although the regulations promulgated and administered by the BLM pursuant to the Mineral Act provide for agency designations of non-reciprocal countries, there are presently no such designations in effect. It is possible that our stockholders may be citizens of foreign countries who do not own their stock in a U.S. corporation, or that even if such stock are held through a U.S. corporation, their country of citizenship may be determined to be non-reciprocal countries under the Mineral Act. In such event, any federal onshore oil and natural gas leases held by us could be subject to cancellation based on such determination.

See "Item 1. Business — Environmental, Occupational Health and Safety Matters and Regulations" and "— Other Regulation of the Oil and Natural Gas Industry" for a description of the more significant laws and regulations that affect us.

Climate change legislation or regulations restricting emissions of "greenhouse gases," or GHGs, could result in increased operating costs and reduced demand for the oil and natural gas that we produce.

In December 2009, the EPA published its findings that emissions of GHGs present an endangerment to public health and the environment because emissions of such gases are contributing to the warming of the Earth's atmosphere and other climatic changes. Based on these findings, the EPA has adopted and implemented regulations to restrict emissions of GHGs under existing provisions of the CAA. In addition, the EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources on an annual basis in the United States, including, among others, certain oil and natural gas production facilities, which includes certain of our operations. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas we produce. Such climate change regulatory and legislative initiatives could have a material adverse effect on our business, financial condition and results of operations.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. However, the United States House of Representatives passed H.R. 5376, known as the Build Back Better Act on November 3, 2021. The House version of the bill targets methane from oil and gas sources by proposing to implement fees for excess methane leaking from wells, storage sites and pipelines as well as fees for new producing and non-producing oil and gases leases and off-shore pipelines. In the absence of such federal climate legislation, almost one-half of the states have taken legal measures to reduce emissions of GHGs, including through the planned development of GHG emission inventories and/or regional GHGs cap and trade programs. In addition, on an international level, the United States was one of nearly 200 countries to sign an international climate change agreement in Paris, France that requires member countries to set their own GHG emission reduction goals beginning in 2020. However, the United States formally announced its intent to withdraw from the Paris Agreement in November 2019, which became effective in November 2020. On January 20, 2021, President Biden issued written notification to the United Nations of the United States' intention to rejoin the Paris Agreement, which will become effective on February 19, 2021. In addition, various states and local governments have vowed to continue to enact regulations to achieve the goals of the Paris Agreement.

Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations that require reporting of GHGs or otherwise limit emissions of GHGs from our equipment and operations could require us to incur costs to monitor and report on GHG emissions or reduce emissions of GHGs associated with our operations, and such requirements also could adversely affect demand for the oil and natural gas that we produce. Finally, it should be noted that most scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations. For example, such effects could adversely affect or delay demand for the oil or natural gas produced or cause us to incur significant costs in preparing for or responding to the effects of climatic events themselves. Potential adverse effects could include disruption of our production activities, increases in our costs of operation or reductions in the efficiency of our operations, impacts on our personnel, supply chain, or distribution chain, as well as potentially increased costs for insurance coverages in the aftermath of such effects. Our ability to mitigate the adverse physical impacts of climate change depends in part upon our disaster preparedness and response and business continuity planning. See "Item 1. Business — Environmental, Occupational Health and Safety Matters and Regulations — Regulation of "Greenhouse Gas" Emissions for a description of the climate change laws and regulations that affect us.

The listing of a species as either "threatened" or "endangered" under the federal Endangered Species Act could result in increased costs, new operating restrictions, or delays in our operations, which could adversely affect our results of operations and financial condition.

The ESA and analogous state laws regulate activities that could have an adverse effect on threatened and endangered species. Operations in areas where threatened or endangered species or their habitat are known to exist may require us to incur increased costs to implement mitigation or protective measures and also may restrict or preclude our activities in those areas or during certain seasons, such as breeding and nesting seasons. The listing of species in areas where we operate or, alternatively, entry into certain range-wide conservation planning agreements could result in increased costs to us from species protection measures, time delays or limitations on our activities, which costs, delays or limitations may be significant and could adversely affect our results of operations and financial position.

The third parties on whom we rely for gathering and transportation services are subject to complex federal, state and other laws that could adversely affect the cost, manner or feasibility of conducting our business.

The operations of the third parties on whom we rely for gathering and transportation services are subject to complex and stringent laws and regulations that require obtaining and maintaining numerous permits, approvals and certifications from various federal, state and local government authorities. These third parties may incur substantial costs in order to comply with existing laws and regulations. If existing laws and regulations governing such third-party services are revised or reinterpreted, or if new laws and regulations become applicable to their operations, these changes may affect the costs that we pay for such services. Similarly, a failure to comply with such laws and regulations by the third parties on whom we rely for gathering and transportation services could impact the availability of those services. Any potential impact to the availability of gathering and transportation services could impact our ability to market and sell our production, which could have a material adverse effect on our business, financial condition and results of operations. See "Item 1. Business — Environmental, Occupational Health and Safety Matters and Regulations" and "— Other Regulation of the Oil and Natural Gas Industry" for a description of the laws and regulations that affect the third parties on whom we rely for gathering and transportation services.

Oil and natural gas producers' operations, especially those using hydraulic fracturing, are substantially dependent on the availability of water and the disposal of waste, including produced water and drilling fluids. Restrictions on the ability to obtain water or dispose of waste may impact our operations.

Water is an essential component of oil and natural gas production during the drilling, and in particular, hydraulic fracturing, process. Our inability to locate sufficient amounts of water, or dispose of or recycle water used in our development and production operations, could adversely impact our operations. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of natural gas. The Clean Water Act imposes restrictions and strict controls regarding the discharge of produced waters and other natural gas and oil waste into "waters of the United States." Permits must be obtained to discharge pollutants to such waters and to conduct construction activities in such waters, which include certain wetlands. The Clean Water Act and similar state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of pollutants and unauthorized discharges of reportable quantities of oil and other hazardous substances. State and federal discharge regulations prohibit the discharge of produced water and sand, drilling fluids, drill cuttings and certain other substances related to the natural gas and oil industry into coastal waters. Compliance with current and future environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells, and the disposal and recycling of produced water, drilling fluids, and other wastes, may increase our operating costs and cause delays, interruptions or termination of our operations, the extent of which cannot be predicted. In addition, in some instances, the operation of underground injection wells for the disposal of waste has been alleged to cause earthquakes. In some jurisdictions, such issues have led to orders prohibiting continued injection or the suspension of drilling in certain wells identified as possible sources of seismic activity or resulted in stricter regulatory requirements relating to the location and operation of underground injection wells. For example, we conduct oil and gas drilling and production operations in the Mississippian Lime formation in Oklahoma, a high-water play, which requires us to dispose of large volumes of saltwater generated as part of our operations. In 2015, the Oklahoma Geological Survey attributed an increase in seismic activity in Oklahoma to saltwater disposal wells in the Arbuckle formation. Around the same time, the OCC, whose Oil and Gas Conservation Division regulates oil and gas operations in Oklahoma, began issuing regulations targeting saltwater disposal activities in certain areas of interest within the Arbuckle formation. The regulations include operational requirements (i.e., mechanical integrity testing of wells permitted for disposal of 20,000 or more barrels of water per day, daily monitoring and recording of well pressure and discharge volume), as well as orders to shut-in wells, reduce well depths, or decrease disposal volumes. Under these regulations, in 2016 and 2017, the OCC ordered us to limit the volume of saltwater disposed of in saltwater disposal wells in the Arbuckle formation and established caps for ten of our saltwater disposal wells in February 2017, which caps are still in place. To ensure that we had an adequate number of wells for disposal, we secured permits for additional saltwater disposal wells outside of the Arbuckle formation. We timely satisfied all OCC saltwater disposal requirements, while maintaining our production base without any negative material impact. However, any additional orders or regulations addressing concerns about seismic activity from well injection in jurisdictions where we operate could affect our operations. See “Item 1. Business — Environmental, Occupational Health and Safety Matters and Regulations — Water Discharges and Other Waste Discharges & Spills” and “— Hydraulic Fracturing” for an additional description of the laws and regulations relating to the discharge of water and other wastes and hydraulic fracturing that affect us.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays and adversely affect our production.

Hydraulic fracturing is an essential and common practice in the oil and gas industry used to stimulate production of natural gas and/or oil from dense subsurface rock formations. Hydraulic fracturing involves using water, sand and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow flow of hydrocarbons into the wellbore. We routinely apply hydraulic fracturing techniques in our drilling and completion programs. While hydraulic fracturing has historically been regulated by state oil and natural gas commissions, the practice has become increasingly controversial in certain parts of the country, resulting in increased scrutiny and regulation. See “Item 1. Business — Environmental, Health and Safety Matters and Regulations — Hydraulic Fracturing” for a description of the federal and state legislative and regulatory initiatives relating to hydraulic fracturing that affect us.

If new laws or regulations that significantly restrict hydraulic fracturing are adopted at the state and local level, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from dense subsurface rock formations and, in the event of prohibitions, may preclude our ability to drill wells. In addition, if hydraulic fracturing becomes further regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA or other federal agencies, our fracturing activities could become subject to additional permitting requirements and result in permitting delays as well as potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

The cost of decommissioning is uncertain.

We are required to maintain reserve funds to provide for the payment of decommissioning costs associated with the Beta Properties. The estimates of decommissioning costs are inherently imprecise and subject to change due to changing cost estimates, oil and natural gas prices and other factors. If actual decommissioning costs exceed such estimates, or we are required to provide a significant amount of collateral in cash or other security as a result of a revision to such estimates, our financial condition, results of operations and cash flows may be materially adversely affected.

We may be required to post cash collateral pursuant to our agreements with sureties under our existing or future bonding arrangements, which may have a material adverse effect on our liquidity and our ability to execute our capital expenditure plan, our ARO plan and comply with our existing debt instruments.

Pursuant to the terms of our existing bonding arrangements with various sureties in connection with the decommissioning obligations related to our Beta Properties, or under any future bonding arrangements we may enter into, we may be required to post collateral at any time, on demand, at the sureties' sole discretion. If additional collateral is required to support surety bond obligations, this collateral would probably be in the form of cash or letters of credit, certificate of deposit or other similar forms of liquid collateral. We cannot provide assurance that we will be able to satisfy collateral demands for current bonds or for future bonds.

We entered into two escrow funding agreements with certain of our surety providers to fund interest-bearing escrow accounts to reimburse and indemnify the surety providers for any claims arising under the surety bonds related to the decommissioning of our Beta properties. If we fail to comply with our obligations under such escrow agreements, the surety providers may request additional collateral in the form of cash or letters of credit, certificates of deposit or other similar forms of liquid collateral. If we are required to provide additional collateral pursuant to any such request or otherwise, our liquidity position may be negatively impacted, and we may be required to seek alternative financing. To the extent we are unable to secure adequate financing, we may be forced to reduce our capital expenditures in the current year or future years, may be unable to execute our asset retirement obligation plan or may be unable to comply with our existing debt instruments. If we are unable or unwilling to provide additional collateral, we may have to pursue alternate bonding arrangements with other sureties. See Note 6, "Asset Retirement Obligations" and Note 16, "Commitments and Contingencies — Supplemental Bond for Decommissioning Liabilities Trust Agreement" of the Notes to Consolidated Financial Statements included under Part II, Item 8. Financial Statements and Supplementary Data, in this Annual Report for additional information.

Certain U.S. federal income tax deductions currently available with respect to oil and natural gas exploration and production may be eliminated as a result of future legislation.

In past years, legislation has been proposed that would, if enacted into law, make significant changes to U.S. tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, or IDCs, (iii) the elimination of the deduction for certain domestic production activities and (iv) an extension of the amortization period for certain geological and geophysical expenditures. Although these provisions were largely unchanged by the Tax Act, Congress could consider and could include some or all of these proposals as part of future tax reform legislation. It is unclear whether any of the foregoing or similar proposals will be considered and enacted as part of future tax reform legislation and if enacted, how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development and any such change could have an adverse effect on the Company's financial position, results of operations and cash flows.

Our business could be negatively affected by security threats, including cybersecurity threats, destructive forms of protest and opposition by activists and other disruptions.

As an oil and natural gas producer, we face various security threats, including cybersecurity threats to gain unauthorized access to sensitive information, to misappropriate financial assets or to render data or systems unusable; threats to the security of our facilities and infrastructure or third party facilities and infrastructure, such as processing plants and pipelines; and threats from terrorist acts. The potential for such security threats has subjected our operations to increased risks that could have a material adverse effect on our business. In particular, our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information, facilities and infrastructure may result in increased capital and operating costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. If any of these security breaches were to occur, they could lead to losses of financial assets, sensitive information, critical infrastructure or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations or cash flows. Cybersecurity attacks in particular are becoming more sophisticated and include, but are not limited to, malicious software, attempts to gain unauthorized access to data and systems, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information, and corruption of data. These events could lead to financial losses from remedial actions, loss of business or potential liability. In addition, destructive forms of protest and opposition by activists and other disruptions, including acts of sabotage or eco-terrorism, against oil and gas production and activities could potentially result in damage or injury to people, property or the environment or lead to extended interruptions of our operations, adversely affecting our financial condition and results of operations.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Information regarding our properties is contained in “Item 1. Business — Our Areas of Operation” and “—Our Oil and Natural Gas Data” and “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations —Results of Operations” contained herein.

ITEM 3. LEGAL PROCEEDINGS

Proceedings and Investigations relating to the Southern California Pipeline Incident

Amplify Energy Corp., Beta Operating Company, LLC d/b/a Beta Offshore, and San Pedro Bay Pipeline Company have been named as defendants in approximately 14 putative class action lawsuits related to the Incident and filed in the United States District Court for the Central District of California. On December 20, 2021 the putative class actions were consolidated into a single consolidated action in the United States District Court for the Central District of California. In the consolidated action, Plaintiffs filed an amended class action complaint on January 28, 2022. The amended complaint asserts claims against us for (1) Violations of the Lempert-Keene-Seastrand Oil Spill Prevention and Response Act, Gov. Code §8670, et seq.; (2) Lost Profits and Earning Capacity Damages (Federal Oil Pollution Act of 1990, §§ 1002, 1006); (3) Strict Liability for Ultrahazardous Activities; (4) Negligence; (5) Public Nuisance; (6) Negligent Interference with Prospective Economic Advantage; (7) Trespass; (8) Continuing Private Nuisance; and (9) Violations of California’s Unfair Competition Law (Cal. Bus. & Prof.Code §§ 17200, et seq.). The proposed classes are: (1) a class made up of persons or entities that owned or worked on a commercial fishing vessel, or sold commercial seafood, in the affected area; (2) owners or lessees of residential waterfront properties or residential properties with a private easement to the beach in the affected areas; and (3) persons or entities that owned or worked in certain waterfront tourism industries in the allegedly affected area. The amended complaint also asserts claims against MSC Mediterranean Shipping Company, Dordellas Finance Corp., Costamare Shipping Co. S.A., and Capetanissa Maritime Corporation of Liberia. The Company denies the allegations made against it and intends to vigorously defend against them. The parties are engaged in discovery and the Court has tentatively set trial for September 2023.

Under the Oil Pollution Act of 1990, 33 U.S.C. S 2701 et seq. (“OPA 90”), our pipeline was designated by the United States Coast Guard as the source of the oil discharge and therefore we are financially responsible for remediation and for certain costs and economic damages as provided for in OPA 90, as well as certain natural resource damages associated with the spill and certain costs determined by federal and state trustees engaged in a joint assessment of such natural resource damages. We are currently processing covered claims under OPA 90 as expeditiously as possible.

On February 28, 2022, we filed a third-party complaint in the United States District Court for the Central District of California against MSC Mediterranean Shipping Company, Dordellas Finance Corporation, Costamare Shipping Co. S.A., Capetanissa Maritime Corporation of Liberia, V.Ships Greece Ltd., the vessels MSC Danit and COSCO Beijing, those vessels' as-yet unknown captains and crews, and the Marine Exchange of Los Angeles-Long Beach Harbor d/b/a Marine Exchange of Southern California for damages and injunctive relief. Our complaint alleges that the actions and inactions of these parties caused and continue to cause Amplify significant harm and, without them, the Incident never would have happened. We seek contribution from these parties under OPA, damages for the harm caused to us, and injunctive relief requiring the Marine Exchange of Southern California to alert us and any other owners of undersea property of any and all potential anchor-dragging incidents in the area surrounding their undersea property within 24 hours of the incident and to not allow vessels to anchor in the anchorages located immediately adjacent to the Pipeline when heavy weather is likely. We may, in the future, seek contribution from any other third parties that are liable or potentially liable under OPA or any other law in connection with the Incident.

On February 28, 2022, we also filed a motion to dismiss certain claims from the plaintiffs' consolidated amended class action complaint in the United States District Court of the Central District of California. The motion seeks dismissal of the state law claims against Amplify because they are preempted by OPA or otherwise fail as a matter of law. The motion also asks the Court to enforce OPA by dismissing the claims of those plaintiffs who have not yet complied with OPA's requirements.

We are currently subject to a number of ongoing investigations related to the Incident by certain federal and state agencies. To date, the U.S. Coast Guard, the U.S. Bureau of Ocean Energy Management, the U.S. Department of Justice, the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration, the U.S. Department of the Interior Bureau of Safety and Environmental Enforcement, the California Department of Justice, the Orange County District Attorney, the Los Angeles County District Attorney, and the California Department of Fish & Wildlife are conducting investigations or examinations of the Incident. Other federal agencies may or have commenced investigations and proceedings, and federal agencies such as the U.S. Environmental Protection Agency may initiate enforcement actions seeking penalties and other relief under the Clean Water Act and other statutes. The outcomes of these investigations and the nature of any remedies pursued will depend on the discretion of the relevant authorities and may result in regulatory or other enforcement actions, as well as civil and criminal liability.

On December 15, 2021, a federal grand jury in the Central District of California returned a federal criminal indictment against Amplify Energy Corp., Beta Operating Company, LLC, and San Pedro Bay Pipeline Company in connection with the Incident. The indictment alleges that we committed a misdemeanor violation of the federal Clean Water Act for negligently discharging oil into the contiguous zone of the United States. The United States Attorney's Office for the Central District of California has stated that its investigation of the Incident and related matters is ongoing. State authorities are conducting parallel criminal investigations as well. We are continuing to cooperate with these federal and state investigations. The outcome of these investigations is uncertain, including whether they will result in additional criminal charges.

Our potential liabilities resulting from pending and future claims, lawsuits and enforcement actions relating to the Incident, together with the potential cost of implementing remedies sought in the various proceedings, cannot be fully estimated at this time but they may have a material adverse impact on our business, results of operations and financial condition and the implementation of our strategic agenda.

Other Legal Proceedings

As part of our normal business activities, we may be named as defendants in other litigation and legal proceedings, including those arising from regulatory and environmental matters. If we determine that a negative outcome is probable and the amount of loss is reasonably estimable, we accrue the estimated amount. We are not aware of any other litigation, pending or threatened, that we believe will have a material adverse effect on our financial position, results of operations or cash flows. No amounts have been accrued at December 31, 2021, in regard to our litigation and legal proceedings.

For additional information regarding legal proceedings, see Note 16, "Commitments and Contingencies — Litigation and Environmental" of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" of this Annual Report and "Part II – Item 1A. Risk Factors — Risks Related to the Southern California Pipeline Incident" which are incorporated herein by reference.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Market Information

Our Common Stock is listed on the NYSE under the trading symbol "AMPY" and has been trading since August 7, 2019.

As of February 28, 2022, we had 38,064,214 shares of our Common Stock outstanding. As of February 28, 2022, we had twenty-seven record holders of our Common Stock, based on information provided by our transfer agent.

Dividends Policy

While we may decide to pay cash dividends in the future, we have not paid, nor do we currently intend to pay, any cash dividends on our common stock. Future dividends, if any, are subject to debt covenants under our Revolving Credit Facility and discretionary approval by the board of directors.

Securities Authorized for Issuance Under Equity Compensation Plan

See the information incorporated by reference in "Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters" for information regarding shares of our common stock authorized for issuance under our stock compensation plans, which information is incorporated herein by reference.

Issuer Purchases of Equity Securities

The following sets forth information with respect to the Company's repurchases of shares of its Common Stock during the fourth quarter of 2021.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares That May Yet Be Purchased Under the Plans or Programs (1) (In thousands)
Common Shares Repurchased (1)				
October 1, 2021 - October 31, 2021	8,283	$ 5.75	—	n/a
November 1, 2021 - November 30, 2021	—	$ —	—	n/a
December 1, 2021 - December 31, 2021	—	$ —	—	n/a

(1) Common shares are generally net-settled by shareholders to cover the required withholding tax upon vesting. The Company repurchased the remaining vesting shares on the vesting date at current market price. See Note 11, "Equity-based Awards" of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" of this Annual Report, which is incorporated herein by reference.

ITEM 6. Reserved

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Management's Discussion and Analysis ("MD&A") of Financial Condition and Results of Operations should be read in conjunction with the financial statements and related notes in "Item 8. Financial Statements and Supplementary Data" contained herein. The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences are discussed in "Risk Factors" contained in Part I, Item 1A. of this report. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. See "Forward-Looking Statements" in the front of this Annual Report.

Overview

We operate in one reportable segment engaged in the acquisition, development, exploitation and production of oil and natural gas properties. Our management evaluates performance based on the reportable business segment as the economic environments are not different within the operation of our oil and natural gas properties. Our business activities are conducted through OLLC, our wholly owned subsidiary, and its wholly owned subsidiaries. Our assets consist primarily of producing oil and natural gas properties located in Oklahoma, the Rockies (Bairoil), federal waters offshore Southern California (Beta), East Texas/North Louisiana and Eagle Ford (Non-Op). Most of our oil and natural gas properties are located in large, mature oil and natural gas reservoirs.

Production and Operation Update

Our oil, natural gas and NGL production for the fiscal year 2021 decreased 14%, 13% and 17%, respectively from 2020. The decrease in production was attributable to Beta properties being shut in due to pipeline incident and natural decline. We had a 67% increase in oil and natural gas sales which was from higher realized oil, natural gas and NGL prices offset by lower production changes.

Our total estimated proved reserves increased to 121.2 MMBoe in 2021 compared to 113.8 MMBoe in 2020.

As of December 31, 2021, we are the operator of record for properties containing 92% of our total estimated proved reserves.

Impact of COVID-19

For a discussion of how COVID-19 has affected and may continue to affect our business and financial condition, see the discussion under the heading "Industry Trends" in Part I, Item 1 of this report, as well as the Risk Factors set forth in Part I, Item 1A of this report.

Recent Developments

Southern California Pipeline Incident

On October 2, 2021, contractors operating under the direction of Beta Operating Company, LLC ("Beta"), one of our subsidiaries, observed an oil sheen on the water approximately four miles off the coast of Newport Beach, California (the "Incident"). Beta platform personnel were notified and promptly initiated our Oil Spill Response Plan, which was reviewed and approved by the Bureau of Safety and Environmental Enforcement's Oil Spill Preparedness Division within the United States Department of the Interior, and which included the required notifications of specified regulatory agencies. On October 3, 2021, a Unified Command, consisting of the Company, the U.S. Coast Guard and California Department of Fish and Wildlife's Office of Spill Prevention and Response, was established to respond to the Incident.

On October 5, 2021, the Unified Command announced that reports from its contracted commercial divers and Remotely Operated Vehicle footage indicated that a 4,000-foot section of our pipeline had been displaced with a maximum lateral movement of approximately 105 feet and that the pipeline had a 13-inch split, running parallel to the pipe. On October 14, 2021, the U.S. Coast Guard announced that it had a high degree of confidence the size of the release was approximately 588 barrels of oil, which was below the previously reported maximum estimate of 3,134 barrels. On October 16, 2021, the U.S. Coast Guard announced that it had identified the Mediterranean Shipping Company (DANIT) as a “vessel of interest” and its owner Dordellas Finance Corporation and operator Mediterranean Shipping Company, S.A. as parties in interest in connection with an anchor-dragging incident in January 2021 (the “Anchor Dragging Incident”), which occurred in close proximity to our pipeline, and that additional vessels of interest continue to be investigated. On November 19, 2021, the U.S. Coast Guard announced that it had identified the COSCO (Beijing) as another vessel involved in the Anchor Dragging Incident and named its owner Capetanissa Maritime Corporation of Liberia and its operator V.Ships Greece Ltd. as parties in interest. The cause, timing and details regarding the Incident are currently under investigation and any information regarding the Incident is preliminary.

At the height of the Incident response, we deployed over 1,800 personnel working under the guidance and at the direction of the Unified Command to aid in cleanup operations. As of October 14, 2021, all beaches that had been closed following the Incident have reopened. On February 2, 2022, the Unified Command announced that response and monitoring efforts have officially concluded for the Incident, and Unified Command would stand down as of such date. Amplify is grateful to our Unified Command partners for their collaboration and professionalism over the course of the response.

In response to the Incident, all operations have been suspended and the pipeline has been shut-in until we receive the required regulatory approvals to begin operations. On October 4, 2021, the Pipeline and Hazardous Materials Safety Administration (“PHMSA”), Office of Pipeline Safety (“OPS”) issued a Corrective Action Order (“CAO”) pursuant to 49 U.S.C. § 60112, which makes clear that no restart of the affected pipeline may occur until PHMSA has approved a written restart plan. The California Coastal Commission has requested approval from the Office of Coastal Management for the National Oceanic and Atmospheric Association to conduct a Coastal Zone Management Act consistency review of the U.S. Army Corps of Engineers Nationwide Permit (“NWP”) 12 application for the proposed permanent repair permit. We are working expeditiously and cooperatively to comply with the requirements of the relevant agencies in order to gain such approvals and any other regulatory approvals that are necessary to permanently repair the pipeline and restart operations. As a result of the uncertainties related to the permitting and regulatory approval process, we can provide no assurances as to whether and when, if at all, we will be able to restart operations at the Beta field. At present no operations are underway in the Beta field.

