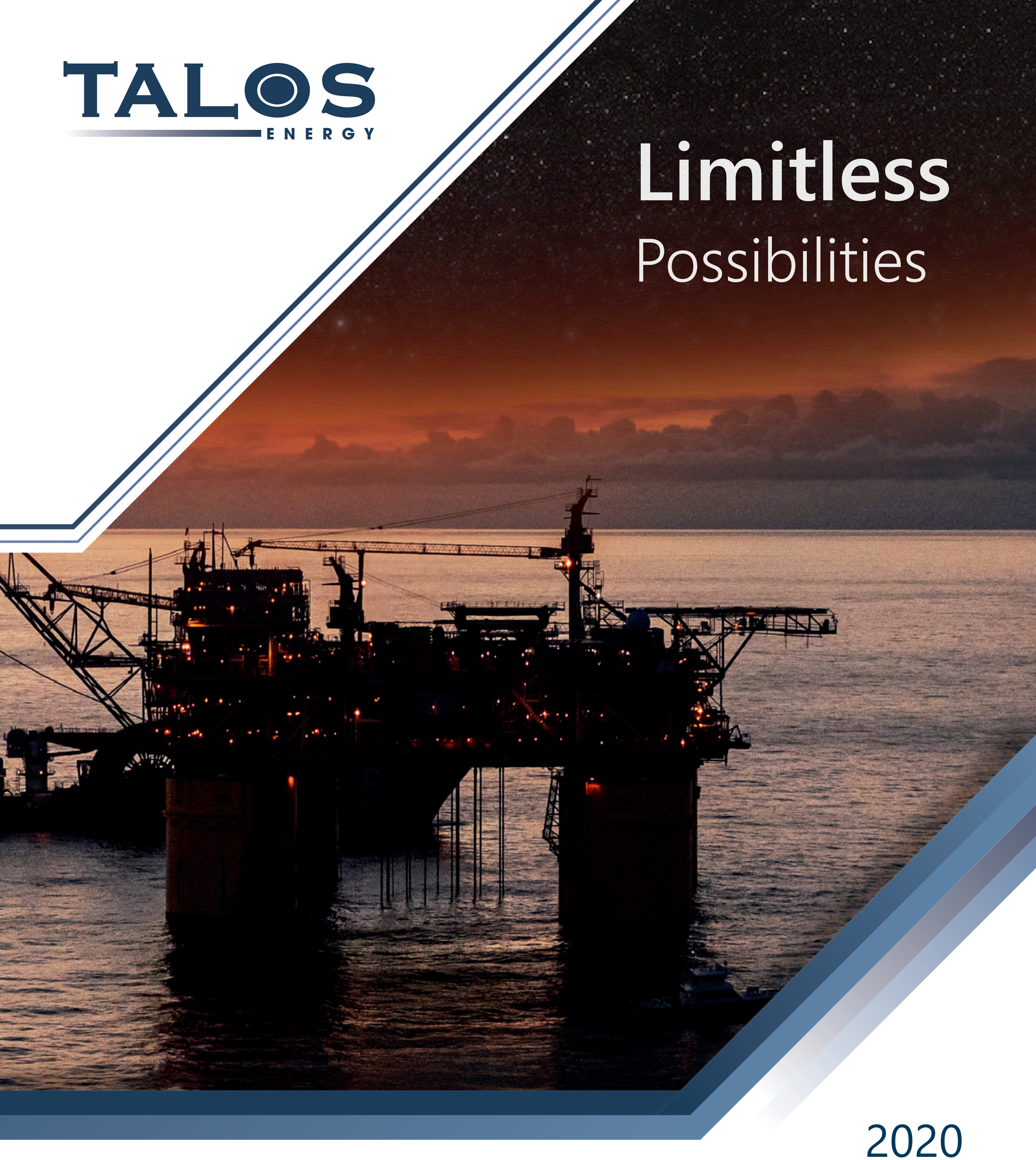
Limitless
Possibilities



2020 ANNUAL REPORT

Talos Energy

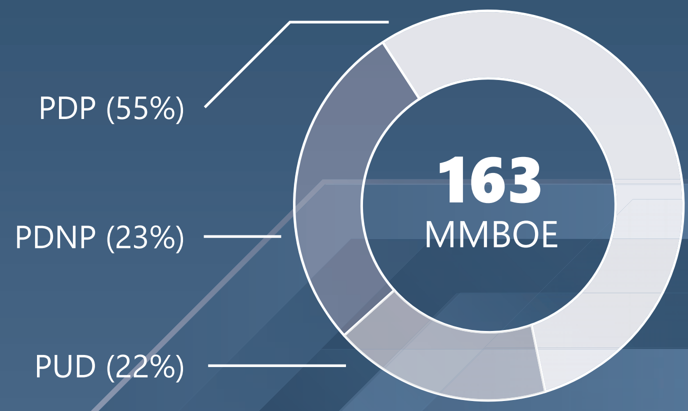
RESERVES AT A GLANCE

Talos Energy is a leading offshore energy company focused on oil and gas exploration and production in the United States Gulf of Mexico and offshore Mexico.

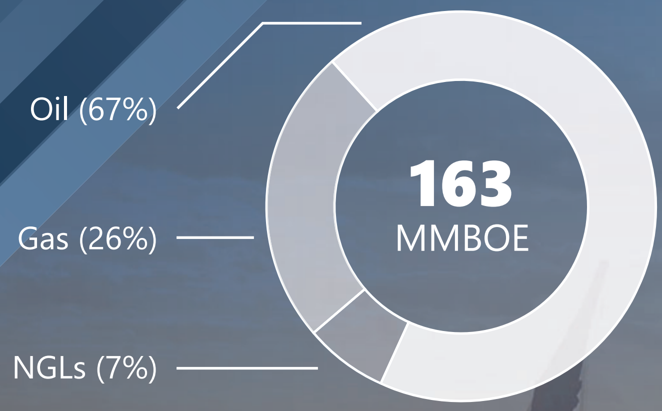
NYSE: TALO

All reserves figures as of year end 2020 at SEC prices of $39.47/bbl WTI and $1.97/mcf HH, in perpetuity.

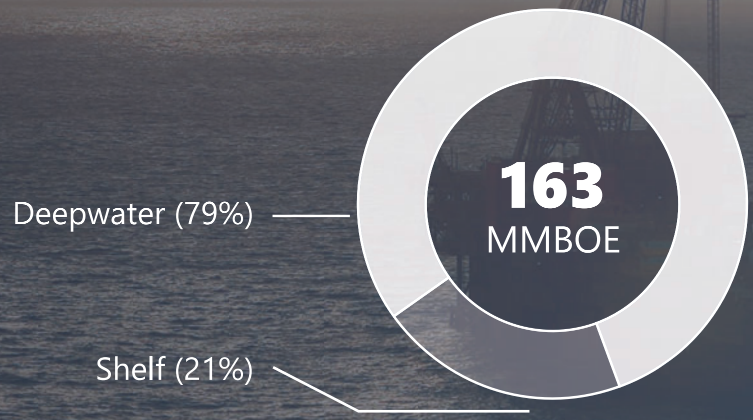
Proved Reserves by Category