We are currently subject to a number of ongoing investigations related to the Incident by certain federal and state agencies. To date, the U.S. Coast Guard, the U.S. Bureau of Ocean Energy Management, the U.S. Department of Justice, the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration, the U.S. Department of the Interior Bureau of Safety and Environmental Enforcement, the California Department of Justice, the Orange County District Attorney, the Los Angeles County District Attorney, and the California Department of Fish & Wildlife are conducting investigations or examinations of the Incident. Other federal agencies may or have commenced investigations and proceedings, and federal agencies such as the U.S. Environmental Protection Agency may initiate enforcement actions seeking penalties and other relief under the Clean Water Act and other statutes. Amplify continues to comply with all regulatory requirements and investigations. The outcomes of these investigations and the nature of any remedies pursued will depend on the discretion of the relevant authorities and may result in regulatory or other enforcement actions, as well as civil and criminal liability.

On December 15, 2021, a federal grand jury in the Central District of California returned a federal criminal indictment against Amplify Energy Corp., Beta Operating Company, LLC, and San Pedro Bay Pipeline Company in connection with the Incident. The indictment alleges that we committed a misdemeanor violation of the federal Clean Water Act for negligently discharging oil into the contiguous zone of the United States. The United States Attorney’s Office for the Central District of California has stated that its investigation of the Incident and related matters is ongoing. State authorities are conducting parallel criminal investigations as well. We are continuing to cooperate with these federal and state investigations. The outcome of these investigations is uncertain, including whether they will result in additional criminal charges.

We and certain of our subsidiaries have been named as defendants in approximately 14 putative class action lawsuits, which have been consolidated into a single consolidated action in the United States District Court for the Central District of California. In the consolidated action, Plaintiffs filed an amended class action complaint on January 28, 2022. The amended complaint asserted claims against us and MSC Mediterranean Shipping Company, Dordellas Finance Corp., Costamare Shipping Co. S.A., and Capetanissa Maritime Corporation of Liberia. Resolution of the consolidated case may take considerable time, and it is not possible at this time to estimate our potential liability resulting from these actions. For additional discussion of the legal proceedings associated with the Incident, see "Part I — Item 3. Legal Proceedings," "Part II — Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Part III — Item 1A. Risk Factors — Risks Related to the Southern California Pipeline Incident."

Under the Oil Pollution Act of 1990, 33 U.S.C. S 2701 et seq. ("OPA 90"), our pipeline was designated by the U.S. Coast Guard as the source of the oil discharge and therefore we are financially responsible for remediation and for certain costs and economic damages as provided for in OPA 90, as well as certain natural resource damages associated with the spill and certain costs determined by federal and state trustees engaged in a joint assessment of such natural resource damages. We are currently processing covered claims under OPA 90 as expeditiously as possible. In addition, the Natural Resource Damage Assessment remains ongoing and therefore the extent, timing and cost of related to such assessment are difficult to project. While we anticipate insurance will reimburse us for expenses related to the Natural Resource Damage Assessment, any potentially uncovered expenses may be material and could impact our business, our and results of operations and could put pressure on our liquidity position going forward.

We currently estimate that the total costs we have incurred or will incur with respect to the Incident related to (i) actual and projected response and remediation expenses incurred under the direction of the Unified Command and (ii) estimates for certain legal fees, to be approximately $90.0 million to $110.0 million. These estimates consider currently available facts and presently enacted laws and regulations. We have made assumptions regarding (i) the probable and estimable amounts expected to be settled with certain vendors for response and remediation expenses and (ii) the resolution of certain third-party claims, excluding claims with respect to losses, which are not probable and reasonably estimable, and (iii) future claims and lawsuits. Our estimates do not include (i) the nature, extent and cost of future legal services that will be required in connection with all lawsuits, claims and other matters requiring legal or expert advice associated with the Incident, (ii) any lost revenue associated with the suspension of operations at Beta, (iii) any liabilities or costs that are not reasonably estimable at this time or that relate to contingencies where we currently regard the likelihood of loss as being only reasonably possible or remote and (iv) the future costs associated with the permanent repair of the pipeline and the restart of the Beta operations. We believe we have accrued adequate amounts for all probable and reasonably estimable costs; however, this estimate is subject to uncertainties associated with the assumptions that we have made. For example, settlements with vendors for response and remediation expenses could turn out to be significantly higher or lower than we have estimated. Accordingly, our assumptions and estimates may change in future periods based on future events and total costs may materially increase; therefore, we can provide no assurance that we will not have to accrue significant additional costs in future periods with respect to the Incident.

In accordance with customary insurance practice, we maintain insurance policies, including loss of production income insurance, against many potential losses or liabilities arising from our operations and at costs that we believe to be economic. We regularly review our risk of loss and the cost and availability of insurance and revise our insurance accordingly. Our insurance does not cover every potential risk associated with our operations and is subject to certain exclusions and deductibles. While we expect our insurance policies will cover a material portion of the total aggregate costs associated with the Incident, including but not limited to response and remediation expenses, defense costs and loss of revenue resulting from suspended operations, we can provide no assurance that our coverage will adequately protect us against liability from all potential consequences, damages and losses related to the Incident and such view and understanding is preliminary and subject to change.

As of December 31, 2021, the Company has incurred total aggregate gross costs of $99.0 million, of which the Company has received or believes that it is probable that it will receive $97.4 million in insurance recoveries. The Company's net charge of $1.6 million, which is classified as "Pipeline Incident Loss" in the Company's Consolidated Statements of Operations, insurance deductibles and legal costs incurred to date that are not currently expected to be recovered under an insurance policy.

Through December 31, 2021, we had collected $48.3 million out of the approximate $97.4 million of costs that we believe are probable of recovery from insurance carriers, net of deductibles. Therefore, as of December 31, 2021, we have recognized a receivable of approximately $49.1 million for the portion of costs that we believe is probable of recovery from insurance, net of deductibles and amounts collected during 2021. Subsequent to December 31, 2021, for the period January 1, 2022 through March 1, 2022, we received insurance cost recoveries of $22.1 million

Additionally, during 2021, we recognized $6.7 million related to approved LOPI insurance claims, which is classified as "Other Revenues" in the Company's Consolidated Statement of Operations. Subsequent to December 31, 2021, for the period January 1, 2022 through March 1, 2022, we received the entire LOPI insurance claim settlement of $6.7 million. For additional discussion of the risks associated with the Incident, see "Item 1A. Risk Factors — Risks Related to the Southern California Pipeline Incident."

Business Environment and Operational Focus

We use a variety of financial and operational metrics to assess the performance of our oil and natural gas operations, including: (i) production volumes; (ii) realized prices on the sale of our production; (iii) cash settlements on our commodity derivatives; (iv) lease operating expense; (v) gathering, processing and transportation; (vi) general and administrative expense; and (vii) Adjusted EBITDA.

Production Volumes

Production volumes directly impact our results of operations. For more information about our volumes, see "— Results of Operations" below.

Realized Prices on the Sale of Oil and Natural Gas

We market our oil and natural gas production to a variety of purchasers based on regional pricing. The relative prices of oil and natural gas are determined by the factors impacting global and regional supply and demand dynamics, such as economic conditions, production levels, weather cycles and other events. In addition, realized prices are heavily influenced by product quality and location relative to consuming and refining markets.

Natural Gas. The NYMEX-Henry Hub future price of natural gas is a widely used benchmark for the pricing of natural gas in the United States. The actual prices realized from the sale of natural gas can differ from the quoted NYMEX-Henry Hub price as a result of quality and location differentials. Quality differentials to NYMEX-Henry Hub prices result from: (1) the Btu content of natural gas, which measures its heating value, and (2) the percentage of sulfur, CO_2 and other inert content by volume. Natural gas with a high Btu content ("wet" natural gas) sells at a premium to natural gas with low Btu content ("dry" natural gas) because it yields a greater quantity of NGLs. Natural gas with low sulfur and CO_2 content sells at a premium to natural gas with high sulfur and CO_2 content because of the added cost required to separate the sulfur and CO_2 from the natural gas to render it marketable. Wet natural gas may be processed in third-party natural gas plants, where residue natural gas as well as NGLs are recovered and sold. At the wellhead, our natural gas production typically has an average energy content greater than 1,000 Btu. The dry natural gas residue from our properties is generally sold based on index prices in the region from which it is produced.

Location differentials to NYMEX-Henry Hub prices result from variances in transportation costs based on the produced natural gas' proximity to the major consuming markets to which it is ultimately delivered. Historically, these index prices have generally been at a discount to NYMEX-Henry Hub natural gas prices.

Oil. The NYMEX-WTI futures price is a widely used benchmark in the pricing of domestic and imported oil in the United States. The ICE Brent futures price is a widely used global price benchmark for oil. The actual prices realized from the sale of oil can differ from the quoted NYMEX-WTI price as a result of quality and location differentials. Quality differentials result from the fact that crude oils differ from one another in their molecular makeup, which plays an important part in their refining and subsequent sale as petroleum products. Among other things, there are two characteristics that commonly drive quality differentials: (1) the oil's American Petroleum Institute ("API") gravity and (2) the oil's percentage of sulfur content by weight. In general, lighter oil (with higher API gravity) produces a larger number of lighter products, such as gasoline, which have higher resale value and, therefore, normally sells at a higher price than heavier oil. Oil with low sulfur content ("sweet" oil) is less expensive to refine and, as a result, normally sells at a higher price than high sulfur-content oil ("sour" oil).

Location differentials result from variances in transportation costs based on the produced oil's proximity to the major consuming and refining markets to which it is ultimately delivered. Oil that is produced close to major consuming and refining markets, such as near Cushing, Oklahoma, is in higher demand as compared to oil that is produced farther from such markets. Consequently, oil that is produced close to major consuming and refining markets normally realizes a higher price (i.e., a lower location differential).

The oil produced from our onshore properties is a combination of sweet and sour oil, varying by location. This oil is typically sold at the NYMEX-WTI price, adjusted for quality and transportation differential, depending primarily on location and purchaser. The oil produced from our Beta Properties is heavy and sour oil. Oil produced from our Beta Properties is currently sold based on refiners' posted prices for California Midway-Sunset deliveries in Southern California, adjusted primarily for quality and a negotiated market differential.

Price Volatility. In the past, oil and natural gas prices have been extremely volatile, and we expect this volatility to continue. The following table shows the low and high commodity future index prices for the periods indicated:

	High	Low
For the Year Ended December 31, 2021:		
NYMEX-WTI oil future price range per Bbl	$ 84.65	$ 47.62
NYMEX-Henry Hub natural gas future price range per MMBtu	$ 6.20	$ 2.45
ICE Brent oil future price range per Bbl	$ 86.40	$ 51.80
For the Five Years Ended December 31, 2021:		
NYMEX-WTI oil future price range per Bbl	$ 84.65	$ (37.63)
NYMEX-Henry Hub natural gas future price range per MMBtu	$ 6.20	$ 1.48
ICE Brent oil future price range per Bbl	$ 86.40	$ 19.33

Commodity Derivative Contracts. Our hedging activities are intended to support oil, natural gas and NGL prices at targeted levels and to manage our exposure to commodity price fluctuations. We intend to enter into commodity derivative contracts at times and on terms desired to maintain a portfolio of commodity derivative contracts covering at least 30% - 60% of our estimated production from proved developed producing reserves over a one-to-three-year period at any given point of time. We may, however, from time to time hedge more or less than this approximate range. Additionally, we may take advantage of opportunities to modify our commodity derivative portfolio to change the percentage of our hedged production volumes when circumstances suggest that it is prudent to do so. The current market conditions may also impact our ability to enter into future commodity derivative contracts.

Principal Components of Cost Structure

- *Lease operating expense*. These are the day to day costs incurred to maintain production of our natural gas, NGLs and oil. Such costs include utilities, direct labor, water injection and disposal, the cost of CO_2 injection, chemicals, materials and supplies, compression, repairs and workover expenses. Cost levels for these expenses can vary based on supply and demand for oilfield services and activities performed during a specific period.

- *Gathering, processing and transportation.* These are costs incurred to deliver production of our natural gas, NGLs and oil to the market. Cost levels of these expenses can vary based on the volume of natural gas, NGLs and oil production.

- *Taxes other than income*. These consist of production, ad valorem and franchise taxes. Production taxes are paid on produced natural gas, NGLs and oil based on a percentage of market prices and at fixed per unit rates established by federal, state or local taxing authorities. We take advantage of credits and exemptions in the various taxing jurisdictions where we operate. Ad valorem taxes are generally tied to the valuation of the oil and natural gas properties. Franchise taxes are privilege taxes levied by states that are imposed on companies, including limited liability companies and partnerships, which gives the businesses the right to be chartered or operate within that state.

- *Depreciation, depletion and amortization*. Depreciation, depletion and amortization ("DD&A") includes the systematic expensing of the capitalized costs incurred to acquire, exploit and develop oil and natural gas properties. As a "successful efforts" company all costs associated with acquisition and development efforts and all successful exploration efforts are capitalized, and these costs are depleted using the units of production method.

- *Impairment expense.* Proved properties are impaired whenever the net carrying value of the properties exceed their estimated undiscounted future cash flows. Unproved properties are impaired based on time or geologic factors.

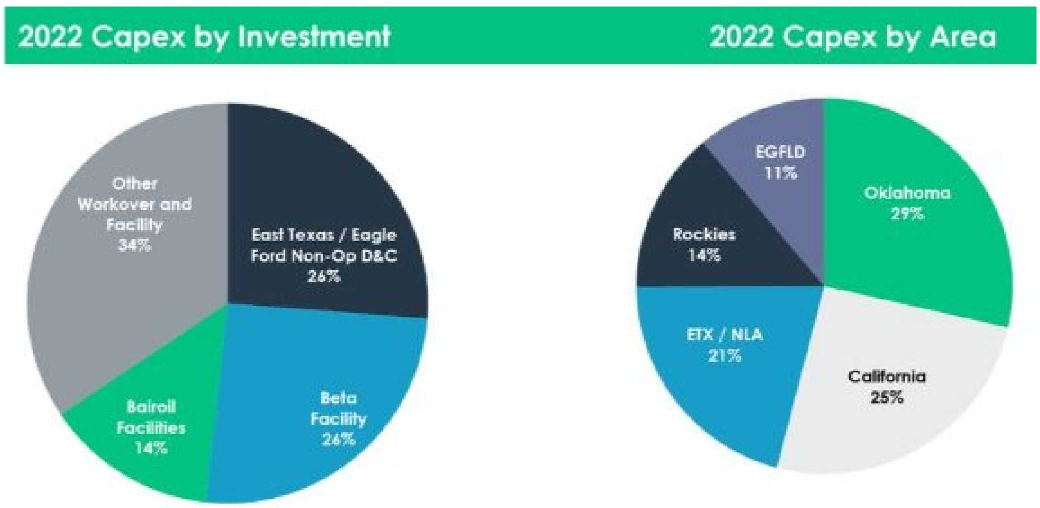
- *General and administrative expense*. These costs include overhead, including payroll and benefits for employees, costs of maintaining headquarters, costs of managing production and development operations, compensation expenses associated with certain long-term incentive-based plans, audit and other professional fees and legal compliance expenses.

- *Interest expense.* Historically, we financed a portion of our working capital requirements, capital development and acquisitions with borrowings under our Revolving Credit Facility. As a result, we incur substantial interest expense that is affected by both fluctuations in interest rates and financing decisions. We expect to continue to incur significant interest expense.

- *Income tax expense.* We are a corporation subject to federal and certain state income taxes. We are subject to the Texas margin tax for activities in the State of Texas.

Outlook

Based on our current plans, our capital expenditure program for the full year 2022 is expected to be approximately $20.0 million to $30.0 million. The charts below detail the allocation of capital across our asset base and by investment type based on the midpoint of our 2022 capital expenditure range.



As has been our historical practice, we will periodically review our capital expenditures throughout the year and may adjust the budget based on commodity prices and other factors. We anticipate funding our 2022 capital program from internally generated cash flow, borrowings under our Revolving Credit Facility and/or debt or equity financings may provide incremental financial flexibility.

Critical Accounting Policies and Estimates

The methods, estimates and judgments we use in applying our critical accounting policies have a significant impact on the results we report in our Consolidated Financial Statements. We evaluate our estimates and judgments on an on-going basis. We base our estimates on historical experience and on assumptions that we believe to be reasonable under the circumstances. Our experience and assumptions form the basis for our judgments about the carrying value of assets and liabilities that are not readily apparent from other sources. Actual results may vary from what we anticipate and different assumptions or estimates about the future could change our reported results. Within the context of these critical accounting policies, we are not currently aware of any reasonably likely event that would result in materially different amounts being reported.

Oil and Natural Gas Properties. We use the successful efforts method of accounting for our oil and natural gas properties. Under this method, costs of acquiring properties, costs of drilling successful exploration wells and development costs are capitalized. At the completion of drilling activities, the costs of exploratory wells remain capitalized if a determination is made that proved reserves have been found. If no proved reserves have been found, the costs of each of the related exploratory wells are charged to expense. See Note 2 of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" of this Annual Report for a discussion of the fair value measurements of our proved and unproved oil and natural gas properties and other long-lived assets.

We believe accounting for oil, natural gas, and NGLs properties is a critical accounting estimate because the evaluations of impairment of proved properties involve significant judgment about future events, such as future sales prices of natural gas and NGLs and future production costs, as well as the amount of natural gas and NGLs recorded and timing of recoveries. Significant changes in these estimates could result in the costs of our proved and unproved properties not being recoverable; therefore, we would be required to recognize an impairment.

***Oil and Natural Gas Reserves*.** Proved oil and natural gas reserves are estimated in accordance with the rules established by the SEC and FASB. The rules require that reserve estimates be prepared under existing economic and operating conditions using a trailing 12-month average price with no provision for price and cost escalation in future years except by contractual arrangements. Our reserve estimates are prepared by our reserve engineers and audited by independent engineers.

Our reserve estimates are updated at least annually using geological and reserve data, as well as production performance data. Reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. It is possible that, because of changes in market conditions or the inherent imprecision of reserve estimates, the estimates of future cash inflows, future gross revenues, the amount of oil and natural gas reserves, the remaining estimated lives of oil and natural gas properties, or any combination of the above may be increased or decreased. Increases in recoverable economic volumes generally reduce per unit depletion rates, while decreases in recoverable economic volumes generally increase per unit depletion rates. A decline in proved reserves may result from lower market prices, which may make it uneconomical to drill for and produce higher cost fields. In addition, a decline in proved reserve estimate may impact the outcome of our assessment of oil and natural gas producing properties for impairment. We cannot predict what reserve revisions may be required in future periods.

We believe oil and natural gas reserves is a critical accounting estimate because we must periodically reevaluate proved reserves along with estimates of future production rates, production costs and the timing of development expenditures. Future results of operations for any period could be materially affected by changes in our assumptions. Significant changes in these estimates could result in a change to our estimated reserves, which could lead to a material change to our production depletion expense.

Fair Value Estimates. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at a specified measurement date. Fair value estimates are based on either (i) actual market data or (ii) assumptions that other market participants would use in pricing an asset or liability, including estimates of risk. A three-tier hierarchy has been established that classifies fair value amounts recognized or disclosed in the financial statements. The hierarchy considers fair value amounts based on observable inputs (Levels 1 and 2) to be more reliable and predictable than those based primarily on unobservable inputs (Level 3).

Valuation techniques that maximize the use of observable inputs are favored. Assets and liabilities are classified in their entirety based on the lowest priority level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy. See Notes 4 of the Notes to Consolidated Financial Statements included under “Item 8. Financial Statements and Supplementary Data” of this Annual Report for a discussion of our fair value measurements.

We believe fair value estimates are a critical accounting estimate because the significance of a particular input to fair value measurements requires judgment and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. Significant uses of fair value measurements include: derivative instruments, asset retirement obligations (“ARO”), and impairment assessments of long-lived assets.

The carrying values of our cash and cash equivalents (Level 1), accounts receivables, accounts payables (including accrued liabilities) and amounts outstanding under long-term debt agreements with variable rates included in the accompanying balance sheets approximated fair value at December 31, 2021 and 2020.

Our commodity derivative financial instruments are used to reduce the impact of natural gas and oil price fluctuations. We record our derivative instrument in the balance sheet as either an asset or liability measured at its fair value. Changes in the derivative’s fair value are recognized currently in earnings as we have not elected hedge accounting for any of our derivative positions. Significant changes to the market value of derivative instruments due to the volatility of oil and natural gas prices can have an impact on our financial condition and results of operations.

The fair value of our AROs (Level 3) are based on discounted cash flow projections which uses numerous estimates and assumptions, and judgements regarding such factors as the existence of a legal obligation for an ARO, amounts and timing of settlements, credit-adjusted risk-free rate and inflation rates.

We review our assets for impairments annually or when events and circumstances indicate the carrying value of our properties may not be recoverable. This may be due to a downward revision of the reserve estimates, less than expected production or drilling results, higher operating and development costs, or lower commodity prices. If the carrying value of the property exceeds its estimated undiscounted future cash flows, the carrying amount of the property is reduced to its estimated fair value using Level 3 inputs. The factors used to determine fair value include, but are not limited to, estimates of proved and probable reserves, future commodity prices, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties.

Revenue Recognition. Our revenue is primarily derived from the sale of oil and natural gas production, as well as the sale of NGLs that are extracted from natural gas during processing. Revenue is recognized when the following five steps are completed: (1) identify the contract with the customer, (2) identify the performance obligation (promise) in the contract, (3) determine the transaction price, (4) allocate the transaction price to the performance obligations in the contract, (5) recognize revenue when the reporting organization satisfies a performance obligation.

Prices for natural gas, NGLs and oil sales are negotiated based on factors normally considered in the industry, such as index or spot price, distance from the well to the pipeline, commodity quality and prevailing supply and demand conditions. To the extent actual quantities and values of oil, NGLs 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 price for those properties must be estimated.

We believe revenue recognition is a critical accounting estimate because revenue is an essential portion of our results of operations.

Contingencies and Insurance Accounting. A provision for legal, environmental and other contingent matters is charged to expense when the loss is probable and the cost or range of cost can be reasonably estimated. Judgment is often required to determine when expenses should be recorded for legal, environmental and contingent matters. Although we are insured against various risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings.

Environmental costs for remediation are accrued when environmental remediation efforts are probable and the costs can be reasonably estimated. Such accruals are based on management's best estimate of the ultimate cost to remediate a site and are adjusted as further information and circumstances develop. Those estimates may change substantially depending on information about the nature and extent of contamination, appropriate remediation technologies and regulatory approvals.

An insurance receivable is recognized when collection of the receivable is deemed probable. Any recognition of an insurance receivable is recorded by crediting and offsetting the original charge. Any differential arising between the insurance recoveries and insurance receivables is recorded as a capitalized cost or as an expense, consistent with its original treatment.

We believe contingencies and insurance accounting is a critical accounting estimate because we must assess the probability of the loss related to the contingency and the expected amount that is covered by insurance. At December 31, 2021, we are not aware of any regulatory demands, fines or penalties of any dollar amount.

Results of Operations

The results of operations for the years ended December 31, 2021 and 2020, have been derived from our Consolidated Financial Statements.

The table below summarizes certain of the results of operations and period-to-period comparisons for the periods indicated.

	For the Year Ended December 31, 2021	2020
	($ In thousands)	
Oil and natural gas sales	$ 335,779	$ 200,888
Other revenues	7,137	1,256
Lease operating expense	121,398	119,708
Gathering, processing and transportation	20,807	20,547
Taxes other than income	22,250	12,944
Depreciation, depletion and amortization	28,068	40,268
Impairment expense	—	476,936
General and administrative expense	25,285	27,789
Accretion of asset retirement obligations	6,611	6,206
Loss (gain) on commodity derivative instruments	142,439	(60,671)
Interest expense, net	(12,099)	(20,522)
Gain on extinguishment of debt	5,516	—
Net loss	(32,070)	(464,030)
Oil and natural gas revenues:		
Oil sales	$ 212,486	$ 138,273
NGL sales	40,899	20,064
Natural gas sales	82,394	42,551
Total oil and natural gas revenues	$ 335,779	$ 200,888
Production volumes:		
Oil (MBbls)	3,351	3,887
NGLs (MBbls)	1,430	1,725
Natural gas (MMcf)	23,808	27,473
Total (MBoe)	8,747	10,190
Average net production (MBoe/d)	24.0	27.8
Average realized sales price (excluding commodity derivatives):		
Oil (per Bbl)	$ 63.43	$ 35.58
NGL (per Bbl)	28.62	11.63
Natural gas (per Mcf)	3.46	1.55
Total (per Boe)	$ 38.39	$ 19.71
Average unit costs per Boe:		
Lease operating expense	$ 13.88	$ 11.75
Gathering, processing and transportation	2.38	2.02
Taxes other than income	2.54	1.27
General and administrative expense	2.89	2.73
Depletion, depreciation and amortization	3.21	3.95

For the year ended December 31, 2021 compared to the year ended December 31, 2020

Net losses of $32.1 million and $464.0 million was recorded for the year ended December 31, 2021 and 2020, respectively.

Oil, natural gas and NGL revenues were $335.8 million and $200.9 million for the year ended December 31, 2021 and 2020, respectively. Average net production volumes were approximately 24.0 MBoe/d and 27.8 MBoe/d for the year ended December 31, 2021 and 2020, respectively. The change in production volumes was primarily due to natural decline, Beta properties shut-in starting in October 2021 and the impact of Winter Storm Uri that caused a severe freeze in areas where we operate, including Texas, Oklahoma and Louisiana, resulting in shut-ins for wells, pipelines and plants for approximately two weeks in February 2021. The average realized sales price was $38.39 per Boe and $19.71 per Boe for the year ended December 31, 2021 and 2020, respectively. The change in the average realized sales price was primarily due to the increase in realized commodity prices. Commodity prices were depressed in 2020 due to the impact of the pandemic and the effects of OPEC production related to supply and demand decisions.

Other revenues were $7.1 million and $1.3 million for the year ended December 31, 2021 and 2020, respectively. The change in other revenues was primarily related to us receiving loss of production income insurance of $6.7 million for the period of November 15, 2021 through December 31, 2021.

Lease operating expense was $121.4 million and $119.7 million for the year ended December 31, 2021 and 2020, respectively. The change in lease operating expense was primarily related to an increase for 2021 workover projects compared to 2020, partially offset by the employee retention credit received of $2.0 million for the first and second quarters of 2021. On a per Boe basis, lease operating expense was $13.88 and $11.75 for the year ended December 31, 2021 and 2020, respectively. The change in lease operating expense on a per Boe basis was primarily related to slightly higher costs and lower production.

Gathering, processing and transportation expenses were $20.8 million and $20.5 million for the year ended December 31, 2021 and 2020, respectively. The change in gathering, processing and transportation expenses was primarily driven by the decrease in production in the first quarter of 2021 from Winter Storm Uri, partially offset by additional fees from our non-operated wells and by fee increases from our processing plants and minimum volume commitments. On a per Boe basis, gathering, processing and transportation expenses were $2.38 and $2.02 for the year ended December 31, 2021 and 2020, respectively.

Taxes other than income was $22.3 million and $12.9 million for the year ended December 31, 2021 and 2020, respectively. The change in taxes other than income is due to an increase in production taxes as a result of the increase in commodity prices. On a per Boe basis, taxes other than income were $2.54 and $1.27 for the year ended December 31, 2021 and 2020, respectively. The change in taxes other than income on a per Boe basis was primarily due to an increase in commodity prices.

DD&A expense was $28.1 million and $40.3 million for the year ended December 31, 2021 and 2020, respectively. The change in DD&A expense was primarily due to a 14% decrease in production and a 19% decrease in our DD&A rate.

Impairment expense. No impairment expense was recorded for the year ended December 31, 2021. We recorded an impairment expense of $476.9 million for the year ended December 31, 2020. We recognized $427.6 million of impairment expense on proved properties for the year ended December 31, 2020. The estimated future cash flows expected from these properties were compared to their carrying values and determined to be unrecoverable primarily as a result of declining commodity prices. We recognized $49.3 million of impairment expense on unproved properties for the year ended December 31, 2020, which was related to expiring leases and the evaluation of qualitative and quantitative factors related to the current decline in commodity prices.

General and administrative expense was $25.3 million and $27.8 million for the year ended December 31, 2021 and 2020, respectively. The change in general and administrative expense is primarily related to (i) the employee retention credit received of $0.8 million for the first and second quarters of 2021; (ii) a decrease in professional services of $1.0 million, and (iii) a decrease in legal services of $0.8 million, offset with an increase of $1.2 million in stock compensation expense.

Net losses (gains) on commodity derivative instruments of $142.4 million were recognized for the year ended December 31, 2021, consisting of a $54.1 million decrease in the fair value of open positions and $88.3 million of cash settlements paid on expired positions. Net gains on commodity derivative instruments of $60.7 million were recognized for the year ended December 31, 2020, consisting of a $19.7 million decrease in the fair value of open positions offset by $62.4 million of cash settlements received on expired positions and $18.0 million of cash settlements received on terminated positions.

Given the volatility of commodity prices, it is not possible to predict future reported unrealized mark-to-market net gains or losses and the actual net gains or losses that will ultimately be realized upon settlement of the hedge positions in future years. If commodity prices at settlement are lower than the prices of the hedge positions, the hedges are expected to mitigate the otherwise negative effect on earnings of lower oil, natural gas and NGL prices. However, if commodity prices at settlement are higher than the prices of the hedge positions, the hedges are expected to dampen the otherwise positive effect on earnings of higher oil, natural gas and NGL prices and will, in this context, be viewed as having resulted in an opportunity cost.

Interest expense, net was $12.1 million and $20.5 million for the year ended December 31, 2021 and 2020, respectively. The change in interest expense is related to being in a gain position for interest rate swaps of $0.2 million for the year ended December 31, 2021 compared to being in a loss position of $4.0 million for the year ended December 31, 2020. Additionally, we had a decrease of $2.6 million in the amortization and write-off of deferred financing costs and a decrease of $1.4 million in interest expense due to lower outstanding borrowings.

Average outstanding borrowings under our Revolving Credit Facility were $240.2 million and $279.1 million for the year ended December 31, 2021 and 2020, respectively.

Gain on extinguishment of debt was $5.5 million for the year ended December 31, 2021, which is related to the forgiveness of the PPP Loan. See Note 8 of the Notes to Consolidated Financial Statements included under “Item 8. Financial Statements and Supplementary Data” of this Annual Report for additional information.

Adjusted EBITDA

We include in this report the non-GAAP financial measure Adjusted EBITDA and provide our calculation of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to net cash flow from operating activities, our most directly comparable financial measure calculated and presented in accordance with GAAP. Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of our consolidated financial statements, such as industry analysts, investors, lenders and rating agencies. Adjusted EBITDA is not a measure of net income or cash flows as determined by GAAP. We define Adjusted EBITDA as net income (loss):

Plus:

- Interest expense, including gains or losses on interest rate derivative contracts;
- Income tax expense;
- DD&A;
- Impairment of goodwill and long-lived assets (including oil and natural gas properties);
- Accretion of asset retirement obligations (“AROs”);
- Loss on commodity derivative instruments;
- Cash settlements received on expired commodity derivative instruments;
- Losses on sale of assets and other, net;
- Share-based compensation expenses;
- Exploration costs;
- Acquisition and divestiture related expenses;
- Amortization of gain associated with terminated commodity derivatives;

- Restructuring related costs;
- Reorganization items, net;
- Severance payments;
- Bad debt expense; and
- Other non-routine items that we deem appropriate.

Less:

- Interest income;
- Income tax benefit;
- Gain on extinguishment of debt
- Gain on expired commodity derivative instruments;
- Cash settlements paid on expired commodity derivative instruments;
- Gains on sale of assets and other, net; and
- Other non-routine items that we deem appropriate.

We are required to comply with certain Adjusted EBITDA-related metrics under our Revolving Credit Facility.

We believe that Adjusted EBITDA is useful because it allows us to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure.

Adjusted EBITDA should not be considered as an alternative to, or more meaningful than, net income or cash flows from operating activities as determined in accordance with GAAP or as an indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDA are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDA. Our computations of Adjusted EBITDA may not be comparable to other similarly titled measures of other companies. We believe that Adjusted EBITDA is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet debt service requirements.

In addition, management uses Adjusted EBITDA to evaluate actual cash flow, develop existing reserves or acquire additional oil and natural gas properties.

The following tables presents a reconciliation of the Company's net income (loss) and cash flows operating activities to Adjusted EBITDA, our most directly comparable GAAP financial measures, for each of the periods indicated.

Reconciliation of Net Income (Loss) to Adjusted EBITDA

	For the Year Ended December 31,	
	2021	2020
	(In thousands)	
Net loss	$ (32,070)	$ (464,030)
Interest expense, net	12,099	20,522
DD&A	28,068	40,268
Impairment expense	—	476,936
Accretion of AROs	6,611	6,206
Losses (gains) on commodity derivative instruments	142,439	(60,671)
Cash settlements received (paid) on expired commodity derivative instruments	(88,301)	62,389
Amortization of gain associated with terminated commodity derivatives	17,977	—
Share-based compensation expense	1,612	(177)
Gain on extinguishment of debt	(5,516)	—
Pipeline incident loss	1,599	—
Income tax expense	—	115
Acquisition and divestiture related expenses	19	1,092
Exploration costs	57	56
Loss on settlement of AROs	11	250
Bad debt expense	95	294
Non-cash inventory valuation adjustment	—	1,003
Secondary offering expenses	—	311
Reorganization items, net	6	566
Severance payments	—	57
Adjusted EBITDA	$ 84,706	$ 85,187

Reconciliation of Net Cash from Operating Activities to Adjusted EBITDA

	For the Year Ended December 31,	
	2021	2020
	(In thousands)	
Net cash provided by operating activities	$ 62,969	$ 74,330
Changes in working capital	(12,395)	10,661
Interest expense, net	12,099	20,522
Gain (loss) on interest rate swaps	217	(4,044)
Cash settlements paid (received) on interest rate swaps	1,912	1,254
Cash settlements paid (received) on terminated derivatives	—	(17,977)
Amortization of gain associated with terminated commodity derivatives	17,977	—
Pipeline incident loss	1,599	—
Amortization and write-off of deferred financing fees	(626)	(3,272)
Acquisition and divestiture related expenses	19	1,092
Income tax expense - current portion	—	115
Exploration costs	57	56
Plugging and abandonment cost	307	577
Reorganization items, net	6	566
Severance payments	—	57
Non-cash inventory valuation adjustment	—	1,003
Other	565	247
Adjusted EBITDA	$ 84,706	$ 85,187

Liquidity and Capital Resources

Overview. Our ability to finance our operations, including funding capital expenditures and acquisitions, to meet our indebtedness obligations, to refinance our indebtedness or to meet our collateral requirements will depend on our ability to generate cash in the future. Our primary sources of liquidity and capital resources have historically been cash flows generated by operating activities, borrowings under our Revolving Credit Facility, and equity and debt capital markets. As we pursue reserve and production growth, we plan to monitor which capital resources, including equity and debt financings, are available to us to meet our future financial obligations, planned capital expenditure activities and liquidity requirements. Based on our current oil and natural gas price expectations, we believe our cash flows provided by operating activities and availability under our Revolving Credit Facility will provide us with the financial flexibility necessary to meet our cash requirements, including normal operating needs, and to pursue our currently planned 2022 development activities. However, future cash flows are subject to a number of variables, including the level of our oil and natural gas production and the prices we receive for our oil and natural gas production, and significant additional capital expenditures will be required to more fully develop our properties. We cannot assure you that operations and other needed capital will be available on acceptable terms, or at all. We anticipate funding our 2022 capital program from internally generated cash flow, borrowings under our Revolving Credit Facility and/or debt or equity financings may provide incremental financial flexibility.

Impact of the Southern California Pipeline Incident. There is substantial uncertainty surrounding the full impact that the Incident will have on our financial condition and cash flow generation going forward. We have incurred and will continue to incur costs as a result of the Incident, and we anticipate that the suspension of production from Beta will lead to a material reduction in revenue from these assets. Although we carry customary insurance policies, including loss of production income insurance, which we expect will cover a material portion of the total aggregate costs associated with the Incident, including loss of revenue resulting from suspended operations, we can provide no assurance that our coverage will adequately protect us against liability from all potential consequences, damages and losses related to the Incident.

Capital Markets. We do not currently anticipate any near-term capital markets activity, but we will continue to evaluate the availability of public debt and equity for funding potential future growth projects and acquisition activity.

Hedging. Commodity hedging has been and remains an important part of our strategy to reduce cash flow volatility. Our hedging activities are intended to support oil, NGL and natural gas prices at targeted levels and to manage our exposure to commodity price fluctuations. We intend to enter into commodity derivative contracts at times and on terms desired to maintain a portfolio of commodity derivative contracts covering at least 30% - 60% of our estimated production from total proved developed producing reserves over a one-to-three-year period at any given point of time. We may, however, from time to time, hedge more or less than this approximate amount. Additionally, we may take advantage of opportunities to modify our commodity derivative portfolio to change the percentage of our hedged production volumes when circumstances suggest that it is prudent to do so. The current market conditions may also impact our ability to enter into future commodity derivative contracts.

We evaluate counterparty risks related to our commodity derivative contracts and trade credit. Should any of these financial counterparties not perform, we may not realize the benefit of some of our hedges under lower commodity prices. We sell our oil and natural gas to a variety of purchasers. Non-performance by a customer could also result in losses.

Capital Expenditures. Our total capital expenditures were approximately $30.9 million for the year ended December 31, 2021, which were primarily related to capital workovers and capital facilities expenditures located in the Rockies, Oklahoma and California and non-operated drilling activity in Eagle Ford.

Working Capital. Working capital is the amount by which current assets exceed current liabilities. Our working capital requirements are primarily driven by changes in accounts receivable and accounts payable as well as the classification of our debt outstanding. These changes are impacted by changes in the prices of commodities that we buy and sell. In general, our working capital requirements increase in periods of rising commodity prices and decrease in periods of declining commodity prices. However, our working capital needs do not necessarily change at the same rate as commodity prices because both accounts receivable and accounts payable are impacted by the same commodity prices. In addition, the timing of payments received by our customers or paid to our suppliers can also cause fluctuations in working capital because we settle with most of our larger customers on a monthly basis and often near the end of the month. We expect that our future working capital requirements will be impacted by these same factors.

As of December 31, 2021, we had a working capital deficit of $39.4 million primarily as the result of (i) a short-term derivative liability balance of $53.1 million (ii) an accrued liabilities balance of $57.8 million (iii) an accounts payable balance of $33.8 million, and (iv) a revenue payable balance of $20.4 million, less (i) an accounts receivable balance of $92.0 million, (ii) prepaid expenses and other current assets balance of $15.0 million and (iii) a cash balance of $18.8 million.

Debt Agreements

Revolving Credit Facility. On November 2, 2018, OLLC as borrower, entered into the Revolving Credit Facility (as amended and supplemented to date) with Bank of Montreal, as administrative agent. At December 31, 2021, our borrowing base under our Revolving Credit Facility was subject to redetermination on at least a semi-annual basis primarily based on a reserve engineering report. The borrowing base as of December 31, 2021, was $245.0 million.

As of December 31, 2021, we were in compliance with all the financial (current ratio and total leverage ratio) and non-financial covenants associated with our Revolving Credit Facility.

As of December 31, 2021, we had approximately $15.0 million of available borrowings under our Revolving Credit Facility.

On November 10, 2021, we completed our scheduled semi-annual borrowing base redetermination process, pursuant to which the borrowing base under our Revolving Credit Facility was reaffirmed at $245.0 million; provided that, beginning on February 28, 2022, the borrowing base will be reduced by $5.0 million per month on the last calendar day of each month until the next regularly scheduled redetermination, which is expected to occur in April 2022. This impact on our borrowing base may limit our liquidity position and may impact our ability to finance our operations.

On June 16, 2021, we completed our scheduled semi-annual borrowing base redetermination process, pursuant to which the borrowing base under our Revolving Credit Facility was decreased from $260.0 million to $245.0 million. Additionally, the administrative agent under our Revolving Credit Facility was changed from Bank of Montreal to KeyBank.

For additional information regarding our Revolving Credit Facility, see Note 8 of the Notes to Consolidated Financial Statements included under “Item 8. Financial Statements and Supplementary Data” of this Annual Report for additional information.

COVID-19 Relief Funding. On June 22, 2021, we were notified by the bank that our PPP Loan was approved for full and complete forgiveness by the Small Business Association. For the year ended December 31, 2021, we recorded a gain on extinguishment of debt for $5.5 million in our Consolidated Statements of Operations.

Under the Consolidated Appropriations Act 2021 passed by the U.S. Congress and signed by the President on December 27, 2020, provisions of the CARES Act were extended and modified, making us eligible for the employee retention credit subject to meeting certain criteria. We met the criteria for the first and second quarters of 2021 and recognized a $2.8 million employee retention credit during the year ended December 31, 2021, which is included as a credit to general and administrative expense and to lease operating expense in our Consolidated Statements of Operations.

Material Cash Requirements

Contractual commitments. We have contractual commitments under our debt agreements, including interest payments and principal payments. See Note 8 of the Notes to Consolidated Financial Statements included under “Item 8. Financial Statements and Supplementary Data” of this Annual Report for additional information.

Lease Obligations. We have operating leases for office and warehouse spaces, office equipment, compressors and surface rentals related to our business obligations. As of December 31, 2021, our future commitments under these contracts were $5.3 million in 2022, $1.2 million in 2023, $1.5 million in 2024, $1.5 million in 2025, $1.5 million in 2026 and $4.1 million thereafter. See Note 12 of the Notes to Consolidated Financial Statements included under “Item 8. Financial Statements and Supplementary Data” of this Annual Report for additional information.

Sinking fund payments. We have a funding requirement to fund a trust account to comply with supplemental regulatory bonding requirements related to our decommissioning obligations for our offshore Southern California production facilities. As of December 31, 2021, our future commitment under this agreement were $6.7 million in 2022, $8.0 million in 2023, $15.8 million in years 2024, $15.8 million in years 2025, $15.8 million in years 2026 and $110.5 million thereafter. See Note 16 of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" of this Annual Report for additional information.

Cash Flows from Operating, Investing and Financing Activities

The following table summarizes our cash flows from operating, investing and financing activities for the periods indicated. The cash flows for the years ended December 31, 2021 and 2020, have been derived from our Consolidated Financial Statements. For information regarding the individual components of our cash flow amounts, see the Statements of Consolidated Cash Flows included under "Item 8. Financial Statements and Supplementary Data" contained herein.

	For the Year Ended December 31,	
	2021	2020
	(In thousands)	
Net cash provided by operating activities	$ 62,969	$ 74,330
Net cash used in investing activities	(29,428)	(35,890)
Net cash used in financing activities	(25,106)	(28,401)

For the year ended December 31, 2021 compared to the year ended December 31, 2020

Operating Activities. Key drivers of net operating cash flows are commodity prices, production volumes and operating costs. Net cash provided by operating activities was $63.0 million and $74.3 million for the year ended December 31, 2021 and 2020, respectively. Production volumes decreased to 24.0 MBoe/d in 2021 from 27.8 MBoe/d in 2020 and the average realized sales price increased to $38.39 per Boe in 2021 from $19.71 per Boe in 2020. The changes in production and average realized sales price were primarily related to decreased drilling activities and increased commodity prices.

Net cash provided by operating activities for the year ended December 31, 2021 included $90.2 million of cash paid on expired derivative instruments compared to $61.1 million of cash receipts on expired derivative instruments and $18.0 million of cash receipts on terminated derivative instruments for the year ended December 31, 2020. For the year ended December 31, 2021, we had net losses on commodity derivative instruments of $142.4 million compared to net gains of $60.7 million for the year ended December 31, 2020.

In addition, we recorded a $5.5 million gain on extinguishment of debt related to the forgiveness of the PPP Loan. See Note 8 of the Notes to the Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" for additional information regarding the PPP Loan.

Investing Activities. Net cash used in investing activities for the year ended December 31, 2021 was $29.4 million, of which $29.3 million was used for additions to oil and gas properties. Net cash used in investing activities for the year ended December 31, 2020, was $35.9 million, of which $34.8 million was used for additions to oil and gas properties.

Financing Activities. We had net repayments of $25.0 million and $30.0 million under our Revolving Credit Facility for the year ended December 31, 2021 and 2020, respectively.

We received a $5.5 million loan under the Paycheck Protection Program on April 24, 2020. As noted above, we received complete forgiveness for the PPP loan received.

We paid out dividends of $3.8 million on March 30, 2020 to stockholders on record at the close of business on March 16, 2020. The board of directors subsequently suspended quarterly dividends. Future dividends, if any, are subject to debt covenants under our Revolving Credit Facility and discretionary approval by the board of directors.

For the year ended December 31, 2020 compared to the year ended December 31, 2019

Information related to the comparison of our discussion of the cash flows for the year ended December 31, 2020 compared to the year ended December 31, 2019, is included in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources" of our 2020 Form 10-K filed with the SEC and is incorporated by reference into this Annual Report on Form 10-K.

Capital Requirements

See "— Outlook" for additional information regarding our capital spending program for 2022.

Recently Issued Accounting Pronouncements

For a discussion of recent accounting pronouncements that will affect us, see Note 2 of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data."

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are a smaller reporting company as defined by Rule 12b-2 of the Exchange Act and are not required to provide the information under this item.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Our Consolidated Financial Statements, together with the report of our independent registered public accounting firm, begin on page F-1 of this Annual Report and are incorporated herein by reference.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures.

As required by Rules 13a-15(b) and 15d-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including the principal executive officer and principal financial officer of the Company, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) and under the Exchange Act) as of the end of the period covered by this Annual Report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including the principal executive officer and principal financial officer of the Company, as appropriate, to allow timely decisions regarding required disclosure, and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon this evaluation, the principal executive officer and principal financial officer of the Company have concluded that our disclosure controls and procedures were effective at the reasonable assurance level as of December 31, 2021.

Management's Report on Internal Control Over Financial Reporting

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act. Internal control over financial reporting, no matter how well designed, has inherent limitations. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements.

Under the supervision and with the participation of the Company's management, including the principal executive officer and principal financial officer of the Company, the Company assessed the effectiveness of its internal control over financial reporting based on the framework in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO Framework"). Based on this assessment, the Company's management, including its principal executive and financial officers, concluded that the Company's internal control over financial reporting was effective as of December 31, 2021 based on the criteria set forth under the COSO Framework.

Deloitte & Touche LLP, the independent registered public accounting firm who audited the Company's Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" in this Annual Report, has issued an attestation report on the effectiveness of the Company's internal control over financial reporting as of December 31, 2021. The report, which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting as of December 31, 2021, is contained herein under the heading "Report of Independent Registered Public Accounting Firm."

Changes in Internal Controls Over Financial Reporting

No changes in our internal control over financial reporting occurred during the quarter ended December 31, 2021 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

The certifications required by Section 302 of the Sarbanes-Oxley Act of 2002 are filed as exhibits 31.1 and 31.2 to this Annual Report.

Report of Independent Registered Public Accounting Firm

The Stockholders and Board of Directors

Amplify Energy Corp.:

Opinion on Internal Control Over Financial Reporting

We have audited the internal control over financial reporting of Amplify Energy Corp. and subsidiaries (the "Company") as of December 31, 2021, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2021, of the Company and our report dated March 9, 2022, expressed an unqualified opinion on those financial statements and financial statement schedule.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 9, 2022

ITEM 9B. OTHER INFORMATION

In consultation with the compensation committee's independent compensation consultant, the compensation committee reviewed our executive officers' compensation packages and approved adjustments for the following executive officers on March 7, 2022: (i) Martyn Willsher's annual base salary increased to $500,000 (from $350,000); (ii) Jason McGlynn's annual base salary increased to $350,000 (from $290,000); (iii) Tony Lopez's annual base salary increased to $310,000 (from $270,000) and his discretionary bonus compensation target percentage increased to 70% of annual base salary (from 60% of annual base salary); and (iv) Eric Willis's discretionary bonus compensation target percentage increased to 70% of annual base salary (from 65% of annual base salary).

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

None

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this item is incorporated herein by reference to the Company's definitive proxy statement relating to the 2022 Annual Meeting of Stockholders of Amplify Energy Corp. (the "Proxy Statement") to be held on May 17, 2022.

The Company's Code of Business Conduct and Ethics (the "Code of Ethics") can be found on the Company's website located at http://investor.amplifyenergy.com/corporate-governance. Any stockholder may request a printed copy of the Code of Ethics by submitting a written request to the Company's Corporate Secretary. If the Company amends the Code of Ethics or grants a waiver, including an implicit waiver, from the Code of Ethics, the Company will disclose the information on its website. The waiver information will remain on the website for at least 12 months after the initial disclosure of such waiver.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item is incorporated herein by reference to the Proxy Statement.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this item is incorporated herein by reference to the Proxy Statement.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this item is incorporated herein by reference to the Proxy Statement.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this item is incorporated herein by reference to the Proxy Statement.

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PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a)(1) *Financial Statements*

Our Consolidated Financial Statements are included under Part II, "Item 8. Financial Statements and Supplementary Data" of the Annual Report. For a listing of these statements and accompanying footnotes, see *"Index to Financial Statements"* on page F-1 of this Annual Report.

(a)(2) *Financial Statement Schedules*

All schedules have been omitted because they are either not applicable, not required or the information called for therein appears in the consolidated financial statements or notes thereto.

(a)(3) *Exhibits*

The exhibits listed on the Exhibit Index below are filed or incorporated by reference as part of this report, and such Exhibit Index is incorporated herein by reference.

Exhibit Index

Exhibit Number	Description
2.1	— Agreement and Plan of Merger, dated May 5, 2019, by and among Amplify Energy Corp., Midstates Petroleum Company, Inc. and Midstates Holdings, Inc. (incorporated by reference to Exhibit 2.1 of the Company's Current Report on Form 8-K (File No. 001-35364) filed on May 6, 2019).
3.1	— Second Amended and Restated Certificate of Incorporation of Midstates Petroleum Company, Inc. (filed as Exhibit 3.1 to the Company's Registration Statement on Form 8-A filed on October 21, 2016, and incorporated herein by reference).
3.2	— Certificate of Amendment to the Second Amended and Restated Certificate of Incorporation of Midstates Petroleum Company, Inc., dated August 6, 2019 (incorporated by reference to Exhibit 3.1 of the Company's Current Report on Form 8-K (File No. 001-35512) filed on August 6, 2019).
3.3	— Third Amended and Restated Bylaws of Amplify Energy Corp. (incorporated by reference to Exhibit 3.3 of the Company's Quarterly Report on Form 10-Q (File No. 001-35512) filed on November 15, 2021).
4.1	— Description of the Company's Capital Stock Registered Under Section 12 of the Securities Exchange Act of 1934 (incorporated by reference to Exhibit 4.3 to Annual Report on Form 10-K (File No. 0001-35512) filed on March 5, 2020).
10.1	— Amplify Energy Corp. Amended and Restated Registration Rights Agreement, dated August 6, 2019, between the Company and certain holders party thereto (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File No. 001-35512) filed on August 6, 2019).
10.2	— Warrant Agreement between Legacy Amplify, as Issuer, and American Stock Transfer & Trust Company, LLC, as Warrant Agent, dated as of May 4, 2017 (incorporated by reference to Exhibit 10.4 of Legacy Amplify's Current Report on Form 8-K (File No. 001-35364) filed on May 5, 2017).
10.3	— Form of 2019 RSU Award Agreement (Executives) (incorporated by reference to Exhibit 10.21 of the Company's Current Report on Form 8-K (File No. 001-35512) filed on August 6, 2019).
10.4	— Form of 2019 RSU Award Agreement (incorporated by reference to Exhibit 10.22 of the Company's Current Report on Form 8-K (File No. 001-35512) filed on August 6, 2019).

Exhibit Number	Description
10.5	— Form of Stock Option Award Agreement (incorporated by reference to Exhibit 99.2 of Legacy Amplify's Registration Statement on Form S-8 (File No. 333-217674) filed on May 4, 2017).
10.6#	— Amplify Energy Corp. Management Incentive Plan (incorporated by reference to Exhibit 99.1 of Legacy Amplify's Registration Statement on Form S-8 (File No. 333-217674) filed on May 4, 2017).
10.7	— Credit Agreement, dated as of November 2, 2018, among Amplify Energy Operating LLC, Amplify Acquisitionco. Inc., as parent, Bank of Montreal, as administrative agent and an L/C issuer, and the other lenders and agents from time to time party thereto (incorporated by reference to Exhibit 10.2 of Quarterly Report on Form 10-Q (File No. 001-35364) filed on November 7, 2018).
10.8	— Letter Agreement, dated as of December 21, 2018, among Amplify Energy Operating LLC, Amplify Acquisitionco, Inc., as parent, Bank of Montreal, as administrative agent and L/C issuer, and the other lenders and agents from time to time party thereto (incorporated by reference to Exhibit 10.21 to Legacy Amplify's Annual Report on Form 10-K (File No. 001-35364) filed on March 6, 2019).
10.9	— First Amendment to Credit Agreement, dated May 5, 2019, by and among Amplify Energy Operating LLC, Amplify Acquisitionco Inc., Legacy Amplify, the guarantors party thereto, lenders party thereto and Bank of Montreal, as administrative agent (incorporated by reference to Exhibit 10.1 of Legacy Amplify's Current Report on Form 8-K (File No. 001-35364) filed on May 6, 2019).
10.10	— Second Amendment to Credit Agreement, dated July 16, 2019, by and among Amplify Energy Operating LLC, Amplify Acquisitionco Inc., Legacy Amplify, the guarantors party thereto, lenders party thereto and Bank of Montreal, as administrative agent (incorporated by reference to Exhibit 10.1 of Legacy Amplify's Current Report on Form 8-K (File No. 001-35364) filed on July 17, 2019).
10.11	— Borrowing Base Redetermination, Commitment Increase and Joinder Agreement to Credit Agreement, dated August 6, 2019, by and among Amplify Energy Operating LLC, Amplify Acquisitionco LLC, the guarantors party thereto, the lenders party thereto and Bank of Montreal, as administrative agent (incorporated by reference to Exhibit 10.7 of Legacy Amplify's Current Report on Form 8-K (File No. 001-35512) filed on August 6, 2019).
10.12#	— Borrowing Base Redetermination Agreement and Third Amendment to Credit Agreement, dated June 12, 2020, by and among Amplify Energy Operating LLC, Amplify Acquistionco, Inc., the guarantors party thereto, Bank of Montreal, as administrative agent, and the other lenders and agents from time to time party thereto (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File No. 001-35512) filed on June 15, 2020).
10.13	— Borrowing Base Redetermination Agreement and Fourth Amendment to Credit Agreement, dated November 17, 2020, by and among Amplify Energy Operating LLC, Amplify Acquisitionco LLC, the guarantors party thereto, Bank of Montreal, as administrative agent, and the other lenders and agents from time to time party thereto (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File No. 001-35512) filed on November 18, 2020).
10.14	— Borrowing Base Redetermination Agreement and Fifth Amendment to Credit Agreement, dated as of November 10, 2021, by and among Amplify Energy Operating LLC, Amplify Acquisitionco LLC, each of the guarantors party thereto, each of the lenders party thereto and KeyBank National Association, as administrative agent for the lenders (incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q (File No. 001-35512) filed on November 15, 2021.
10.15#	— Amplify Energy Corp. 2017 Non-Employee Directors Compensation Plan (incorporated by reference to Exhibit 99.1 of Legacy Amplify's Registration Statement on Form S-8 (File No. 333-218745) filed on June 14, 2017).
10.16#	— Form of 2021 TRSU Award Agreement (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q (File No.001-35512) filed on May 5, 2021).

Exhibit Number		Description
10.17#	—	Form of 2021 PRSU Award Agreement (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q (File No.001-35512) filed on May 5, 2021).
10.18#	—	Employment Agreement, dated May 3, 2019, by and between Legacy Amplify and Martyn Willsher (incorporated by reference to Exhibit 10.1 to Legacy Amplify's Quarterly Report on Form 10-Q (File No. 001-35364) filed on May 9, 2019).
10.19#	—	Employment Agreement, dated May 3, 2019, by and between Legacy Amplify and Richard P. Smiley (incorporated by reference to Exhibit 10.2 to Legacy Amplify's Quarterly Report on Form 10-Q (File No. 001-35364) filed on May 9, 2019).
10.20#	—	Employment Agreement, dated May 3, 2019, by and between Legacy Amplify and Eric M. Willis (incorporated by reference to Exhibit 10.3 to Legacy Amplify's Quarterly Report on Form 10-Q (File No. 001-35364) filed on May 9, 2019).
10.21#	—	Employment Agreement, dated May 1, 2019, by and between Legacy Amplify and Tony Lopez (incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q (File No.001-35512) filed on May 6, 2020).
10.22#	—	Employment Agreement, dated February 3, 2020, by and between Amplify Energy Corp. and Jason McGlynn (incorporated by reference to Exhibit 10.26 of the Company's Annual Report on Form 10-K (File No.001-35512) filed on March 11, 2021).
10.23#	—	Employment Agreement, dated May 17, 2021, by and between Amplify Energy Corp. and Eric Dulany (incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q (File No. 001-35512) filed on August 4, 2021).
10.24	—	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.16 of the Company's Current Report on Form 8-K (File No. 001-35512) filed on August 6, 2019).
21.1*	—	List of Subsidiaries of Amplify Energy Corp.
23.1*	—	Consent of Cawley, Gillespie and Associates, Inc.
23.2*	—	Consent of Deloitte & Touche LLP
31.1*	—	Certification of Chief Executive Officer Pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934
31.2*	—	Certification of Chief Financial Officer Pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934
32.1*	—	Certifications of Chief Executive Officer and Chief Financial Officer pursuant to 18. U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	—	Report of Cawley, Gillespie and Associates, Inc.
101.INS*	—	Inline XBRL Instance Document
101.SCH*	—	Inline XBRL Schema Document
101.CAL*	—	Inline XBRL Calculation Linkbase Document
101.DEF*	—	Inline XBRL Definition Linkbase Document
101.LAB*	—	Inline XBRL Labels Linkbase Document
101.PRE*	—	Inline XBRL Presentation Linkbase Document

Exhibit Number	Description
104*	— Cover Page Interactive Data File (embedded within the Inline XBRL document)

* Filed or furnished as an exhibit to this Annual Report on Form 10-K.

\# Management contract or compensatory plan or arrangement.

\## Pursuant to Item 601(b)(2) of Regulation S-K, the registrant agrees to furnish supplementally a copy of any omitted exhibit or schedule to the SEC upon request.

ITEM 16. Form 10-K Summary

None.

SIGNATURES

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

Amplify Energy Corp.
(Registrant)

Date: March 9, 2022

By: /s/ Jason McGlynn
Name: Jason McGlynn
Title: Senior Vice President and Chief Financial Officer

Pursuant to the requirements of the Exchange Act, this report has been signed below by the following persons on behalf of the registrant and in their capacities and on the dates indicated.

Name	Title (Position with Amplify Energy Corp.)	Date
/s/ Martyn Willsher Martyn Willsher	President and Chief Executive Officer (Principal Executive Officer)	March 9, 2022
/s/ Jason McGlynn Jason McGlynn	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	March 9, 2022
/s/ Eric Dulany Eric Dulany	Vice President and Chief Accounting Officer (Principal Accounting Officer)	March 9, 2022
/s/ Christopher W. Hamm Christopher W. Hamm	Chairman and Director	March 9, 2022
/s/ Patrice Douglas Patrice Douglas	Director	March 9, 2022
/s/ Randal T. Klein Randal T. Klein	Director	March 9, 2022
/s/ Todd R. Snyder Todd R. Snyder	Director	March 9, 2022

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

AMPLIFY ENERGY CORP.
INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Amplify Energy Corp.:

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Amplify Energy Corp. and subsidiaries (the "Company") as of December 31, 2021 and 2020, the related consolidated statements of operations, stockholders' equity, and cash flows, for each of the two years in the period ended December 31, 2021, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2021 and 2020, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2021, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 9, 2022, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

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

Oil and Gas Reserve Quantities & Related Undiscounted Cashflows as used in the calculation of DD&A and Impairment — Refer to Notes 2 and 18 to the financial statements

Critical Audit Matter Description

The Company's proved oil and natural gas properties are reviewed for impairment when events and circumstances indicate the carrying value of such properties may not be recoverable. The estimated undiscounted future cash flows expected in connection with the property are compared to the carrying value of the property to determine if the carrying amount is recoverable. Depletion of capitalized costs is provided using the units-of-production method based on proved oil and natural gas reserves related to the associated field. The development of the Company's oil and natural gas reserve quantities require management to make significant estimates and assumptions. The Company engages an independent reservoir engineer, management's specialist, to estimate oil and natural gas quantities using generally accepted methods, calculation procedures and engineering data. Changes in assumptions or engineering data could have a significant impact on the amount of depletion. Proved oil and natural gas properties were $319.1 million as of December 31, 2021, Depreciation Depletion and Amortization expense was $28.1 million and impairment expense was $0 for the year then ended.

Given the significant judgments made by management and management's specialist, performing audit procedures to evaluate the Company's oil and natural gas reserve quantities, including management's estimates and assumptions related to oil, gas, and NGL prices require a high degree of auditor judgment and an increased extent of effort.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to management's significant judgments and assumptions related to oil and natural gas reserves included the following, among others:

- We tested the design and implementation and operating effectiveness of controls related to the Company's estimation of oil and natural gas properties reserve quantities, including controls relating to the oil, gas, NGL prices.

We evaluated the reasonableness of oil, gas, and NGL prices by comparing such amounts to:

- Third party industry sources
- Historical realized oil, gas, and NGL prices
- Historical realized oil, gas, and NGL price differentials

With the assistance of our fair value specialists, we evaluated management's estimated future oil, gas, and NGL prices and escalation rates by performing the following:

- Understanding the methodology used by management for development of these assumptions and comparing the estimates to independently determined values
- Comparing management's estimates to third-party industry publications and other third-party sources
- We evaluated the Company's estimates around production volumes by evaluating wells' past production performance to ensure it was appropriately reflected in production forecasts used in generating proved reserves
- We evaluated the experience, qualifications and objectivity of management's specialist, an independent reservoir engineering firm, including the methodologies and calculation procedures used to estimate oil and natural gas reserves and performing analytical procedures on the reserve quantities

Southern California Pipeline Incident – Refer to Notes 2, 13 and 15 to the financial statements

Critical Audit Matter Description

The Company has estimated the total aggregate cost with respect to the oil spill off the coast of Newport Beach, California which occurred on October 2, 2021, for (i) actual and projected response and remediation expenses incurred under the direction of the Unified Command. The aggregate costs as estimated are accrued in the consolidated financial statements. The Company also recognizes an insurance receivable when collection of the receivable is deemed probable. The Company has recognized a total liability of $98.8 million as of December 31, 2021. Accrued liabilities – pipeline incident was $34.4 million as of December 31, 2021. Insurance receivables – pipeline incident was $55.8 million. Through December 31, 2021, the Company had collected $48.3 million, net of deductible.

Given the significant judgements made by management, performing audit procedures to evaluate the Company's accrued liabilities – pipeline incident and insurance receivable – pipeline incident, require an increased extent of effort and a need to involve our environmental specialists.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to management's significant judgements and assumptions related to the recognition of costs for the spill and associated insurance receivables included the following, among others:

- We tested the design and implementation and operating effectiveness of controls relating to the Company's recognition of accrued liabilities and insurance receivables.

- We evaluated the estimated total aggregated costs by performing the following:

  - Direct confirmation from service providers and vendors or inspection of official correspondence from certain governmental agencies

  - Sampling on disbursements made after December 31, 2021 to determine if amounts were appropriately accrued for at yearend

  - Direct confirmation with legal advisors

  - Performed a search for claims, litigation, and violations or noncompliance with regulations that have not been considered in the Company's accounting estimate

- We evaluated the insurance receivable by performing the following:

  - Obtained support for reimbursements up to the issuance of the financial statements

    - Vouched the receipt of reimbursements

    - Compared amounts received to amounts reimbursed from insurance providers

  - With the assistance of Environmental Attest Support Specialist, we evaluated the Company's insurance policies for the levels of coverage and loss coverage incidents which could indicate costs that would be non-eligible for reimbursement by the insurance providers

  - With the assistance of Environmental Attest Support Specialist, we evaluated the Company's insurance policies for critical and relevant terms

  - Obtained credit ratings for insurance underwriters

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 9, 2022

We have served as the Company's auditor since 2020.

AMPLIFY ENERGY CORP.
CONSOLIDATED BALANCE SHEETS
(In thousands, except outstanding shares)

	December 31, 2021	December 31, 2020
ASSETS		
Current assets:		
Cash and cash equivalents	$ 18,799	$ 10,364
Accounts receivable, net (see Note 13)	91,967	30,901
Prepaid expenses and other current assets	15,018	15,572
Total current assets	125,784	56,837
Property and equipment, at cost:		
Oil and natural gas properties, successful efforts method	799,532	775,167
Support equipment and facilities	145,324	142,208
Other	9,641	9,102
Accumulated depreciation, depletion and amortization	(634,212)	(609,231)
Property and equipment, net	320,285	317,246
Long-term derivative instruments	—	873
Restricted investments	4,622	4,623
Operating lease - long term right-of-use asset	2,716	2,500
Other long-term assets	1,693	2,680
Total assets	$ 455,100	$ 384,759
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 33,819	$ 798
Revenues payable	20,374	22,563
Accrued liabilities (see Note 13)	57,826	22,677
Short-term derivative instruments	53,144	10,824
Total current liabilities	165,163	56,862
Long-term debt (see Note 8)	230,000	260,516
Asset retirement obligations	102,398	96,725
Long-term derivative instruments	9,664	847
Operating lease liability	2,017	266
Other long-term liabilities	10,699	3,280
Total liabilities	519,941	418,496
Commitments and contingencies (see Note 16)		
Stockholders' equity (deficit):		
Preferred stock, $0.01 par value: 50,000,000 shares authorized; no shares issued and outstanding at December 31, 2021 and December 31, 2020	—	—
Warrants, 2,173,913 warrants issued and outstanding at December 31, 2021 and December 31, 2020	4,788	4,788
Common stock, $0.01 par value: 250,000,000 shares authorized; 38,024,142 and 37,663,509 shares issued and outstanding at December 31, 2021 and December 31, 2020, respectively	382	378
Additional paid-in capital	425,066	424,104
Accumulated deficit	(495,077)	(463,007)
Total stockholders' deficit	(64,841)	(33,737)
Total liabilities and equity	$ 455,100	$ 384,759

See Accompanying Notes to Consolidated Financial Statements.

AMPLIFY ENERGY CORP.
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share amounts)

	For the Year Ended December 31, 2021	For the Year Ended December 31, 2020
Revenues:		
Oil and natural gas sales	$ 335,779	$ 200,888
Other revenues	7,137	1,256
Total revenues	342,916	202,144
Costs and expenses:		
Lease operating expense	121,398	119,708
Gathering, processing and transportation	20,807	20,547
Taxes other than income	22,250	12,944
Depreciation, depletion and amortization	28,068	40,268
Impairment expense	—	476,936
General and administrative expense	25,285	27,789
Accretion of asset retirement obligations	6,611	6,206
Loss (gain) on commodity derivative instruments	142,439	(60,671)
Pipeline incident loss	1,599	—
Other, net	68	306
Total costs and expenses	368,525	644,033
Operating loss	(25,609)	(441,889)
Other (expense) income:		
Interest expense, net	(12,099)	(20,522)
Gain on extinguishment of debt	5,516	—
Inventory valuation adjustment	—	(1,003)
Other expense	128	65
Total other expense	(6,455)	(21,460)
Loss before reorganization items, net and income taxes	(32,064)	(463,349)
Reorganization items, net	(6)	(566)
Income tax expense	—	(115)
Net loss	(32,070)	(464,030)
Net (income) loss allocated to participating restricted stockholders	—	—
Net loss available to common stockholders	$ (32,070)	$ (464,030)
Loss per share: (See Note 10)		
Basic and diluted loss per share	$ (0.84)	$ (12.34)
Weighted average common shares outstanding:		
Basic and diluted	37,959	37,612

See Accompanying Notes to Consolidated Financial Statements.

AMPLIFY ENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	For the Year Ended December 31, 2021	For the Year Ended December 31, 2020
Cash flows from operating activities:		
Net loss	$ (32,070)	$ (464,030)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	28,068	40,268
Impairment expense	—	476,936
Loss (gain) on derivative instruments	142,223	(56,628)
Cash settlements (paid) received on expired derivative instruments	(90,214)	61,135
Cash settlements received on terminated derivative instruments	—	17,977
Bad debt expense	95	294
Amortization and write-off of deferred financing costs	626	3,272
Gain on extinguishment of debt	(5,516)	—
Accretion of asset retirement obligations	6,611	6,206
Share-based compensation (see Note 11)	1,047	(112)
Settlement of asset retirement obligations	(296)	(327)
Changes in operating assets and liabilities:		
Accounts receivable	(61,172)	1,950
Prepaid expenses and other assets	296	(2,334)
Payables and accrued liabilities	73,655	(9,803)
Other	(384)	(474)
Net cash provided by operating activities	62,969	74,330
Cash flows from investing activities:		
Additions to oil and gas properties	(29,294)	(34,833)
Additions to other property and equipment	(539)	(1,057)
Additions to restricted investments	1	—
Other	404	—
Net cash used in investing activities	(29,428)	(35,890)
Cash flows from financing activities:		
Advances on revolving credit facility	—	25,000
Payments on revolving credit facility	(25,000)	(55,000)
Proceeds from the paycheck protection program	—	5,516
Deferred financing costs	(25)	(115)
Dividends to stockholders	—	(3,786)
Shares withheld for taxes	(81)	(51)
Other	—	35
Net cash used in financing activities	(25,106)	(28,401)
Net change in cash and cash equivalents	8,435	10,039
Cash and cash equivalents, beginning of period	10,364	325
Cash and cash equivalents, end of period	$ 18,799	$ 10,364

See Accompanying Notes to Consolidated Financial Statements.

AMPLIFY ENERGY CORP.
CONSOLIDATED STATEMENTS OF EQUITY
(In thousands)

	Stockholders' Equity				
	Common Stock	Warrants	Additional Paid-in Capital	Accumulated Earnings (Deficit)	Total
Balance at December 31, 2019	209	4,790	424,399	4,809	434,207
Net loss	—	—	—	(464,030)	(464,030)
Share-based compensation expense	—	—	(112)	—	(112)
Dividends	—	—	—	(3,786)	(3,786)
Expiration of warrants	—	(2)	2	—	—
Shares withheld for taxes	—	—	(51)	—	(51)
Other	169	—	(134)	—	35
Balance at December 31, 2020	378	4,788	424,104	(463,007)	(33,737)
Net loss	—	—	—	(32,070)	(32,070)
Share-based compensation expense	—	—	1,047	—	1,047
Shares withheld for taxes	—	—	(81)	—	(81)
Other	4	—	(4)	—	—
Balance at December 31, 2021	$ 382	$ 4,788	$ 425,066	$ (495,077)	$ (64,841)

See Accompanying Notes to Consolidated Financial Statements.

AMPLIFY ENERGY CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Organization and Basis of Presentation

General

Amplify Energy Corp. (“Amplify Energy” or the “Company”), is a publicly traded Delaware corporation, in which our common stock is listed on the NYSE under the symbol “AMPY.”

The Company operates in one reportable segment engaged in the acquisition, development, exploitation and production of oil and natural gas properties. The Company’s management evaluates performance based on one reportable business segment as there are not different economic environments within the operation of our oil and natural gas properties. The Company assets consist primarily of producing oil and natural gas properties located in Oklahoma, the Rockies, federal waters offshore Southern California, East Texas/North Louisiana and the Eagle Ford. Most of the Company’s oil and natural gas properties are located in large, mature oil and natural gas reservoirs. The Company’s properties consist primarily of operated and non-operated working interests in producing and undeveloped leasehold acreage and working interests in identified producing wells.

Basis of Presentation

Material intercompany transactions and balances have been eliminated in preparation of the Company’s Consolidated Financial Statements. The accompanying Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America (“GAAP”).

Market Conditions and COVID-19

In March 2020, the World Health Organization classified the outbreak of COVID 19 as a global pandemic. In attempting to control the spread of COVID 19, governments around the world imposed laws and regulations such as shelter-in-place orders, quarantines, executive orders and similar restrictions. As a result, the global economy suffered a significant slowdown and uncertainty, which in turn led to a precipitous decline in commodity prices in response to decreased demand. Beginning in the first quarter of 2021 and continuing throughout the year, commodity prices have recovered substantially, due in part to the accessibility of vaccines, reopening of economies after lockdowns, and general optimism concerning the spread and severity of new variants of COVID-19 and the economic recovery. Despite recent downward trends in the spread of COVID-19, particularly as vaccination rates have increased, new variants of COVID-19 have intermittently emerged and spread throughout the U.S. and globally causing further uncertainty. This continued uncertainty and/or the emergence of new COVID 19 variant, including vaccine resistant variant, may result in additional adverse impacts on our results of operations, cash flows and financial position.

Paycheck Protection Program. On June 22, 2021, KeyBank National Association (“KeyBank”) notified the Company that the loan under the Paycheck Protection Program (the “PPP Loan”) had been approved for full and complete forgiveness by the Small Business Association. For the year ended December 31, 2021, the Company reported a gain on extinguishment of debt for $5.5 million for the PPP Loan forgiveness in the Consolidated Statements of Operations. See Note 8 for additional information.

Employee Retention Credit. The Consolidated Appropriations Act extended and expanded the availability of the Coronavirus Aid, Relief, and Economic Security Act (the “CARES Act”) employee retention credit through September 30, 2021. Subsequently, the American Rescue Plan Act of 2021 (the “ARP Act”), enacted on March 11, 2021, extended and expanded the availability of the employee retention credit through December 31, 2021, however, certain provisions applied only after December 31, 2020. This new legislation expanded the group of qualifying businesses to include businesses with fewer than 500 employees and those who previously qualified for the PPP Loan. The employee retention credit is calculated to be equal to 70% of qualified wages paid to employees after December 31, 2020, and before January 1, 2022. During calendar year 2021, a maximum of $10,000 in qualified wages for each employee per qualifying calendar quarter may be counted in determining the 70% credit. Therefore, the maximum tax credit that can be claimed by an eligible employer is $7,000 per employee per qualifying calendar quarter of 2021. The Company has determined that the qualifications for the credit were met in the first and second quarters of 2021. The Company recognized a $2.8 million employee retention credit for the year ended December 31, 2021, which included an approximate $0.8 million credit to general and administrative expense and an approximate $2.0 million credit to lease operating expense in the Consolidated Statements of Operations.

AMPLIFY ENERGY CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 2. Summary of Significant Accounting Policies

Use of Estimates

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

Significant estimates include, but are not limited to, oil and natural gas reserves; depreciation, depletion and amortization of proved oil and natural gas properties; future cash flows from oil and natural gas properties; impairment of long-lived assets; fair value of derivatives; fair value of equity compensation; fair values of assets acquired and liabilities assumed in business combinations and asset retirement obligations.

Cash and Cash Equivalents

Cash and cash equivalents represent unrestricted cash on hand and all highly liquid investments with original contractual maturities of three months or less.

Concentrations of Credit Risk

Cash balances, accounts receivable, restricted investments and derivative financial instruments are financial instruments potentially subject to credit risk. Cash and cash equivalents are maintained in bank deposit accounts which, at times, may exceed the federally insured limits. Management periodically reviews and assesses the financial condition of the banks to mitigate the risk of loss. Various restricted investment accounts fund certain long-term contractual and regulatory asset retirement obligations and collateralize certain regulatory bonds associated with the offshore Southern California oil and gas properties. These restricted investments consist of money market deposit accounts which are held with credit-worthy financial institutions. Derivative financial instruments are generally executed with major financial institutions that expose us to market and credit risks and which may, at times, be concentrated with certain counterparties. The credit worthiness of the counterparties is subject to continual review. We rely upon netting arrangements with counterparties to reduce credit exposure.

Oil and natural gas are sold to a variety of purchasers, including intrastate and interstate pipelines or their marketing affiliates and independent marketing companies. Accounts receivable from joint operations are from a number of oil and natural gas companies, individuals and others who own interests in the properties operated by the Company. Generally, operators of crude oil and natural gas properties have the right to offset future revenues against unpaid charges related to operated wells, minimizing the credit risk associated with these receivables. An allowance for doubtful accounts is recorded after all reasonable efforts have been exhausted to collect or settle the amount owed. Any amounts outstanding longer than the contractual terms are considered past due. The Company recorded $1.6 million and $1.5 million as an allowance for doubtful accounts at December 31, 2021 and 2020, respectively.

If the Company was to lose any one of its customers, the loss could temporarily delay the production and the sale of oil and natural gas in the related producing region. If it were to lose any single customer, the Company believes that a substitute customer to purchase the impacted production volumes could be identified.

The following individual customers each accounted for 10% or more of total reported revenues for the period indicated:

	For the Year Ended December 31,	
	2021	2020
Major customers:		
Sinclair Oil & Gas Company	20 %	21 %
Phillips 66	19 %	23 %
ETC Texas Pipeline LTD	12 %	n/a %
BP America Production Company	n/a %	17 %

AMPLIFY ENERGY CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Oil and Natural Gas Properties

Oil and natural gas exploration, development and production activities are accounted for in accordance with the successful efforts method of accounting. Under this method, costs of acquiring properties, costs of drilling successful exploration wells and development costs are capitalized. The costs of exploratory wells are initially capitalized, pending a determination of whether proved reserves have been found. At the completion of drilling activities, the costs of exploratory wells remain capitalized if a determination is made that proved reserves have been found. If no proved reserves have been found, the costs of each of the related exploratory wells are charged to expense. In some cases, a determination of proved reserves cannot be made at the completion of drilling, requiring additional testing and evaluation of the wells. The costs of such exploratory wells are expensed if a determination of proved reserves has not been made within a twelve-month period after drilling is complete. Exploration costs such as geological, geophysical, seismic costs and delay rental payments attributable to unproved locations are expensed as incurred.

As exploration and development work progresses and the reserves on these properties are proven, capitalized costs attributed to the properties are subject to depreciation and depletion. Depletion of capitalized costs is provided using the units-of-production method based on proved oil and gas reserves related to the associated field. Capitalized drilling and development costs of producing oil and natural gas properties are depleted over proved developed reserves and leasehold costs are depleted over total proved reserves.

Support equipment and facilities, which are primarily related to our Wyoming and California assets, are depreciated using the straight-line method generally based on estimated useful lives of twelve to twenty-four years.

On the sale or retirement of a complete or partial unit of a proved property or pipeline and related facilities, the cost and related accumulated depreciation, depletion, and amortization are removed from the property accounts, and any gain or loss is recognized.

There were no material capitalized exploratory drilling costs pending evaluation at December 31, 2021 and 2020.

Oil and Natural Gas Reserves

The estimates of proved oil and natural gas reserves utilized in the preparation of the Consolidated Financial Statements are estimated in accordance with the rules established by the SEC and the Financial Accounting Standards Board (“FASB”). These rules require that reserve estimates be prepared under existing economic and operating conditions using a trailing 12-month average price with no provision for price and cost escalations in future years except by contractual arrangements. The development of the Company’s oil and natural gas reserve quantities requires management to make significant estimates and assumptions related to the intent and ability to complete undeveloped proved reserves within a five-year development period, as prescribed by SEC guidelines. Additionally, none of the Company’s PUDs are scheduled to be developed on a date more than five years from the date the reserves were initially booked as PUD as prescribed by the SEC guidelines. PUDs are converted from undeveloped to developed as applicable wells begin production. We engaged Cawley, Gillespie and Associates, Inc. (“CG&A”), our independent reserve engineers, to prepare our reserves estimates for all of the Company’s estimated proved reserves at December 31, 2021 and 2020.

Reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. It is possible that, because of changes in market conditions or the inherent imprecision of reserve estimates, the estimates of future cash inflows, future gross revenues, the amount of oil and natural gas reserves, the remaining estimated lives of oil and natural gas properties, or any combination of the above may be increased or decreased. Increases in recoverable economic volumes generally reduce per unit depletion rates, while decreases in recoverable economic volumes generally increase per unit depletion rates.

Other Property & Equipment

Other property and equipment is stated at historical cost and is comprised primarily of vehicles, furniture, fixtures, office build-out cost and computer hardware and software. Depreciation of other property and equipment is calculated using the straight-line method generally based on estimated useful lives of three to seven years.

AMPLIFY ENERGY CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Restricted Investments

Restricted investment accounts fund certain long-term asset retirement obligations and collateralize certain regulatory bonds associated with the offshore Southern California oil and gas properties. These investments are classified as held-to-maturity and such investments are stated at amortized cost. Interest earned on these investments is included in interest expense, net in the statement of operations. These restricted investments may consist of money market deposit accounts and U.S. Government securities. See Note 7 and Note 16 for additional information.

Debt Issuance Costs

Debt issuance costs are recorded in prepaid expenses and other current assets line item on the balance sheet and amortized over the term of the associated debt using the straight-line method, which generally approximates the effective yield method. Amortization expense, including write-off of debt issuance costs, for the years ended December 31, 2021 and 2020 was approximately $0.6 million and $3.3 million, respectively.

Impairments

Proved oil and natural gas properties are reviewed for impairment when events and circumstances indicate the carrying value of such properties may not be recoverable. This may be due to a downward revision of the reserve estimates, less than expected production, drilling results, higher operating and development costs, or lower commodity prices. The estimated undiscounted future cash flows expected in connection with the property are compared to the carrying value of the property to determine if the carrying amount is recoverable. If the carrying value of the property exceeds its estimated undiscounted future cash flows, the carrying amount of the property is reduced to its estimated fair value using Level 3 inputs. The factors used to determine fair value include, but are not limited to, estimates of proved and probable reserves, future commodity prices, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties. No impairment expense related to its proved properties was recorded for the year ended December 31, 2021. The Company recorded $427.6 million of impairment expense related to its proved properties for the year ended December 31, 2020.

Unproved oil and natural gas properties are reviewed for impairment based on time or geologic factors. Information such as drilling results, reservoir performance, seismic interpretation or future plans to develop acreage is also considered. When unproved property investments are deemed to be impaired, the expense is reported in impairment expense.

No impairment expense related to the Company’s unproved properties was recorded for the year ended December 31, 2021. The Company recognized $49.3 million in impairment expense related to its unproved properties for the year ended December 31, 2020. For the year ended December 31, 2020 the impairment was related to expiring leases and the evaluation of qualitative and quantitative factors related to the current decline in commodity prices.

Significant declines in commodity prices, further changes to the Company’s drilling or development plans, reduction of proved and probable reserve estimates, or increases in drilling or operating costs could result in other additional future impairments to proved and unproved oil and gas properties.

Asset Retirement Obligations

An asset retirement obligation associated with retiring long-lived assets is recognized as a liability on a discounted basis in the period in which the legal obligation is incurred and becomes determinable, with an equal amount capitalized as an addition to oil and natural gas properties, which is allocated to expense over the useful life of the asset. Generally, oil and gas producing companies incur such a liability upon acquiring or drilling a well. Accretion expense is recognized over time as the discounted liabilities are accreted to their expected settlement value. Upon settlement of the liability, a gain or loss is recognized in net income (loss) to the extent the actual costs differ from the recorded liability. See Note 6 for further discussion of asset retirement obligations.

AMPLIFY ENERGY CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Revenue Recognition

The Company revenue is primarily derived from the sale of oil and natural gas production, as well as the sale of NGLs that are extracted from natural gas during processing. Revenue is recognized when the following five steps are completed: (1) identify the contract with the customer, (2) identify the performance obligation (promise) in the contract, (3) determine the transaction price, (4) allocate the transaction price to the performance obligations in the contract, (5) recognize revenue when the reporting organization satisfies a performance obligation.

Revenue from the sale of oil and natural gas is recognized when title passes, net of royalties due to third parties. The performance obligation is the delivery of the commodity at a point in time. Prices for oil, natural gas and NGLs sales are negotiated based on index or spot price, distance from the well to pipeline, commodity quality and prevailing supply and demand conditions. To the extent actual quantities and values of oil, NGLs 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 price for those properties must be estimated.

Derivative Instruments

Commodity derivative financial instruments (e.g., swaps, collars and puts) are used to reduce the impact of natural gas and oil price fluctuations. Every derivative instrument is recorded on the balance sheet as either an asset or liability measured at its fair value. Changes in the derivative's fair value are recognized in earnings as we have not elected hedge accounting for any of our derivative positions.

Income Tax

The Company is a corporation subject to federal and certain state income taxes.

The Company uses the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the tax basis of assets and liabilities and their reported amounts in the financial statements and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. Deferred tax assets are reduced by a valuation allowance if, based on the weight of available evidence, it is more likely than not that some portion or all of deferred tax assets will not be realized.

The Company recognizes a tax benefit from an uncertain tax position when it is more likely than not that the position will be sustained upon examination by taxing authorities, based on the technical merits of the position. The tax benefit recorded is equal to the largest amount that is greater than 50% likely to be realized through effective settlement with a taxing authority. We recognize interest and penalties accrued to unrecognized tax benefits in other income (expense) in our Consolidated Statement of Operations. Although we believe our assumptions, judgments and estimates are reasonable, changes in tax laws or our interpretation of tax laws and the resolution of any tax audits could significantly impact the amounts provided for income taxes in our consolidated financial statements.

Earnings (loss) Per Share

Basic and diluted earnings (loss) per share ("EPS") is determined by dividing net income (loss) available to the common stockholders by the weighted average number of outstanding shares during the period. Diluted earnings (loss) per common share is calculated under the two-class method and the treasury stock method by dividing net income (loss) available to common stockholders by the weighted average number of diluted common shares outstanding, which includes the effect of potentially dilutive securities. When a loss from continuing operations exists, all potentially dilutive securities are anti-dilutive and are therefore excluded from the computation of diluted earnings per share. See Note 10 for additional information.

AMPLIFY ENERGY CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Equity Compensation

The fair value of equity-classified awards (e.g., restricted common unit awards, restricted stock units or stock options) is amortized to earnings over the requisite service or vesting period. Compensation expense for liability-classified awards (e.g., phantom units awards) are recognized over the requisite service or vesting period of an award based on the fair value of the award re-measured at each reporting period. The Company currently has awards subject to performance criteria; such awards would vest when it is probable that the performance criteria will be met and the requisite service period has been met. Generally, no compensation expense is recognized for equity instruments that do not vest. See Note 11 for further information.

Lease Recognition

The FASB retained a dual model, requiring leases to be classified as either direct financing or operating leases. The classification will be based on criteria that are similar to the current lease accounting treatment. The Company is the lessee under various agreements for office space, warehouse, compressors, equipment, vehicles and surface rentals (right of use assets) that are currently accounted for as operating leases. See Note 12 for additional information regarding leases.

Loss of Production Income Insurance

The Company's insurance coverage includes loss of production income ("LOPI") insurance for our offshore properties. Proceeds from LOPI insurance claims are intended to partially offset the loss of revenue resulting from certain events that cause suspension of operations. When such event occurs, the Company files claims under its LOPI policy and recognizes LOPI in the period that insurers accept the claim, and no uncertainty exists with respect to the receipt or amount of claim proceeds. The Company classifies LOPI within "Other revenues" in the Consolidated Statement of Operations.

For the period from October 2, 2021 through December 31, 2021, the Company recognized LOPI insurance payments of $6.7 million from our Beta properties due to the pipeline incident that occurred on October 2, 2021. The Company's LOPI insurance policy in effect at the time of the pipeline incident provides eighteen months of LOPI coverage. See Note 15 for additional information regarding the pipeline incident.

Insurance Coverage

The Company recognizes an insurance receivable when collection of the receivable is deemed probable. Any recognition of an insurance receivable is recorded by crediting and offsetting the original charge. Any differential arising between the insurance recoveries and insurance receivables is recorded as a capitalized cost or as an expense, consistent with its original treatment. See Note 15 for additional information regarding the pipeline incident.

New Accounting Pronouncements

Income Taxes – Simplifying the Accounting for Income Taxes. In December 2019, the FASB issued an accounting standards update which simplifies the accounting for income taxes by removing certain exceptions to the general principles in Topic 740. This accounting standards update removes the following exceptions: (i) exception to the incremental approach for intraperiod tax allocation when there is a loss continuing operations and income or a gain from other items; (ii) exception to the requirements to recognize a deferred tax liability for equity method investments when a foreign subsidiary becomes an equity method investment; (iii) exception to the ability not to recognize a deferred tax liability for a foreign subsidiary when a foreign equity method investment becomes a subsidiary; and (iv) exception to the general methodology for calculating income taxes in an interim period when a year-to-date loss exceeds the anticipated loss for the year. The amendments in the accounting standards update also improve consistency and simplify other areas of Topic 740 by clarifying and amending existing guidance. The new guidance is effective for fiscal years and interim periods within those fiscal years, beginning after December 15, 2020. The Company adopted the guidance effective January 1, 2021, with all of the anticipated and applicable effects to be required on a prospective basis. The adoption of this guidance did not have a material impact on our consolidated financial statements.

No other accounting standards issued by the FASB or other standards-setting bodies are expected to have a material impact on the Company's financial position, results of operations and cash flows.

AMPLIFY ENERGY CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 3. Revenues

Revenue from contracts with customers

Revenue is recognized when the following five steps are completed: (1) identify the contract with the customer, (2) identify the performance obligation (promise) in the contract, (3) determine the transaction price, (4) allocate the transaction price to the performance obligations in the contract, (5) recognize revenue when the reporting organization satisfies a performance obligation.

The Company has determined that its contracts for the sale of crude oil, unprocessed natural gas, residue gas and NGLs contain monthly performance obligations to deliver product at locations specified in the contract. Control is transferred at the delivery location, at which point the performance obligation has been satisfied and revenue is recognized. Fees included in the contract that are incurred prior to control transfer are classified as gathering, processing and transportation and fees incurred after control transfers are included as a reduction to the transaction price. The transaction price at which revenue is recognized consists entirely of variable consideration based on quoted market prices less various fees and the quantity of volumes delivered.

Disaggregation of Revenue

The Company has identified three material revenue streams in its business: oil, natural gas and NGLs. The following table presents the Company's revenues disaggregated by revenue stream.

	For the Year Ended December 31,	
	2021	2020
	(in thousands)	
Revenues		
Oil	$ 212,486	$ 138,273
NGLs	$ 40,899	$ 20,064
Natural gas	$ 82,394	$ 42,551
Oil and natural gas sales	$ 335,779	$ 200,888

Contract Balances

Under its sales contracts, the Company invoices customers once its performance obligations have been satisfied, at which point payment is unconditional. Accordingly, its contracts do not give rise to contract assets or liabilities. Accounts receivable attributable to the Company's revenue contracts with customers were $32.4 million and $25.6 million at December 31, 2021 and 2020, respectively.

Transaction Price Allocated to Remaining Performance Obligations

For the Company's contracts that have a contract term greater than one year, the Company has utilized the practical expedient in ASC 606, which states that a company is 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 the Company's contracts, each unit of product delivered to the customer 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. For the Company's contracts that have a contract term of one year or less, the Company has utilized the practical expedient in ASC 606, which states that a company is not required to disclose 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.

AMPLIFY ENERGY CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 4. Fair Value Measurements of Financial Instruments

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at a specified measurement date. Fair value estimates are based on either (i) actual market data or (ii) assumptions that other market participants would use in pricing an asset or liability, including estimates of risk. A three-tier hierarchy has been established that classifies fair value amounts recognized or disclosed in the financial statements. The hierarchy considers fair value amounts based on observable inputs (Levels 1 and 2) to be more reliable and predictable than those based primarily on unobservable inputs (Level 3). The characteristics of fair value amounts classified within each level of the hierarchy are described as follows:

Level 1 — Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. An active market is one in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 — Quoted prices in markets that are not active, or inputs that are observable, either directly or indirectly, for substantially the full term of the asset or liability. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data, or are supported by observable levels at which transactions are executed in the marketplace. At December 31, 2021 and 2020, all of the derivative instruments reflected on the accompanying balance sheets were considered Level 2.

Level 3 — Measure based on prices or valuation models that require inputs that are both significant to the fair value measurement and are less observable from objective sources (i.e., supported by little or no market activity).

Assets and Liabilities Measured at Fair Value on a Recurring Basis

The carrying values of cash and cash equivalents (Level 1), accounts receivables, accounts payables (including accrued liabilities) and amounts outstanding under long-term debt agreements with variable rates included in the accompanying balance sheets approximated fair value at December 31, 2021 and 2020. The fair value estimates are based upon observable market data and are classified within Level 2 of the fair value hierarchy. These assets and liabilities are not presented in the following tables. See Note 8 for the estimated fair value of our outstanding fixed-rate debt.

The fair market values of the derivative financial instruments reflected on the balance sheets as of December 31, 2021 and 2020 were based on estimated forward commodity prices (including nonperformance risk). Nonperformance risk is the risk that the obligation related to the derivative instrument will not be fulfilled. Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement in its entirety. The significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

AMPLIFY ENERGY CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table presents the derivative assets and liabilities that are measured at fair value on a recurring basis at December 31, 2021 and December 31, 2020 for each of the fair value hierarchy levels:

	Fair Value Measurements at December 31, 2021 Using			
	Quoted Prices in Active Market (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Fair Value
	(In thousands)			
Assets:				
Commodity derivatives	$ —	$ 7,967	$ —	$ 7,967
Interest rate derivatives	—	—	—	—
Total assets	$ —	$ 7,967	$ —	$ 7,967
Liabilities:				
Commodity derivatives	$ —	$ 70,152	$ —	$ 70,152
Interest rate derivatives	—	623	—	623
Total liabilities	$ —	$ 70,775	$ —	$ 70,775

	Fair Value Measurements at December 31, 2020 Using			
	Quoted Prices in Active Market (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Fair Value
	(In thousands)			
Assets:				
Commodity derivatives	$ —	$ 15,449	$ —	$ 15,449
Interest rate derivatives	—	—	—	—
Total assets	$ —	$ 15,449	$ —	$ 15,449
Liabilities:				
Commodity derivatives	$ —	$ 23,495	$ —	$ 23,495
Interest rate derivatives	—	2,752	—	2,752
Total liabilities	$ —	$ 26,247	$ —	$ 26,247

See Note 5 for additional information regarding our derivative instruments.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are reported at fair value on a nonrecurring basis, as reflected on the balance sheets. The following methods and assumptions are used to estimate the fair values:

- The fair value of asset retirement obligations ("AROs") is based on discounted cash flow projections using numerous estimates, assumptions, and judgments regarding such factors as the existence of a legal obligation for an ARO; amounts and timing of settlements; the credit-adjusted risk-free rate; and inflation rates. The initial fair value estimates are based on unobservable market data and are classified within Level 3 of the fair value hierarchy. See Note 6 for a summary of changes in AROs.

- If sufficient market data is not available, the determination of the fair values of proved and unproved properties acquired in transactions accounted for as business combinations are prepared by utilizing estimates of discounted cash flow projections. The factors to determine fair value include, but are not limited to, estimates of: (i) economic reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital. The fair value of supporting equipment, such as plant assets, acquired in transactions accounted for as business combinations is commonly estimated using the depreciated replacement cost approach.

- Proved oil and natural gas properties are reviewed for impairment when events and circumstances indicate the carrying value of such properties may not be recoverable. The Company uses an income approach based on the discounted cash flow method, whereby the present value of expected future net cash flows are discounted by applying an appropriate discount rate, for purposes of placing a fair value on the assets. The future cash flows are based on management's estimates for the future. The unobservable inputs used to determine fair value include, but are not limited to, estimates of proved reserves, estimates of probable reserves, future commodity prices, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties (some of which are Level 3 inputs within the fair value hierarchy).

    (i) No impairment expense on our proved oil and natural gas properties recorded for the year ended December 31, 2021.

    (ii) The Company recognized $427.6 million of impairment expense on our proved oil and natural gas properties for the year ended December 31, 2020. These impairments related to certain properties located in East Texas, the Rockies, offshore Southern California and the Eagle Ford. The estimated future cash flows expected from these properties were compared to their carrying values and determined to be unrecoverable primarily as a result of declining commodity prices. The impairments were due to a decline in the value of estimated proved reserves based on declining commodity prices.

- Unproved oil and natural gas properties are reviewed for impairment based on time or geologic factors. Information such as drilling results, reservoir performance, seismic interpretation or future plans to develop acreage is also considered.

    (iii) No impairment expense on our unproved oil and natural gas properties recorded for the year ended December 31, 2021.

    (i) The Company recognized $49.3 million of impairment expense on unproved properties for the year ended December 31, 2020, which was related to expiring leases and the evaluation of qualitative and quantitative factors related to the current decline in commodity prices.

Note 5. Risk Management and Derivative Instruments

Derivative instruments are utilized to manage exposure to commodity price fluctuations and achieve a more predictable cash flow in connection with natural gas and oil sales from production. These transactions limit exposure to declines in prices but also limit the benefits that would be realized if prices increase.

Certain inherent business risks are associated with commodity and interest derivative contracts, including market risk and credit risk. Market risk is the risk that the price of natural gas or oil will change, either favorably or unfavorably, in response to changing market conditions. Credit risk is the risk of loss from nonperformance by the counterparty to a contract. It is our policy to enter into derivative contracts, only with creditworthy counterparties, which generally are financial institutions, deemed by management as competent and competitive market makers. Some of the lenders, or certain of their affiliates, under our previous and current credit agreement are counterparties to our derivative contracts. While collateral is generally not required to be posted by counterparties, credit risk associated with derivative instruments is minimized by limiting exposure to any single counterparty and entering into derivative instruments only with creditworthy counterparties that are generally large financial institutions. Additionally, master netting agreements are used to mitigate risk of loss due to default with counterparties on derivative instruments. The Company enters into International Swaps and Derivatives Association Master Agreements ("ISDA Agreements") with each of its counterparties. The terms of the ISDA Agreements provides the Company and each of its counterparties with rights of set-off upon the occurrence of defined acts of default by either the Company or its counterparty to a derivative, whereby the party not in default may set-off all liabilities owed to the defaulting party against all net derivative asset receivables from the defaulting party. At December 31, 2021, after taking into effect netting arrangements, the Company had no counterparty exposure related to its derivative instruments. See Note 8 for additional information regarding the Company's Revolving Credit Facility.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Commodity Derivatives

A combination of commodity derivatives (e.g., floating-for-fixed swaps, put options, costless collars, and three-way collars) is used to manage exposure to commodity price volatility.

In April 2020, the Company monetized a portion of its 2021 crude oil hedges for total cash proceeds of approximately $18.0 million.

The Company enters into natural gas derivative contracts that are indexed to NYMEX Henry Hub. The Company also enters into oil derivative contracts indexed to either NYMEX WTI or Inter-Continental Exchange ("ICE") Brent. Its NGL derivative contracts are indexed to Oil Price Information Service Mont Belvieu.

At December 31, 2021, the Company had the following open commodity positions:

	2022	2023
Natural Gas Derivative Contracts:		
Fixed price swap contracts:		
Average monthly volume (MMBtu)	695,000	—
Weighted-average fixed price	$ 2.56	$ —
Collar contracts:		
Two-way collars		
Average monthly volume (MMBtu)	775,000	370,000
Weighted-average floor price	$ 2.56	$ 2.63
Weighted-average ceiling price	$ 3.44	$ 3.61
Crude Oil Derivative Contracts:		
Fixed price swap contracts:		
Average monthly volume (Bbls)	64,000	55,000
Weighted-average fixed price	$ 49.56	$ 57.30
Collar contracts:		
Two-way collars		
Average monthly volume (Bbls)	22,500	—
Weighted-average floor price	$ 58.33	$ —
Weighted-average ceiling price	$ 67.42	$ —
Three-way collars		
Average monthly volume (Bbls)	89,000	30,000
Weighted-average ceiling price	$ 55.55	$ 67.15
Weighted-average floor price	$ 42.92	$ 55.00
Weighted-average sub-floor price	$ 32.58	$ 40.00

Interest Rate Swaps

Periodically, the Company enters into interest rate swaps to mitigate exposure to market rate fluctuations by converting variable interest rates such as those in its credit agreement to fixed interest rates. At December 31, 2021, the Company had the following interest rate swaps open positions:

	2022
Average Monthly Notional (in thousands)	$ 75,000
Weighted-average fixed rate	1.281 %
Floating rate	1 Month LIBOR

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Balance Sheet Presentation

The following table summarizes both: (i) the gross fair value of derivative instruments by the appropriate balance sheet classification even when the derivative instruments are subject to netting arrangements and qualify for net presentation in the balance sheet and (ii) the net recorded fair value as reflected on the balance sheet at December 31, 2021 and 2020. There was no cash collateral received or pledged associated with its derivative instruments since most of the counterparties, or certain of their affiliates, to its derivative contracts are lenders under the Company's Credit Agreement (as defined below).

Type	Balance Sheet Location	Asset Derivatives December 31, 2021	Liability Derivatives December 31, 2021	Asset Derivatives December 31, 2020	Liability Derivatives December 31, 2020
		(In thousands)			
Commodity contracts	Short-term derivative instruments	$ 4,804	$ 57,325	$ 6,088	$ 15,007
Interest rate swaps	Short-term derivative instruments	—	623	—	1,905
Gross fair value		4,804	57,948	6,088	16,912
Netting arrangements		(4,804)	(4,804)	(6,088)	(6,088)
Net recorded fair value	Short-term derivative instruments	$ —	$ 53,144	$ —	$ 10,824
Commodity contracts	Long-term derivative instruments	$ 3,163	$ 12,827	$ 9,361	$ 8,488
Interest rate swaps	Long-term derivative instruments	—	—	—	847
Gross fair value		3,163	12,827	9,361	9,335
Netting arrangements		(3,163)	(3,163)	(8,488)	(8,488)
Net recorded fair value	Long-term derivative instruments	$ —	$ 9,664	$ 873	$ 847

(Gains) Losses on Derivatives

The Company does not designate derivative instruments as hedging instruments for accounting and financial reporting purposes. Accordingly, all gains and losses, including changes in the derivative instruments' fair values, have been recorded in the accompanying statements of operations. The following table details the gains and losses related to derivative instruments for the periods indicated (in thousands):

	Statements of Operations Location	For the Year Ended December 31, 2021	For the Year Ended December 31, 2020
Commodity derivative contracts	Loss (gain) on commodity derivatives	$ 142,439	$ (60,671)
Loss (gain) on interest rate derivatives	Interest expense, net	(217)	4,044

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Note 6. Asset Retirement Obligations

The Company's asset retirement obligations primarily relate to the Company's portion of future plugging and abandonment of wells and related facilities. The following table presents the changes in the asset retirement obligations for the years ended December 31, 2021 and 2020 (in thousands):

	For the Year Ended December 31, 2021	For the Year Ended December 31, 2020
Asset retirement obligations at beginning of period	$ 97,149	$ 91,089
Liabilities added from acquisition or drilling	29	79
Liabilities settled	(296)	(327)
Liabilities removed upon sale of wells	(113)	—
Accretion expense	6,611	6,206
Revision of estimates	34	102
Asset retirement obligation at end of period	103,414	97,149
Less: Current portion	1,016	424
Asset retirement obligations - long-term portion	$ 102,398	$ 96,725

Note 7. Restricted Investments

Various restricted investment accounts fund certain long-term contractual and asset retirement obligations and collateralize certain regulatory bonds associated with the offshore Southern California oil and gas properties. The components of the restricted investment balances are as follows:

	December 31, 2021	December 31, 2020
	(In thousands)	
BOEM platform abandonment (See Note 16)	$ 313	$ 313
SPBPC Collateral:		
Contractual pipeline and surface facilities abandonment	4,309	4,310
Restricted investments	$ 4,622	$ 4,623

Note 8. Debt

The Company's consolidated debt obligations consisted of the following at the dates indicated:

	December 31, 2021	December 31, 2020
	(In thousands)	
Revolving Credit Facility (1)	$ 230,000	$ 255,000
Paycheck Protection Program loan (2)	—	5,516
Total long-term debt	$ 230,000	$ 260,516

(1) The carrying amount of the Company's Revolving Credit Facility approximates fair value because the interest rates are variable and reflective of market rates.
(2) See below for additional information regarding the receipt and the forgiveness of the paycheck protection program loan.

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Revolving Credit Facility

On November 2, 2018, OLLC and Amplify Acquisitionco, Inc. ("Acquistionco") entered into a credit agreement (the "Credit Agreement"), providing for a reserve-based revolving credit facility (the "Revolving Credit Facility"), subject to a borrowing base of $245.0 million as of December 31, 2021, which is guaranteed by us and all of the Company's current subsidiaries. The Credit Agreement matures on November 2, 2023. The borrowing base under the Company's Credit Agreement is subject to redetermination on at least a semi-annual basis based on an engineering report with respect to its estimated oil, NGL and natural gas reserves, which will take into account the prevailing oil, NGL and natural gas prices at such time, as adjusted for the impact of commodity derivative contracts. Unanimous approval by the lenders is required for any increase to the borrowing base.

The terms and conditions under the original Credit Agreement include (but are not limited to) the following:

- at OLLC's option, borrowings under the Credit Agreement will bear interest at the base rate, LIBOR Market Index rate or LIBOR plus an applicable margin. Base rate loans bear interest at a rate per annum equal to the greatest of: (i) the federal funds effective rate plus 50 basis points, (ii) the rate of interest in effect for each day as publicly announced from time to time by the agent as its "prime rate"; and (iii) the adjusted LIBOR rate for a one-month interest period plus 100 basis points per annum. The applicable margin for base rate loans ranges from 100 to 200 basis points, and the applicable margin for LIBOR loans and LIBOR Market loans ranges from 200 to 300 basis points, in each case depending on the percentage of the borrowing base utilized;

- the obligations under the Revolving Credit Facility are secured by mortgages on not less than 85% of the PV-9 value of oil and gas properties (and at least 85% of the PV-9 value of the proved, developed and producing oil and gas properties) included in the determination of the borrowing base. OLLC and its other subsidiaries entered into a pledge and security agreement in favor of the agent for the secured parties, pursuant to which OLLC's obligations under the Credit Agreement are secured by a first priority security interest in substantially all of our assets (subject to permitted liens). Additionally, the Company entered into a non-recourse pledge agreement in favor of the agent for the secured parties, pursuant to which OLLC's obligations under the Credit Agreement are secured by a pledge and security interest of 100% of the equity interests held by the Company in Acquisitionco;

- 0.5% fee on unused line of credit;

- certain financial covenants, including the maintenance of (i) as of the date of determination, a maximum total debt to EBITDAX ratio of 4.00 to 1.00, and (ii) a current ratio of not less than 1.00 to 1.00; and

- certain events of default, including, without limitation: non-payment; breaches of representations and warranties; non-compliance with covenants or other agreements; cross-default to material indebtedness; judgments; change of control; and voluntary and involuntary bankruptcy.

Borrowing Base Redetermination Agreement and Fifth Amendment

On November 10, 2021, the Company completed its scheduled semi-annual borrowing base redetermination process, pursuant to which the borrowing base under the Revolving Credit Facility was reaffirmed at $245.0 million; provided that, beginning on February 28, 2022, the borrowing base will be reduced by $5.0 million per month on the last calendar day of each month until the next regularly scheduled redetermination, which is expected to occur in April 2022.

Borrowing Base Redetermination

On June 16, 2021, the Company completed its scheduled semi-annual borrowing base redetermination process, pursuant to which the borrowing base under the Revolving Credit Facility was decreased from $260.0 million to $245.0 million. In addition to the redetermination, the administrative agent under the Revolving Credit Facility agreement was changed from Bank of Montreal to KeyBank.

AMPLIFY ENERGY CORP.
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Borrowing Base Redetermination Agreement and Fourth Amendment

On November 17, 2020, the Company entered into the Borrowing Base Redetermination Agreement and Fourth Amendment to Credit Agreement, among the Borrower, Amplify Acquisitionco LLC, a Delaware limited liability company, the guarantors party thereto, the lenders party thereto and Bank of Montreal, as administrative agent (the "Fourth Amendment"). The Fourth Amendment amended the parties' existing Credit Agreement, to among other things:

- reaffirm the borrowing base under the Credit Agreement at $260.0 million; and
- modify the affirmative hedging covenant to include at least 65% and 45% hedge for calendar years 2021 and 2022 on a total proved developed producing reserves, respectively.

The foregoing description of the Fourth Amendment is qualified in its entirety by reference to the Fourth Amendment, which is attached as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on November 18, 2020.

Borrowing Base Redetermination Agreement and Third Amendment

On June 12, 2020, the Company entered into the Borrowing Base Redetermination Agreement and Third Amendment to Credit Agreement, among the Borrower, Amplify Acquisitionco LLC, a Delaware limited liability company, the guarantors party thereto, the lenders party thereto and Bank of Montreal, as administrative agent (the "Third Amendment"). The Third Amendment amended the parties' existing Credit Agreement, to among other things:

- reduce the borrowing base under the Credit Agreement from $450.0 million to $285.0 million, with monthly reductions of $5.0 million thereafter until the borrowing base is reduced to $260.0 million, effective November 1, 2020;
- increase the amount of first priority liens on all assets from at least 85% to 90%;
- the applicable margin for LIBOR loans and LIBOR Market loans increased from 200 to 300 basis points to 250 to 350 basis points.
- suspend certain financial covenants for the quarter ended June 30, 2020;
- amend the definition of "Consolidated EBITDAX" in the Credit Agreement to decrease the limit of cash and cash equivalents permitted from $30.0 million to $25.0 million and increase the limit of transaction-related expense add-backs from $5.0 million to $20.0 million;
- increase the minimum hedging requirements to at least 30% - 60% of our estimated production from total proved developed producing reserves;
- incorporate a mandatory prepayment at times when cash and cash equivalents (as defined in the Credit Agreement) on hand exceed $25.0 million for five consecutive business days; and
- amend certain other covenants and provisions.

The foregoing description of the Third Amendment is qualified in its entirety by reference to the Third Amendment, which is attached as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on June 15, 2020.

Debt Compliance

As of December 31, 2021, we were in compliance with all the financial (current ratio and total leverage ratio) and non-financial covenants associated with the Company's Revolving Credit Facility.

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Paycheck Protection Program

On April 24, 2020, the Company received a $5.5 million loan under the Paycheck Protection Program (the "PPP Loan"). The Paycheck Protection Program was established as part of the CARES Act to provide loans to qualifying businesses. The loans and accrued interest are potentially forgivable, provided that the borrower uses the loan proceeds for eligible purposes. The term of the Company's PPP Loan was two years with an annual interest rate of 1% and no payments of principal or interest due during the six-month period beginning on the date of the PPP Loan. The Company applied for forgiveness of the amount due on the PPP Loan based on spending the loan proceeds on eligible expenses as defined by the statute. On June 22, 2021, KeyBank notified the Company that the PPP Loan had been approved for full and complete forgiveness by the Small Business Association. For the year ended December 31, 2021, the Company reported a gain on extinguishment of debt of $5.5 million for the PPP Loan forgiveness in the Consolidated Statements of Operations.

Weighted-Average Interest Rates

The following table presents the weighted-average interest rates paid on variable-rate debt obligations for the periods presented:

	For the Year Ended December 31,	
	2021	2020
Revolving Credit Facility	3.65 %	3.63 %

Letters of credit

At December 31, 2021, the Company had no letters of credit outstanding.

Unamortized Deferred Financing Costs

Unamortized deferred financing costs associated with the Revolving Credit Facility was $1.0 million at December 31, 2021. The unamortized deferred financing costs are amortized over the remaining life of the Revolving Credit Facility using the straight-line method, which generally approximates the effective interest method.

For the year ended December 31, 2020, the Company wrote-off $2.4 million of deferred financing costs in connection with the decrease in the Company's borrowing base.

AMPLIFY ENERGY CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 9. Equity (Deficit)

Equity Outstanding

The Company's authorized capital stock includes 250,000,000 shares of common stock, $0.01 par value per share. The following table summarizes the changes in the number of outstanding common units and shares of common stock:

	Common Stock
Balance, December 31, 2019	37,566,540
Issuance of common stock	—
Restricted stock units vested	132,237
Shares withheld for taxes (1)	(35,268)
Balance, December 31, 2020	37,663,509
Issuance of common stock	—
Restricted stock units vested	77,985
Bonus stock awards (2)	455,973
Shares withheld for taxes (1)	(173,325)
Balance, December 31, 2021	38,024,142

(1) Represents the net settlement on vesting of restricted stock necessary to satisfy the minimum statutory tax withholding requirements.
(2) Reflects shares granted to certain executive officers and employees pursuant to the Company's annual incentive bonus program. Shares were granted on February 12, 2021 at a grant price of $2.48 per share.

Warrants

Legacy Amplify entered into a warrant agreement (the "Warrant Agreement") with American Stock Transfer & Trust Company, LLC, as warrant agent ("AST"), pursuant to which Legacy Amplify issued warrants to purchase up to 2,173,913 shares of Legacy Amplify's common stock (representing 8% of Legacy Amplify's outstanding common stock on May 4, 2017, including shares of Legacy Amplify's common stock issuable upon full exercise of the warrants, but excluding any common stock issuable under the Legacy Amplify's Management Incentive Plan), exercisable for a five year period commencing on May 4, 2017 at an exercise price of $42.60 per share. The warrants will expire on May 4, 2022.

The fair values for the warrants upon issuance were estimated using the Black-Scholes option pricing model using the following assumptions:

	Warrants Issued in Successor Period
Risk-free interest rate	2.06 %
Dividend yield	—
Expected life (in years)	5.0
Expected volatility	50.0 %
Strike Price	$ 42.60
Calculated fair value	$ 2.20

Cash Dividend Payment

On March 3, 2020, the Company's board of directors approved a dividend of $0.10 per share of outstanding common stock or $3.8 million in aggregate, which was paid on March 30, 2020, to stockholders of record at the close of business on March 16, 2020. The board of directors subsequently suspended quarterly dividends. Future dividends, if any, are subject to debt covenants under the Revolving Credit Facility and discretionary approval by the board of directors.

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Note 10. Earnings per Share

The following sets forth the calculation of earnings (loss) per share, or EPS, for the periods indicated (in thousands, except per share amounts):

	For the Year Ended December 31, 2021	For the Year Ended December 31, 2020
Net loss	$ (32,070)	$ (464,030)
Less: Net income allocated to participating restricted stockholders	—	—
Basic and diluted earnings available to common stockholders	$ (32,070)	$ (464,030)
Common shares:		
Common shares outstanding — basic	37,959	37,612
Dilutive effect of potential common shares	—	—
Common shares outstanding — diluted	37,959	37,612
Net earnings (loss) per share:		
Basic	$ (0.84)	$ (12.34)
Diluted	$ (0.84)	$ (12.34)
Antidilutive warrants (1)	2,174	2,174

(1) Amount represents warrants to purchase common stock that are excluded from the diluted net earnings per share calculations because of their antidilutive effect.

Note 11. Equity-based Awards

In May 2021, the Company shareholders approved a new Equity Incentive Plan ("EIP") in which the Legacy Amplify Management Incentive Plan (the "Legacy Amplify MIP") and the Legacy Amplify 2017 Non-Employee Directors Compensation Plan (the "Legacy Amplify Non-Employee Directors Compensation Plan") were replaced by the EIP and no further awards will be allowed to be granted under the Legacy Amplify MIP or the Legacy Amplify Non-Employee Directors Compensation Plan.

EIP awards and Legacy Amplify MIP awards are granted in the form of nonqualified stock options, incentive stock options, restricted stock awards, restricted stock units, stock appreciation rights, performance awards, stock awards and other incentive awards. To the extent that an award under the EIP or Legacy Amplify MIP is expired, forfeited or canceled for any reason without having been exercised in full, the unexercised award would then be available again for future grants under the EIP. The EIP is administered by the board of directors of the Company. At December 31, 2021, the Company had 2,789,054 shares remaining available for issuance under the EIP.

Restricted Stock Units

Restricted Stock Units with Service Vesting Condition

Restricted stock units with service vesting conditions ("TSUs") are accounted for as equity-classified awards. The grant-date fair value is recognized as compensation cost on a straight-line basis over the requisite service period and forfeitures are accounted for as they occur. Compensation costs are recorded as general and administrative expense. The unrecognized cost associated with TSUs was $2.5 million at December 31, 2021. The Company expects to recognize the unrecognized compensation cost for these awards over a weighted-average period of 2.0 years.

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The following table summarizes information regarding the TSUs granted under the EIP and Legacy Amplify MIP for the period presented:

	Number of Units	Weighted-Average Grant-Date Fair Value per Unit (1)
TSUs outstanding at December 31, 2019	291,370	$ 5.18
Granted (2)	43,250	$ 3.10
Forfeited	(93,845)	$ 5.12
Vested	(124,978)	$ 5.17
TSUs outstanding at December 31, 2020	115,797	$ 4.47
Granted (3)	1,083,644	$ 3.65
Forfeited	(52,601)	$ 3.73
Vested	(72,420)	$ 4.74
TSUs outstanding at December 31, 2021	1,074,420	$ 3.66

(1) Determined by dividing the aggregate grant date fair value of awards by the number of awards issued.
(2) The aggregate grant date fair value of TSUs issued for the year ended December 31, 2020 was $0.1 million based on a grant date market price ranging from $0.54 to $6.61 per share.
(3) The aggregate grant date fair value of TSUs issued for the year ended December 31, 2021 was $4.0 million based on a grant date market price ranging from $3.52 to $4.66 per share.

Restricted Stock Units with Market and Service Vesting Conditions

Restricted stock units with market and service vesting conditions (“PSUs”) are accounted for as equity-classified awards. The grant-date fair value is recognized as compensation cost on a graded-vesting basis. As such, the Company recognizes compensation cost over the requisite service period for each separately vesting tranche of the award as though the award were, in substance, multiple awards. The Company accounts for forfeitures as they occur. Compensation costs are recorded as general and administrative expense. The unrecognized cost related to the PSUs was less than $0.1 million at December 31, 2021. The Company expects to recognize the unrecognized compensation cost for these awards over a weighted-average period of approximately 1.2 years.

The PSUs will vest based on the satisfaction of service and market vesting conditions with market vesting based on the Company’s achievement of certain share price targets. The PSUs are subject to service-based vesting such that 50% of the PSUs service vest on the applicable market vesting date and an additional 25% of the PSUs service vest on each of the first and second anniversaries of the applicable market vesting date.

In the event of a qualifying termination, subject to certain conditions, (i) all PSUs that have satisfied the market vesting conditions will fully service vest, upon such termination, and (ii) if the termination occurs between the second and third anniversaries of the grant date, then PSUs that have not market vested as of the termination will market vest to the extent that the share targets (in each case, reduced by $0.25) are achieved as of such termination. Subject to the foregoing, any unvested PSUs will be forfeited upon termination of employment.

A Monte Carlo simulation was used to determine the fair value of these awards at the grant date.

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The following table summarizes information regarding the PSUs granted under EIP and the Legacy Amplify MIP for the period presented:

	Number of Units	Weighted-Average Grant-Date Fair Value per Unit (1)
PSUs outstanding at December 31, 2019	305,893	$ 2.15
Granted (2)	43,250	$ 3.03
Forfeited	(134,589)	$ 2.11
Vested	—	$ —
PSUs outstanding at December 31, 2020	214,554	$ 2.36
Granted	—	$ —
Forfeited	(148,614)	$ 2.13
Vested	—	$ —
PSUs outstanding at December 31, 2021	65,940	$ 2.87

(1) Determined by dividing the aggregate grant date fair value of awards by the number of awards issued.
(2) The aggregate grant date fair value of PSUs issued for the year ended December 31, 2020 was $0.1 million based on a calculated fair value price ranging from $2.46 to $3.66 per share.

Restricted Stock Units with Market Vesting Conditions

The restricted stock units with performance-based vesting conditions (“PRSUs”) are accounted for as equity-classified awards. The grant-date fair value is recognized as compensation cost on a graded-vesting basis. As such, the Company recognizes compensation cost over the requisite service period for each separately vesting tranche of the award as though the award were, in substance, multiple awards. The Company accounts for forfeitures as they occur. Compensation costs are recorded as general and administrative expense.

The PRSUs are issued collectively in separate tranches with individual performances periods beginning in January 2021, 2022, and 2023 respectively. For each of the performance periods the awards will vest based on the percentage of the target PRSUs subject to the performance vesting condition with 25% able to vest during the period January 1, 2021 through December 31, 2021; 25% able to vest during the period January 1, 2022 through December 31, 2022 and 50% able to vest during the period of January 1, 2023 through December 31, 2023. Vesting of PRSUs can range from zero to 200% of the target units granted based on the Company’s relative total shareholder return as compared to the total shareholder return of the Company’s performance peer group over the performance period. The fair value of each PRSU award was estimated on their grant dates using a Monte Carlo simulation. The unrecognized cost associated with the PRSUs was $0.2 million at December 31, 2021. The Company expects to recognize the unrecognized compensation cost for these awards over a weighted-average period of approximately 1.8 years.

The ranges for the assumptions used in the Monte Carlo model for the PRSUs granted are presented as follows:

	2021
Expected volatility	119.6 %
Dividend yield	0.00 %
Risk-free interest rate	0.31 %

The following table summarizes information regarding the PRSUs granted under the EIP and Legacy Amplify MIP for the period presented:

	Number of Units	Weighted-Average Grant-Date Fair Value per Unit (1)
PRSUs outstanding at December 31, 2020	—	$ —
Granted (2)	196,377	$ 1.94
Forfeited	—	$ —
Vested	—	$ —
PRSUs outstanding at December 31, 2021	196,377	$ 1.94

(1) Determined by dividing the aggregate grant date fair value of awards by the number of awards issued.
(2) The aggregate grant date fair value of PRSUs issued for the year ended December 31, 2021 was $0.4 million based on a calculated fair value price ranging from $1.24 to $2.63 per share.

2017 Non-Employee Directors Compensation Plan

As noted above, the Legacy Amplify Non-Employee Directors Compensation Plan was replaced by the EIP in May 2021.

The Legacy Amplify Non-Employee Directors Compensation Plan awards were granted in the form of nonqualified stock options, restricted stock awards, restricted stock units, and other cash-based awards and stock-based awards. To the extent that an award under the Legacy Amplify Non-Employee Directors Compensation Plan is expired, forfeited or canceled for any reason without having been exercised in full, the unexercised award would then be available again for grant under the Legacy Amplify Non-Employee Directors Compensation Plan. Awards granted generally vest annually in three equal installments on each of the first three anniversaries of the grant date, subject to the grantee's continued employment through each such vesting date.

The restricted stock units with a service vesting condition ("Board RSUs") granted are accounted for as equity-classified awards. The grant-date fair value is recognized as compensation cost on a straight-line basis over the requisite service period and forfeitures are accounted for as they occur. Compensation costs are recorded as general and administrative expense. The unrecognized cost associated with Board RSUs was less than $0.1 million at December 31, 2021. The Company expects to recognize the unrecognized compensation cost for these awards over a weighted-average period of 0.3 years.

The following table summarizes information regarding the Board RSUs granted under the Director Compensation Plan for the period presented:

	Number of Units	Weighted-Average Grant-Date Fair Value per Unit (1)
Board RSUs outstanding at December 31, 2019	16,157	$ 5.12
Granted	—	$ —
Forfeited	—	$ —
Vested	(7,259)	$ 5.12
Board RSUs outstanding at December 31, 2020	8,898	$ 5.12
Granted	—	$ —
Forfeited	—	$ —
Vested	(5,565)	$ 5.12
Board RSUs outstanding at December 31, 2021	3,333	$ 5.12

(1) Determined by dividing the aggregate grant date fair value of awards by the number of awards issued.

Compensation Expense

The following table summarizes the amount of recognized compensation expense associated with these awards that are reflected in the accompanying statements of operations for the periods presented (in thousands):

	For the Year Ended December 31, 2021	For the Year Ended December 31, 2020
Equity classified awards		
TSUs	$ 1,541	$ 267
PSUs	(130)	98
Board RSUs	16	19
PRSUs	178	—
	$ 1,605	$ 384

Note 12. Leases

The Company enters into leases for office space, warehouse space and equipment in our corporate office and operating regions as well as vehicles, compressors and surface rentals related to our business operations. In addition, the Company has offshore Southern California pipeline right-of-way use agreements. For the year ended December 31, 2021, the Company leases qualify as operating leases and the Company did not have any existing or new leases qualifying as financing leases. Most of the Company's leases, other than the Company's corporate office lease, have an initial term and may be extended on a month-to-month basis after expiration of the initial term. Most of our leases can be terminated with 30-day prior written notice. The majority of our month-to-month leases are not included as a lease liability in the Company's balance sheet because continuation of the lease is not reasonably certain. Additionally, the Company elected the short-term practical expedient to exclude leases with a term of twelve months or less.

The Company corporate office lease does not provide an implicit rate. To determine the present value of the lease payments, the Company uses an incremental borrowing rate based on the information available at the inception date. To determine the incremental borrowing rate, the Company applied a portfolio approach based on the applicable lease terms and the current economic environment. The Company uses a reasonable market interest rate for the Company office equipment and vehicle leases.

For the year ended December 31, 2021 and 2020, the Company recognized approximately $2.7 million and $2.4 million, respectively, of costs relating to the operating leases in the Consolidated Statements of Operations.

The following table presents the Company's right-of-use assets and lease liabilities for the period presented:

	December 31, 2021	December 31, 2020
	(In thousands)	
Right-of-use asset	$ 2,716	$ 2,500
Lease liabilities:		
Current lease liability	777	2,258
Long-term lease liability	2,017	266
Total lease liability	$ 2,794	$ 2,524

The following table reflects the Company's maturity analysis of the minimum lease payment obligations under non-cancelable operating leases with a remaining term in excess of one year (in thousands):

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	Office and warehouse leases	Leased vehicles and office equipment	Total
2022	$ 597	$ 262	$ 859
2023	502	240	742
2024	517	32	549
2025	532	—	532
2026 and thereafter	317	—	317
Total lease payments	2,465	534	2,999
Less: interest	186	19	205
Present value of lease liabilities	$ 2,279	$ 515	$ 2,794

The weighted average remaining lease terms and discount rate for all of the Company's operating leases for the period presented:

	December 31, 2021	December 31, 2020
Weighted average remaining lease term (years):		
Office and warehouse space	3.51	0.74
Vehicles	0.37	0.34
Office equipment	—	0.04
Weighted average discount rate:		
Office leases	2.95 %	3.41 %
Vehicles	0.59 %	0.96 %
Office equipment	0.02 %	0.17 %

Note 13. Supplemental Disclosures to the Consolidated Balance Sheet and Condensed Statement of Cash Flows

Accrued Liabilities

Current accrued liabilities consisted of the following at the dates indicated (in thousands):

	December 31, 2021	December 31, 2020
Accrued liability - pipeline incident	$ 34,417	$ —
Accrued lease operating expense	9,271	8,978
Accrued general and administrative expense	4,555	3,349
Accrued production and ad valorem tax	3,277	2,601
Accrued commitment fee and other expense	2,882	4,404
Accrued capital expenditures	1,631	173
Asset retirement obligations	1,016	424
Operating lease liability	777	2,258
Accrued current income taxes	—	110
Other	—	380
Accrued liabilities	$ 57,826	$ 22,677

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Accounts Receivable

Accounts receivable consisted of the following at the dates indicated (in thousands):

	December 31,	
	2021	2020
Oil and natural gas receivables	$ 32,428	$ 25,640
Insurance receivable - pipeline incident	55,765	—
Joint interest owners and other	5,409	6,801
Total accounts receivable	93,602	32,441
Less: allowance for doubtful accounts	(1,635)	(1,540)
Total accounts receivable, net	91,967	30,901

Supplemental Cash Flows

Supplemental cash flow for the periods presented (in thousands):

	For the Year Ended December 31,	
	2021	2020
Supplemental cash flows:		
Cash paid for interest, net of amounts capitalized	$ 8,637	$ 10,331
Cash paid for reorganization items, net	6	566
Cash paid for taxes	—	85
Noncash investing and financing activities:		
Increase (decrease) in capital expenditures in payables and accrued liabilities	1,669	(5,343)

Note 14. Related Party Transactions

Related Party Agreements

There have been no transactions between the Company and a related person in which the related person had a direct or indirect material interest for the years ended December 31, 2021 and 2020.

Secondary Public Offering of Common Stock for Selling Stockholders

On December 11, 2020, certain selling stockholders of the Company (the “Selling Stockholders”), Roth Capital Partners, LLC (the “Underwriter”) and the Company entered into an underwriting agreement, pursuant to which the Selling Stockholders agreed to sell to the Underwriter, and the Underwriter agreed to purchase from the Selling Stockholders, subject to and upon the terms and conditions set forth therein, an aggregate of 8,548,485 shares of Common Stock. The offering closed on December 15, 2020. The Company did not receive any proceeds from the sale of shares of Common Stock in the offering.

The offering was made pursuant to effective shelf registration statements (File No. 333-233677, effective October 11, 2019, and 333-215602, effective May 1, 2018) and prospectuses filed by the Company with the SEC. The offering of these securities was made only by means of a prospectus and prospectus supplement.

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Note 15. Southern California Pipeline Incident

On October 2, 2021, contractors operating under the direction of Beta, a subsidiary of the Company, observed an oil sheen on the water approximately four miles off the coast of Newport Beach, California (the “Incident”). Beta platform personnel were notified and promptly initiated the Company’s Oil Spill Response Plan, which was reviewed and approved by the BSEE’s Oil Spill Preparedness Division within the United States Department of the Interior, and which included the required notifications of specified regulatory agencies. On October 3, 2021, a Unified Command, consisting of the Company, the U.S. Coast Guard and California Department of Fish and Wildlife’s Office of Spill Prevention and Response, was established to respond to the Incident.

On October 5, 2021, the Unified Command announced that reports from its contracted commercial divers and Remotely Operated Vehicle footage indicated that a 4,000-foot section of the Company’s pipeline had been displaced with a maximum lateral movement of approximately 105 feet and that the pipeline had a 13-inch split, running parallel to the pipe. On October 14, 2021, the U.S. Coast Guard announced that it had a high degree of confidence the size of the release was approximately 588 barrels of oil, which was below the previously reported maximum estimate of 3,134 barrels. On October 16, 2021, the U.S. Coast Guard announced that it had identified the Mediterranean Shipping Company (DANIT) as a “vessel of interest” and its owner Dordellas Finance Corporation and operator Mediterranean Shipping Company, S.A. as parties in interest in connection with an anchor-dragging incident in January 2021 (the “Anchor Dragging Incident”), which occurred in close proximity to our pipeline, and that additional vessels of interest continue to be investigated. On November 19, 2021, the U.S. Coast Guard announced that it had identified the COSCO (Beijing) as another vessel involved in the Anchor Dragging Incident and named its owner Capetanissa Maritime Corporation of Liberia and its operator V.Ships Greece Ltd. as parties in interest. The cause, timing and details regarding the Incident are currently under investigation and any information regarding the Incident is preliminary.

At the height of the Incident response, the Company deployed over 1,800 personnel working under the guidance and at the direction of the Unified Command to aid in cleanup operations. As of October 14, 2021, all beaches that had been closed following the Incident have reopened. On February 2, 2022, the Unified Command announced that response and monitoring efforts have officially concluded for the Incident, and Unified Command would stand down as of such date. Amplify is grateful to its Unified Command partners for their collaboration and professionalism over the course of the response.

In response to the Incident, all operations have been suspended and the pipeline has been shut-in until the Company receives the required regulatory approvals to begin operations. On October 4, 2021, the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS) issued a Corrective Action Order (CAO) pursuant to 49 U.S.C. § 60112, which makes clear that no restart of the affected pipeline may occur until PHMSA has approved a written restart plan. Additionally, the California Coastal Commission has requested approval from the Office of Coastal Management for the National Oceanic and Atmospheric Association to conduct a Coastal Zone Management Act consistency review of the U.S. Army Corps of Engineers Nationwide Permit (NWP) 12 application for the proposed permanent repair permit. The Company is working expeditiously and cooperatively to comply with the requirements of the relevant agencies in order to gain such approvals and any other regulatory approvals that are necessary to permanently repair the pipeline and restart operations. As a result of the uncertainties related to the permitting and regulatory approval process, we can provide no assurances as to whether and when, if at all, we will be able to restart operations at the Beta field. At present, no operations are underway in the Beta field.

The Company is currently subject to a number of ongoing investigations related to the Incident by certain federal and state agencies. To date, the U.S. Coast Guard, the U.S. Bureau of Ocean Energy Management, the U.S. Department of Justice, the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration, the U.S. Department of the Interior Bureau of Safety and Environmental Enforcement, the California Department of Justice, the Orange County District Attorney, the Los Angeles County District Attorney, and the California Department of Fish & Wildlife are conducting investigations or examinations of the Incident. Other federal agencies may or have commenced investigations and proceedings, and federal agencies such as the U.S. Environmental Protection Agency may initiate enforcement actions seeking penalties and other relief under the Clean Water Act and other statutes. Amplify continues to comply with all regulatory requirements and investigations. The outcomes of these investigations and the nature of any remedies pursued will depend on the discretion of the relevant authorities and may result in regulatory or other enforcement actions, as well as civil and criminal liability.

On December 15, 2021, a federal grand jury in the Central District of California returned a federal criminal indictment against Amplify Energy Corp., Beta Operating Company, LLC, and San Pedro Bay Pipeline Company in connection with the Incident. The indictment alleges that the Company committed a misdemeanor violation of the federal Clean Water Act for negligently discharging oil into the contiguous zone of the United States. The United States Attorney's Office for the Central District of California has stated that its investigation of the Incident and related matters is ongoing. State authorities are conducting parallel criminal investigations as well. The Company is continuing to cooperate with these federal and state investigations. The outcome of these investigations is uncertain, including whether they will result in additional criminal charges.

The Company and certain of its subsidiaries have been named as defendants in approximately 14 putative class action lawsuits, which have been consolidated into a single consolidated action in the United States District Court for the Central District of California. In the consolidated action, Plaintiffs filed an amended class action complaint on January 28, 2022. The amended complaint asserted claims against us and MSC Mediterranean Shipping Company, Dordellas Finance Corp., Costamare Shipping Co. S.A., and Capetanissa Maritime Corporation of Liberia. Resolution of the consolidated case may take considerable time, and it is not possible at this time to estimate our potential liability resulting from these actions.

Under the Oil Pollution Act of 1990, 33 U.S.C. S 2701 et seq. ("OPA 90"), the Company's pipeline was designated by the U.S. Coast Guard as the source of the oil discharge and therefore the Company is financially responsible for remediation and for certain costs and economic damages as provided for in OPA 90, as well as certain natural resource damages associated with the spill and certain costs determined by federal and state trustees engaged in a joint assessment of such natural resource damages. The Company is currently processing covered claims under OPA 90 as expeditiously as possible. In addition, the Natural Resource Damage Assessment remains ongoing and therefore the extent, timing and cost related to such assessment are difficult to project. While the Company anticipates insurance will reimburse it for expenses related to the Natural Resource Damage Assessment, any potentially uncovered expenses may be material and could impact the Company's business and results of operations and could put pressure on its liquidity position going forward.

The Company currently estimates that the total costs it has incurred or will incur with respect to the Incident related to (i) actual and projected response and remediation expenses incurred under the direction of the Unified Command and (ii) estimates for certain legal fees, to be approximately $90.0 million to $110.0 million. These estimates consider currently available facts and presently enacted laws and regulations. The Company has made assumptions regarding (i) the probable and estimable amounts expected to be settled with certain vendors for response and remediation expenses and (ii) the resolution of certain third-party claims, excluding claims with respect to losses, which are not probable and reasonably estimable, and (iii) future claims and lawsuits. The Company's estimates do not include (i) the nature, extent and cost of future legal services that will be required in connection with all lawsuits, claims and other matters requiring legal or expert advice associated with the Incident, (ii) any lost revenue associated with the suspension of operations at Beta, (iii) any liabilities or costs that are not reasonably estimable at this time or that relate to contingencies where the Company currently regards the likelihood of loss as being only reasonably possible or remote and (iv) the future costs associated with the permanent repair of the pipeline and the restart of the Beta operations. The Company believes it has accrued adequate amounts for all probable and reasonably estimable costs; however, this estimate is subject to uncertainties associated with the assumptions that it has made. For example, settlements with vendors for response and remediation expenses could turn out to be significantly higher or lower than the Company has estimated. Accordingly, as the Company's assumptions and estimates may change in future periods based on future events and total costs may materially increase; therefore, the Company can provide no assurance that it will not have to accrue significant additional costs in future period with respect to the Incident.

In accordance with customary insurance practice, the Company maintains insurance policies, including loss of production income insurance, against many potential losses or liabilities arising from its operations and at costs that the Company believes to be economic. The Company regularly reviews its risk of loss and the cost and availability of insurance and revises its insurance accordingly. The Company's insurance does not cover every potential risk associated with its operations and is subject to certain exclusions and deductibles. While the Company expects its insurance policies will cover a material portion of the total aggregate costs associated with the Incident, including but not limited to response and remediation expenses, defense costs and loss of revenue resulting from suspended operations, it can provide no assurance that its coverage will adequately protect it against liability from all potential consequences, damages and losses related to the Incident and such view and understanding is preliminary and subject to change.

As of December 31, 2021, the Company has incurred total aggregate gross costs of $99.0 million, of which the Company has received or believes that it is probable that it will receive $97.4 million in insurance recoveries. The Company's net charge of $1.6 million, which is classified as "Pipeline Incident Loss" in the Company's Consolidated Statements of Operations, reflects insurance deductibles and legal costs incurred to date that are not currently expected to be recovered under an insurance policy.

Through December 31, 2021, the Company had collected $48.3 million out of approximate $97.4 million of costs that the Company believe are probable of recovery from insurance carriers, net of deductibles. Therefore as of December 31, 2021, the Company had a receivable of approximately $49.1 million for the portion of costs that the Company believe is probable of recovery from insurance, net of deductibles and amounts collected during 2021. Subsequent to December 31, 2021, for the period January 1, 2022 through March 1, 2022, the Company received insurance cost recoveries of $22.1 million.

Additionally, during 2021, the Company recognized $6.7 million related to approved LOPI insurance claims, which is classified as "Other Revenues" in the Company's Consolidated Statement of Operations. Subsequent to December 31, 2021, for the period January 1, 2022 through March 1, 2022, the Company received the entire LOPI insurance claim settlement of $6.7 million.

Note 16. Commitments and Contingencies

Litigation and Environmental

As part of our normal business activities, we may be named as defendants in litigation and legal proceedings, including those arising from regulatory and environmental matters.

Although the Company is insured against various risks to the extent the Company believes it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify it against liabilities arising from future legal proceedings.

Environmental costs for remediation are accrued based on estimates of known remediation requirements. Such accruals are based on management's best estimate of the ultimate cost to remediate a site and are adjusted as further information and circumstances develop. Those estimates may change substantially depending on information about the nature and extent of contamination, appropriate remediation technologies and regulatory approvals. Expenditures to mitigate or prevent future environmental contamination are capitalized. Ongoing environmental compliance costs are charged to expense as incurred. In accruing for environmental remediation liabilities, costs of future expenditures for environmental remediation are not discounted to their present value, unless the amount and timing of the expenditures are fixed or reliably determinable. At December 31, 2021 and 2020, the Company had no environmental reserves recorded.

Southern California Pipeline Incident

As of February 11, 2022, the Company and certain of its subsidiaries are named defendants in a putative class action pending in the United States District Court for the Central District of California. The plaintiffs seek unspecified monetary damages and certain forms of injunctive relief. We are also participating in a related claims process organized under the Oil Pollution Act of 1990, 33 U.S.C. S 2701 et seq. ("OPA 90"). Under OPA 90, a party alleged to be responsible for a discharge of oil is required to establish a claims process to pay for interim costs and damages as a result of the discharge. The OPA 90 claims process remains at a preliminary stage.

Future litigation may be necessary, among other things, to defend ourselves by determining the scope, enforceability, and validity of claims. The results of any current or future litigation cannot be predicted with certainty, and regardless of the outcome, litigation can have an adverse impact on us because of defense and settlement costs, diversion of management resources, and other factors.

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Application for Final Decree

On April 30, 2018, the Legacy Amplify debtors filed with the Bankruptcy Court a motion for a final decree and entry of an order closing the Chapter 11 cases with respect to each of the Legacy Amplify debtors other than (i) San Pedro Bay Pipeline Company, Ch. 11 Case No. 17-30249, (ii) Rise Energy Beta, LLC, Ch. 11 Case No. 17-30250, and (iii) Beta Operating Company, LLC, Ch. 11 Case No. 17-30253, (collectively, the "Closing Debtors"). On May 30, 2018, the Bankruptcy Court entered the final decree closing the Chapter 11 cases of the Closing Debtors.

On August 24, 2020, the Legacy Amplify debtors filed with the Bankruptcy Court a motion for a final decree closing the remaining Chapter 11 cases with respect to (i) San Pedro Bay Pipeline Company, Ch. 11 Case No. 17-30249, (ii) Rise Energy Beta, LLC, Ch. 11 Case No. 17-30250, and (iii) Beta Operating Company, LLC, Ch. 11 Case No. 17-30253. On September 15, 2020, the Bankruptcy Court entered the final decree closing the remaining Chapter 11 cases. Accordingly, certain expenses, gains and losses that were realized or incurred in the bankruptcy proceedings are recorded in "reorganization items, net" on the Company's Consolidated Statement of Operations.

Sinking Fund Trust Agreement

Beta Operating Company, LLC, a wholly owned subsidiary, assumed an obligation with a third party to make payments into a sinking fund in connection with its 2009 acquisition of the Company properties in federal waters offshore Southern California, the purpose of which is to provide funds adequate to decommission the portion of the San Pedro Bay Pipeline that lies within state waters and the surface facilities. Under the terms of the agreement, the operator of the properties is obligated to make monthly deposits into the sinking fund account in an amount equal to $0.25 per barrel of oil and other liquid hydrocarbon produced from the acquired working interest. Interest earned in the account stays in the account. The obligation to fund ceases when the aggregate value of the account reaches $4.3 million. As of December 31, 2021, the account balance included in restricted investments was approximately $4.3 million.

Supplemental Bond for Decommissioning Liabilities Trust Agreement

Beta has an obligation with the BOEM in connection with the 2009 acquisition of the Beta Properties. The Company supports this obligation with $161.3 million in A-rated surety bonds and $0.3 million in cash at December 31, 2021. The Company's existing bonding arrangements issued in connection with the decommissioning obligations related to our Beta Properties contain additional collateral requirements pursuant to which we may be required to post collateral at any time, on demand, at the sureties' sole discretion, which may negatively impact our liquidity position.

Pursuant to these additional collateral requirements, on December 15, 2021, the Company entered into two escrow funding agreements with its surety providers to fund interest-bearing escrow accounts on a quarterly basis to reimburse and indemnify the surety providers for any claims arising under the surety bonds related to the decommissioning of our Beta properties. As long as we continue to comply with our obligations under such escrow agreements, the surety providers party thereto have agreed to stay requests of additional collateral in the form of cash or letters of credit, certificates of deposit or other similar forms of liquid collateral. If any such additional collateral were requested, such additional collateral may negatively impact the Company's liquidity position. The obligation ceases when the aggregate value of the account reaches $172.6 million. The table below outlines our funding commitment under these agreements at December 31, 2021 (in thousands):

	Payment Due by Period						
Funding commitment	**Total**	**2022**	**2023**	**2024**	**2025**	**2026**	**Thereafter (1)**
Sinking fund payments	$ 172,601	$ 6,688	$ 8,025	$ 15,789	$ 15,789	$ 15,789	$ 110,521

(1) The remaining payments will be made during the years of 2027 through 2033.

The expense related to the surety bonds is recorded in interest expense in the Company Statement of Consolidated Operations.

Operating Leases

We have leases for offshore Southern California pipeline right-of-way use as well as office space in our operating regions. We also lease equipment, compressors and incur surface rentals related to its business operations.

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For the years ended December 31, 2021 and 2020, the Company recognized \$7.6 million and \$8.3 million of rent expense, respectively.

See Note 12 for the minimum lease payment obligations under non-cancelable operating leases with a remaining term in excess of one year.

Purchase Commitments

At December 31, 2021, the Company had a CO_2 purchase commitment with a third party associated with its Wyoming Bairoil properties. The price we will pay for CO_2 generally varies depending on the amount of CO_2 delivered and the price of oil. The table below outlines its purchase commitments under these contracts based on pricing at December 31, 2021 (in thousands):

	Payment or Settlement Due by Period						
Purchase commitment	**Total**	**2022**	**2023**	**2024**	**2025**	**2026**	**Thereafter**
CO_2 minimum purchase commitment	\$ 3,975	\$ 3,975	\$ —	\$ —	\$ —	\$ —	\$ —

Minimum Volume Commitment

At December 31, 2021, the Company had long-term minimum volume commitments with third parties associated with a certain portion of its properties located in Oklahoma and East Texas. The table below outlines the future payment commitments associated with the minimum volume commitment plus any applicable fee for not meeting the minimum volume commitment (in thousands):

	Payment or Settlement Due by Period (1)						
	Total	**2022**	**2023**	**2024**	**2025**	**2026**	**Thereafter**
Minimum volume commitment	\$ 15,196	\$ 12,283	\$ 2,913	\$ —	\$ —	\$ —	\$ —

(2) The amounts in the table do not reflect costs adjusted for inflation.

The Company is party to a gas purchase, gathering and processing contract in Oklahoma, which includes certain minimum NGL commitments. To the extent the Company does not deliver natural gas volumes in sufficient quantities to generate, when processed, the minimum levels of recovered NGLS, it would be required to reimburse the counterparty an amount equal to the sum of the monthly shortfall, if any, multiplied by a fee. The Company is not meeting the minimum volume required under these contractual provisions. The commitment fee expense for the year ended December 31, 2021 and 2020, was approximately \$1.6 million and \$2.1 million. The minimum volume commitment for Oklahoma ends on June 30, 2023.

The Company is party to a gas purchase, gathering and processing contract in East Texas, which includes certain minimum gas commitments. The Company is not meeting the minimum volume required under this contractual provision. The commitment fee expense for the year ended December 31, 2021 and 2020, was approximately \$2.0 million and \$1.8 million, respectively. The minimum volume commitment for East Texas ends on November 30, 2022.

Note 17. Income Tax

Amplify Energy is a corporation and, as a result, is subject to U.S. federal, state, and local income taxes.

On March 11, 2021, the President of the United States signed the ARP Act, to respond to the COVID-19 emergency and address its economic effects. Additionally, the President signed the Infrastructure Investment and Jobs Act “IIJ Act” on November 15, 2021 to authorize funds for Federal-aid highways, highway safety programs, and transit programs, and for other purposes. The enactment of the ARP Act and IIJ Act did not result in any material impact on the Company’s current year income tax provision.

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The components of income tax benefit (expense) are as follows:

	For the Year Ended December 31, 2021	For the Year Ended December 31, 2020
	(In thousands)	
Current taxes:		
Federal	$ —	$ (5)
State	—	(110)
Total current income tax benefit (expense)	—	(115)
Deferred taxes:		
Federal	—	—
State	—	—
Total deferred income tax benefit (expense)	—	—
Total income tax benefit (expense)	$ —	$ (115)

The actual income tax benefit (expense) differs from the expected amount computed by applying the federal statutory corporate tax rate of 21% in 2021 and in 2020 as follows:

	For the Year Ended December 31, 2021	For the Year Ended December 31, 2020
	(In thousands)	
Expected tax benefit (expense) at federal statutory rate	$ 6,734	$ 97,423
State income tax benefit (expense), net of federal benefit	447	6,189
Non-deductible expenses	(64)	(45)
Changes in valuation allowances	3,192	(110,445)
State rate change, net of federal benefit	(10,192)	6,100
State prior year adjustment	(1,281)	—
Non-cash compensation	8	(137)
PPP loan forgiveness	1,158	—
Other	(2)	800
Total income tax benefit (expense)	$ —	$ (115)

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The Company's deferred tax position reflects the net tax effects of the temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax reporting. Significant components of the deferred tax assets and liabilities are as follows (in thousands):

	December 31,	
	2021	2020
Deferred income tax assets:		
Property, Plant & Equipment	$ 94,439	$ 115,695
Net operating loss carryforward	178,279	174,479
Derivatives	14,438	2,448
Disallowed interest expense	5,579	5,388
Accrued liabilities	1,592	1,226
Other	3,469	1,717
Total deferred income tax assets:	297,796	300,953
Valuation allowance	(297,195)	(300,386)
Net deferred income tax assets	601	567
Deferred income tax liabilities:		
Derivatives	$ —	$ —
Other	601	567
Total deferred income tax liabilities	601	567
Net deferred income tax liabilities	$ —	$ —

As of December 31, 2021, the Company had approximately $777.6 million of federal net operating loss ("NOL") carryovers, of which $757.0 million have no expiration date and the remaining will expire in year 2037. In connection with the merger with Midstates in 2019, the Company is subject to IRC §382 loss limitation on pre-merger NOL and tax attributes. The amount of 2021 federal NOL carryover generated post-merger, and not subject to §382 loss limitation, is $32.2 million. As of December 31, 2021, the Company had approximately $429.8 million of state net operating loss carryovers, of which $376.3 million have no expiration period, and the remaining will expire in varying amounts beginning in 2037.

In assessing deferred tax assets, the Company considers whether a valuation allowance should be recorded for some or all of the deferred tax assets which may not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which the temporary differences become deductible. Among other items, the Company considers the scheduled reversal of deferred tax liabilities, projected future taxable income and available tax planning strategies. A valuation allowance is established against deferred tax assets for which management believes realization is considered to be more likely than not that all of the deferred tax assets will not be realized. As of December 31, 2021, a valuation allowance of $297.2 million had been recorded, which is an increase to the valuation allowance of $3.2 million from the prior year.

Uncertain Income Tax Position. The Company must recognize the tax effects of any uncertain tax positions that the Company may adopt if the position taken by us is more likely than not sustainable based on its technical merits. For those benefits to be recognized, an income tax position must be more-likely-than-not to be sustained upon examination by taxing authorities. The Company had no unrecognized tax benefits as of December 31, 2021.

Tax Audits and Settlements. The Company's income tax years 2018 through 2020 remain open and subject to examination by the Internal Revenue Service (IRS). For state and local jurisdictions, the Company's 2017 through 2020 tax years remain open and subject to examination where it conducts operations. In certain jurisdictions where the Company operates through more than one legal entity, each of which may have different open years subject to examination.

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Note 18. Supplemental Oil and Gas Information (Unaudited)

Capitalized Costs Relating to Oil and Natural Gas Producing Activities

The total amount of capitalized costs relating to oil and natural gas producing activities and the total amount of related accumulated depreciation, depletion and amortization is as follows at the dates indicated.

	December 31,	
	2021	2020
	(In thousands)	
Evaluated oil and natural gas properties	$ 799,532	$ 775,167
Support equipment and facilities	145,324	142,208
Accumulated depletion, depreciation, and amortization	(625,754)	(602,861)
Total	$ 319,102	$ 314,514

Costs Incurred in Oil and Natural Gas Property Acquisition, Exploration and Development Activities

Costs incurred in property acquisition, exploration and development activities were as follows for the periods indicated:

	For the Year Ended December 31,	
	2021	2020
	(In thousands)	
Property acquisition costs, proved	$ 3	$ 42
Property acquisition costs, unproved	—	(49,307)
Exploration	—	—
Development	27,478	29,543
Total	$ 27,481	$ (19,722)

Standardized Measure of Discounted Future Net Cash Flows from Proved Reserves

As required by the FASB and SEC, the standardized measure of discounted future net cash flows presented below is computed by applying first-day-of-the-month average prices, year-end costs and legislated tax rates and a discount factor of 10 percent to proved reserves. We do not believe the standardized measure provides a reliable estimate of the Company's expected future cash flows to be obtained from the development and production of its oil and gas properties or of the value of its proved oil and gas reserves. The standardized measure is prepared on the basis of certain prescribed assumptions including first-day-of-the-month average prices, which represent discrete points in time and, therefore, may cause significant variability in cash flows from year to year as prices change.

Oil and Natural Gas Reserves

Users of this information should be aware that the process of estimating quantities of "proved" and "proved developed" oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various reservoirs make these estimates generally less precise than other estimates included in the financial statement disclosures.

AMPLIFY ENERGY CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

We engaged CG&A to prepare our reserves estimates for all of our estimated proved reserves at December 31, 2021 and 2020. All proved reserves are located in the United States and all prices are held constant in accordance with SEC rules.

The weighted-average benchmark product prices used for valuing the reserves are based upon the average of the first-day-of-the-month price for each month within the period January through December of each year presented:

	2021	2020
Oil ($/Bbl):		
WTI (1)	$ 66.56	$ 39.57
NGL ($/Bbl):		
WTI (1)	$ 66.56	$ 39.57
Natural Gas ($/MMbtu):		
Henry Hub (2)	$ 3.60	$ 1.99

(1) The weighted average WTI price was adjusted by lease for quality, transportation fees, and a regional price differential.
(2) The weighted average Henry Hub price was adjusted by lease for energy content, compression charges, transportation fees, and regional price differentials.

The following tables set forth estimates of the net reserves for the periods indicated:

	For the Year Ended December 31, 2021			
	Oil (MBbls)	Gas (MMcf)	NGLs (MBbls)	Total (MBoe)
Proved developed and undeveloped reserves:				
Beginning of year	46,676	274,139	21,484	113,849
Extensions and discoveries	746	4,283	215	1,674
Production	(3,351)	(23,808)	(1,430)	(8,747)
Sale of minerals in place	(3)	(274)	(12)	(61)
Revision of previous estimates	933	60,010	3,580	14,515
End of year	45,001	314,350	23,837	121,230
Proved developed reserves (1):				
Beginning of year	35,613	252,218	19,009	96,658
End of year	43,857	309,794	23,574	119,063
Proved undeveloped reserves (2):				
Beginning of year	11,063	21,921	2,475	17,191
End of year	1,144	4,556	263	2,167

(1) Our reserves related to our Beta properties have been reclassified as proved developed non-producing at December 31, 2021.
(2) Change to the Company's development plan has resulted in removal of PUD locations in Oklahoma, Rockies and California.

	For the Year Ended December 31, 2020			
	Oil (MBbls)	Gas (MMcf)	NGLs (MBbls)	Total (MBoe)
Proved developed and undeveloped reserves:				
Beginning of period	70,772	377,869	29,252	163,002
Extensions and discoveries	291	655	61	461
Production	(3,887)	(27,473)	(1,725)	(10,190)
Revision of previous estimates	(20,500)	(76,912)	(6,104)	(39,424)
End of period	46,676	274,139	21,484	113,849
Proved developed reserves:				
Beginning of period	53,476	320,731	23,646	130,577
End of period	35,613	252,218	19,009	96,658
Proved undeveloped reserves:				
Beginning of period	17,296	57,138	5,606	32,425
End of period	11,063	21,921	2,475	17,191

Noteworthy amounts included in the categories of proved reserve changes in the above tables include:

- The 7.4 MMBoe increase in reserves for the year ended December 31, 2021 is primarily due to a 30.6 MMBoe increase as a result of changes in commodity pricing offset by a 16 MMBoe reduction due to removed PUD locations in Oklahoma, Rockies and California. The Company has shifted its resources to returning Beta to production and as a result has modified future PUD development plans. The Company also had 1.7 MMBoe of extension and discoveries primarily related to wells in progress at year end in Eagle Ford and East Texas, a 1.2 MMBoe reduction due to an increase in maintenance costs and a 0.9 MMBoe upward technical revision.

- The 49.2 MMBoe reduction in reserves for the year ended December 31, 2020 is primarily due to a 50.1 MMBoe downward pricing revision as a result of changes in commodity pricing, partially offset by a 4.5 MMBoe upward revision due to lower maintenance costs, a 2.4 MMBoe upward revision due to Special Case Royalty Relief on our offshore Southern California assets and a 3.7 MMBoe upward technical revision. Additionally, the Company added 0.46 MMBoe during the year ended December 31, 2020 due to extensions and discoveries.

A variety of methodologies are used to determine our proved reserve estimates. The principal methodologies employed are reservoir simulation, decline curve analysis, volumetric, material balance, advance production type curve matching, petro-physics/log analysis and analogy. Some combination of these methods is used to determine reserve estimates in substantially all of our fields.

The standardized measure of discounted future net cash flows is as follows:

	For the Year Ended December 31,	
	2021	2020
	(In thousands)	
Future cash inflows	$ 4,569,313	$ 2,410,260
Future production costs (1)	(2,691,875)	(1,589,945)
Future development costs (1)	(231,040)	(375,146)
Future income tax expense	—	—
Future net cash flows for estimated timing of cash flows	1,646,398	445,169
10% annual discount for estimated timing of cash flows	(726,553)	(147,358)
Standardized measure of discounted future net cash flows	$ 919,845	$ 297,811

(1) For the year ended December 31, 2021 and 2020, onshore abandonment costs are included in future production cost and offshore abandonment costs are included in future development costs.

AMPLIFY ENERGY CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves

The following is a summary of the changes in the standardized measure of discounted future net cash flows for the proved oil and natural gas reserves during each of the years in the two year period presented:

	For the Year Ended December 31,	
	2021	2020
	(In thousands)	
Beginning of year	$ 297,811	$ 916,561
Sale of oil and natural gas produced, net of production costs	(171,326)	(47,687)
Sale of minerals in place	(45)	—
Extensions and discoveries	17,035	3,687
Changes in prices and costs	572,897	(548,429)
Previously estimated development costs incurred	45,298	49,144
Net changes in future development costs	113,546	89,997
Revisions of previous quantities	46,271	(150,245)
Accretion of discount	29,781	91,657
Change in production rates and other	(31,423)	(106,874)
End of year	$ 919,845	$ 297,811

Exhibit 21.1

SUBSIDIARIES OF AMPLIFY ENERGY CORP.

Name	Jurisdiction
Amplify Energy Holdings LLC	Delaware
Amplify Acquisitionco LLC	Delaware
Amplify Energy Services LLC	Delaware
Amplify Energy Operating LLC	Delaware
Amplify Energy Holdco LLC	Delaware
Amplify Oklahoma Operating LLC (f/k/a Midstates Petroleum Company LLC)	Delaware
Beta Operating Company, LLC	Delaware
San Pedro Bay Pipeline Company	California

EXHIBIT 23.1

CAWLEY, GILLESPIE & ASSOCIATES, INC.
PETROLEUM CONSULTANTS

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

Cawley, Gillespie & Associates, Inc., hereby consents to the references to our firm, in the context in which they appear, and to the references to and the incorporation by reference of our summary report dated January 22, 2022 included in the Annual Report on Form 10-K of Amplify Energy Corp. for the fiscal year ended December 31, 2021, as well as in the notes to the financial statements included therein. We hereby further consent to the incorporation by reference of the references to our firm, in the context in which they appear, and to our summary report dated January 22, 2022, into Amplify Energy Corp. previously filed registration statements on Form S-8 (No. 333-257071), Form S-3 (No. 333-254149), Form S-3 (No. 333-233677), and Form S-3 (No. 333-215602).

Matt Regan

Matthew K. Regan
Vice President
Cawley, Gillespie & Associates, Inc.
TEXAS REGISTERED ENGINEERING FIRM F-693
Fort Worth, Texas
Austin, Texas
Houston, Texas
March 9, 2022

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in registration statements on Form S-8 (File No. 333-257071), Form S-3 (File No. 333-254149), Form S-3 (File No. 333-233677) and Form S-3 (File No. 333-215602) of Amplify Energy Corp. of our report dated March 9, 2022, relating to the financial statements of Amplify Energy Corp. appearing in this Annual Report on Form 10-K for the year ended December 31, 2021.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 9, 2022

Exhibit 31.1

**CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED**

I, Martyn Willsher, certify that:

1. I have reviewed this Annual Report on Form 10-K of Amplify Energy Corp. (the “registrant”);

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

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

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

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

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

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

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

5. The registrant’s other certifying officer(s) 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: March 9, 2022

/s/ Martyn Willsher
Martyn Willsher
President and Chief Executive Officer
Amplify Energy Corp.

Exhibit 31.2

**CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED**

I, Jason McGlynn, certify that:

1. I have reviewed this Annual Report on Form 10-K of Amplify Energy Corp. (the “registrant”);

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

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

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

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

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

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

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

5. The registrant’s other certifying officer(s) 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: March 9, 2022

/s/ Jason McGlynn
Jason McGlynn
Senior Vice President and Chief Financial Officer
Amplify Energy Corp.

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 Annual Report on Form 10-K of Amplify Energy Corp. (the “Company”), as filed with the Securities and Exchange Commission on the date hereof (the “Report”), the undersigned, Martyn Willsher, President and Chief Executive Officer of Amplify Energy Corp. and Jason McGlynn, Senior Vice President and Chief Financial Officer of Amplify Energy Corp., certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to their knowledge:

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

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

Date: March 9, 2022	/s/ Martyn Willsher Martyn Willsher President and Chief Executive Officer Amplify Energy Corp.
Date: March 9, 2022	/s/ Jason McGlynn Jason McGlynn Senior Vice President and Chief Financial Officer Amplify Energy Corp.

The foregoing certifications are being furnished as an exhibit to the Report pursuant to Item 601(b)(32) of Regulation S-K and Section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code) and, accordingly, are not being filed as part of the Report for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and are not incorporated by reference into any filing of the Company, whether made before or after the date hereof, regardless of any general incorporation language in such filing.

Exhibit 99.1

EVALUATION SUMMARY

AMPLIFY ENERGY CORP. INTERESTS

VARIOUS OIL AND GAS PROPERTIES IN THE UNITED STATES

TOTAL PROVED RESERVES

AS OF DECEMBER 31, 2021

SEC PRICE CASE

CG&A

CAWLEY, GILLESPIE & ASSOCIATES, INC.
PETROLEUM CONSULTANTS

EVALUATION SUMMARY

AMPLIFY ENERGY CORP. INTERESTS

VARIOUS OIL AND GAS PROPERTIES IN THE UNITED STATESTOTAL

PROVED RESERVES

AS OF DECEMBER 31, 2021

SEC PRICE CASE

CAWLEY, GILLESPIE & ASSOCIATES, INC.
PETROLEUM CONSULTANTS
TEXAS REGISTERED ENGINEERING FIRM F-693

W. Todd Brook

STATE OF TEXAS
W. TODD BROOKER
83462
LICENSED
PROFESSIONAL ENGINEER

Matt Regan

STATE OF TEXAS
MATTHEW K. REGAN
113228
LICENSED
PROFESSIONAL ENGINEER

VICE PRESIDENT

CAWLEY, GILLESPIE & ASSOCIATES, INC.

PETROLEUM CONSULTANTS

13640 BRIARWICK DRIVE, SUITE 100 306 WEST SEVENTH STREET, SUITE 302 1000 LOUISIANA STREET, SUITE 1900AUSTIN,
TEXAS 78729-1107 FORT WORTH, TEXAS 76102-4987 HOUSTON, TEXAS 77002-5008512-249-7000
713-651-9944
817- 336-2461
www.cgaus.com

January 22, 2022

Amplify Energy Corp.
500 Dallas Street, Suite 1700
Houston, Texas 77002

Re: Evaluation Summary
Amplify Energy Corp. Interests
Total Proved Reserves As of
December 31, 2021

Pursuant to the Guidelines of the Securities and Exchange Commission forReporting Corporate Reserves and Future Net Revenue

Ladies and Gentlemen:

As requested, this report was completed on January 22, 2022 for Amplify Energy Corp. ("Amplify") for the purpose of public disclosure by Amplify in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations. We evaluated 100% of Amplify reserves, which are made up of oil and gas properties in Alabama, federal waters offshore California, Louisiana, Oklahoma, Texas and Wyoming. This report, with an effective date of December 31, 2021, was prepared using constant prices and costs and conforms to the guidelines of the *Securities and Exchange Commission* (SEC). The results of this evaluation are presented below:

		Proved Developed Producing	Proved Developed Non-Producing	Proved Developed	Proved Undeveloped	Total Proved
Net Reserves						
Oil	- MBBL	29,945.4	13,912.4	43,857.9	1,143.9	45,001.7
Gas	- MMCF	267,925.0	41,868.6	309,793.6	4,556.8	314,350.3
NGL	- MBBL	20,720.5	2,852.6	23,573.1	263.2	23,836.3
Revenue						
Oil	- M$	1,873,334.0	879,465.5	2,752,799.5	74,959.5	2,827,759.1
Gas	- M$	840,878.9	122,481.2	963,360.0	15,486.3	978,846.5
NGL	- M$	681,888.3	73,459.7	755,348.0	7,359.9	762,708.0
Severance Taxes	- M$	205,178.2	20,972.2	226,150.4	4,624.1	230,774.5
Ad Valorem Taxes	- M$	137,147.7	5,631.8	142,779.5	1,426.8	144,206.2
Operating Expenses (1)	- M$	1,627,236.6	615,581.9	2,242,818.7	19,235.7	2,262,054.4
Investments (2)	- M$	66,842.3	192,810.3	259,652.6	26,226.8	285,879.4
Net Cash Flows	- M$	1,359,696.8	240,410.0	1,600,106.5	46,292.3	1,646,399.1
Discounted @ 10% ***(Present Worth)***	**- M$**	**705,696.6**	**189,015.2**	**894,711.8**	**25,133.3**	**919,845.2**

(1) Operating expense includes but is not limited to, direct operating costs, maintenance, well service, compressor service, tubing/pump repair, compression fees, gathering expenses, transportation costs andwater disposal costs
(2) Investments includes but is not limited to, re-completion costs, future drilling costs, newlift installations, pumping units and the costs for plugging and salvage value of equipment at abandonment

Future revenue is prior to deducting state production taxes and ad valorem taxes. Future net cash flow isafter deducting these taxes, future capital costs and operating expenses, but before consideration of federal income taxes. In accordance with SEC guidelines, the future net cash flow has been discounted at an annual rate of ten percent to determine its “present worth”. The present worth is shown to indicate the effect of time on the value of money and should not be construed as being the fair market value of the properties.

The oil reserves include oil and condensate. Oil and NGL volumes are expressed in barrels (42 U.S. gallons). Gas volumes are expressed in thousands of standard cubic feet (Mcf) at contract temperature and pressure base.

Our estimates are for proved reserves only and do not include any probable or possible reserves nor have any values been attributed to interest in acreage beyond the location for which undeveloped reserves have been estimated. The Proved Developed category is the summation of the Proved Developed Producing and Proved Developed Non-Producing estimates.

Hydrocarbon Pricing

The base oil and gas prices calculated for December 31, 2021 were $66.56 per barrel and $3.598 per MMBTU, respectively. As specified by the SEC, a company must use a 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. The base oil price is based upon WTI-Cushing spot prices (EIA) during 2021 and the base gas price is based upon Henry Hub spot prices (Platt’s Gas Daily) during 2021.

The base prices were adjusted for differentials on a per-property basis, which may include local basis differentials, transportation, gas shrinkage, gas heating value (BTU content) and/or crude quality and gravity corrections. After these adjustments, the net realized prices over the life of the proved properties was estimated to be $62.837 per barrel for oil, $3.114 per MCF for gas and $31.998 per barrel for natural gas liquids. All economic factors were held constant in accordance with SEC guidelines.

Economic Parameters

Ownership was accepted as furnished and has not been independently confirmed. Oil and gas price differentials, gas shrinkage, ad valorem taxes, severance taxes, lease operating expenses and investments were calculated and prepared by Amplify and were thoroughly reviewed by us for accuracy and completeness. Lease operating expenses were calculated based on historical lease operating statements. All economic parameters, including lease operating expenses and investments, were held constant (not escalated) throughout the life of these properties. Operating expense includes but is not limited to, direct operating costs, maintenance, well service, compressor service, tubing/pump repair, compression fees, gathering expenses, transportation costs and water disposal costs. Investments includes but is not limited to, re-completion costs, future drilling costs, new lift installations, pumping units and the costs for plugging and salvage value of equipment at abandonment.

SEC Conformance and Regulations

The reserve classifications and the economic considerations used herein conform to the criteria of the SEC as defined in the Appendix. The reserves and economics are predicated on regulatory agency classifications, rules, policies, laws, taxes and royalties currently in effect except as noted herein. Amplify’s operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include matters relating to land tenure, drilling, production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of reserves actually recovered and amounts of income actually received to differ significantly from the estimated quantities.

This evaluation includes 70 commercial proved undeveloped locations. There are 67 wells in the EGLFD area (Texas) and 3 wells in the ETX_NLA area (Texas). Each of the drilling locations proposed conform to the proved undeveloped standards as set forth by the SEC. In our opinion, Amplify has indicated they have every intent to complete this development plan as scheduled. Furthermore, Amplify has indicated that they have the proper company staffing, financial backing and prior development success to ensure this development plan will be fully executed.

Reserve Estimation Methods

The methods employed in estimating reserves are described in the Appendix. Reserves for proved developed producing wells were estimated using production performance methods for the vast majority of properties. Certain new producing properties with very little production history were forecast using a combination of production performance and analogy to offset production, both of which are considered to provide a relatively high degree of accuracy.

Non-producing and undeveloped reserve estimates were forecast using either volumetric or analogy methods, or a combination of both. These methods provide a relatively high degree of accuracy for predicting proved developed non-producing and proved undeveloped reserves for Amplify properties, due to the maturenature of their properties targeted for development and an abundance of subsurface control data. Theassumptions, data, methods and procedures used herein are appropriate for the purpose served by this report.

General Discussion

The estimates and forecasts were based upon interpretations of data furnished by your office and available from our files. To some extent information from public records has been used to check and/or supplement these data. The basic engineering and geological data were subject to third party reservations andqualifications. Nothing has come to our attention, however, that would cause us to believe that we are not justified in relying on such data. All estimates represent our best judgment based on the data available at the time of preparation. Reserves estimates will generally be revised as additional geologic or engineering data become available or as economic conditions change. Moreover, estimates of reserves may increase or decrease as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. As a result, the estimates of oil and gas reserves have an intrinsic uncertainty. The reserves included in this report are therefore estimates only and should not be construed as being exact quantities. They may or may not be actually recovered, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts. The Beta field was scheduled to return to production on 07/2022 as per Amplify's best estimate and at their direction.

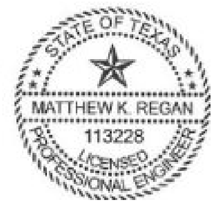
An on-site field inspection of the properties has not been performed. The mechanical operation or condition of the wells and their related facilities have *not* been examined nor have the wells been tested by Cawley, Gillespie & Associates, Inc. Possible environmental liability related to the properties has not been investigated nor considered. The cost of plugging and the salvage value of equipment at abandonment have been included on commercial proved wells at the end of the economic life of the cases in the SEC pricing evaluation. The cost of plugging and salvage value of equipment at abandonment have not been included elsewhere herein.

Cawley, Gillespie & Associates, Inc. is a Texas Registered Engineering Firm (F-693), made up of independent registered professional engineers and geologists that have provided petroleum consulting services tothe oil and gas industry for over 60 years. This evaluation was supervised by W. Todd Brooker, President at Cawley, Gillespie & Associates, Inc. and a State of Texas Licensed Professional Engineer (License #83462). Wedo not own an interest in the properties or Amplify Energy Corp. and are not employed on a contingent basis.

We have used all methods and procedures that we consider necessary under the circumstances to prepare thisreport. Our work-papers and related data utilized in the preparation of these estimates are available in our office.

Yours very truly,

Matt Regan



CAWLEY, GILLESPIE & ASSOCIATES, INC.

APPENDIX

Methods Employed in the Estimation of Reserves

The four methods customarily employed in the estimation of reserves are (1) *production performance*, (2) *material balance*, (3) *volumetric* and (4) *analogy*. Most estimates, although based primarily on one method, utilize other methods depending on the nature and extent of the data available and the characteristics of the reservoirs.

Basic information includes production, pressure, geological and laboratory data. However, a large variation exists in the quality, quantity and types of information available on individual properties. Operators are generally required by regulatory authorities to file monthly production reports and may be required to measure and report periodically such data as well pressures, gas-oil ratios, well tests, etc. As a general rule, an operator has complete discretion in obtaining and/or making available geological and engineering data. The resulting lack of uniformity in data renders impossible the application of identical methods to all properties, and may result in significant differences in the accuracy and reliability of estimates.

A brief discussion of each method, its basis, data requirements, applicability and generalization as to its relative degree of accuracy follows:

Production performance. This method employs graphical analyses of production data on the premise that all factors which have controlled the performance to date will continue to control and that historical trends can be extrapolated to predict future performance. The only information required is production history. Capacity production can usually be analyzed from graphs of rates versus time or cumulative production. This procedure is referred to as "decline curve" analysis. Both capacity and restricted production can, in some cases, be analyzed from graphs of producing rate relationships of the various production components. Reserve estimates obtained by this method are generally considered to have a relatively high degree of accuracy with the degree of accuracy increasing as production history accumulates.

Material balance. This method employs the analysis of the relationship of production and pressure performance on the premise that the reservoir volume and its initial hydrocarbon content are fixed and that this initial hydrocarbon volume and recoveries therefrom can be estimated by analyzing changes in pressure with respect to production relationships. This method requires reliable pressure and temperature data, production data, fluid analyses and knowledge of the nature of the reservoir. The material balance method is applicable to all reservoirs, but the time and expense required for its use is dependent on the nature of the reservoir and its fluids. Reserves for depletion type reservoirs can be estimated from graphs of pressures corrected for compressibility versus cumulative production, requiring only data that are usually available. Estimates for other reservoir types require extensive data and involve complex calculations most suited to computer models which makes this method generally applicable only to reservoirs where there is economic justification for its use. Reserve estimates obtained by this method are generally considered to have a degree of accuracy that is directly related to the complexity of the reservoir and the quality and quantity of data available.

Volumetric. This method employs analyses of physical measurements of rock and fluid properties to calculate the volume of hydrocarbons in-place. The data required are well information sufficient to determine reservoir subsurface datum, thickness, storage volume, fluid content and location. The volumetric method is most applicable to reservoirs which are not susceptible to analysis by production performance or material balance methods. These are most commonly newly developed and/or no-pressure depleting reservoirs. The amount of hydrocarbons in-place that can be recovered is not an integral part of the volumetric calculations but is an estimate inferred by other methods and a knowledge of the nature of the reservoir. Reserve estimates obtained by this method are generally considered to have a low degree of accuracy; but the degree of accuracy can be relatively high where rock quality and subsurface control is good and the nature of the reservoir is uncomplicated.

Analogy. This method, which employs experience and judgment to estimate reserves, is based on observations of similar situations and includes consideration of theoretical performance. The analogy method is a common approach used for "resource plays," where an abundance of wells with similar production profiles facilitates the reliable estimation of future reserves with a relatively high degree of accuracy. The analogy method may also be applicable where the data are insufficient or so inconclusive that reliable reserve estimates cannot be made by other methods. Reserve estimates obtained in this manner are generally considered to have a relatively low degree of accuracy.

Much of the information used in the estimation of reserves is itself arrived at by the use of estimates. These estimates are subject to continuing change as additional information becomes available. Reserve estimates which presently appear to be correct may be found to contain substantial errors as time passes and new information is obtained about well and reservoir performance.

Reserve Definitions and Classifications

The Securities and Exchange Commission, in SX Reg. 210.4-10 dated November 18, 1981, as amended on September 19, 1989 and January 1, 2010, requires adherence to the following definitions of oil and gas reserves:

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

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

"(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

"(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

"(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

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

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

"(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

"(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

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

"(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

"(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

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

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

"(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

"(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

"(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

"(iv) See also guidelines in paragraphs (17)(iv) and (17)(vi) of this section (below).

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

"(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

"(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

"(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

"(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

"(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

"(vi) Pursuant to paragraph (22)(iii) of this section (above), where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations."

Instruction 4 of Item 2(b) of Securities and Exchange Commission Regulation S-K was revised January 1, 2010 to state that "a registrant engaged in oil and gas producing activities shall provide the information required by Subpart 1200 of Regulation S–K." This is relevant in that Instruction 2 to paragraph (a)(2) states: "The registrant is *permitted, but not required*, to disclose probable or possible reserves pursuant to paragraphs (a)(2)(iv) through (a)(2)(vii) of this Item."

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

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

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Professional Qualifications of Primary Technical Person

The evaluation summarized by this report was conducted by a proficient team of geologists and reservoir engineers who integrate geological, geophysical, engineering and economic data to produce high quality reserve estimates and economic forecasts. This report was supervised by Todd Brooker, President of Cawley, Gillespie & Associates (CG&A).

Prior to joining CG&A, Mr. Brooker worked in Gulf of Mexico drilling and production engineering at Chevron. Mr. Brooker has been an employee of CG&A since 1992. His responsibilities include reserveand economic evaluations, fair market valuations, field studies, pipeline resource studies and acquisition/divestiture analysis. His reserve reports are routinely used for public company SEC disclosures. His experience includes significant projects in both conventional and unconventional resources in every major U.S. producing basin and abroad, including oil and gas shale plays, coalbed methane fields, waterfloods and complex, faulted structures.

Mr. Brooker graduated with honors from the University of Texas at Austin in 1989 with a Bachelor of Science degree in Petroleum Engineering, and is a registered Professional Engineer in the State of Texas.He is also a member of the Society of Petroleum Engineers (SPE) and the Society of Petroleum Evaluation Engineers (SPEE).

Based on his educational background, professional training and more than 20 years of experience, Mr. Brooker and CG&A continue to deliver professional, ethical and reliable engineering and geological services to the petroleum industry.

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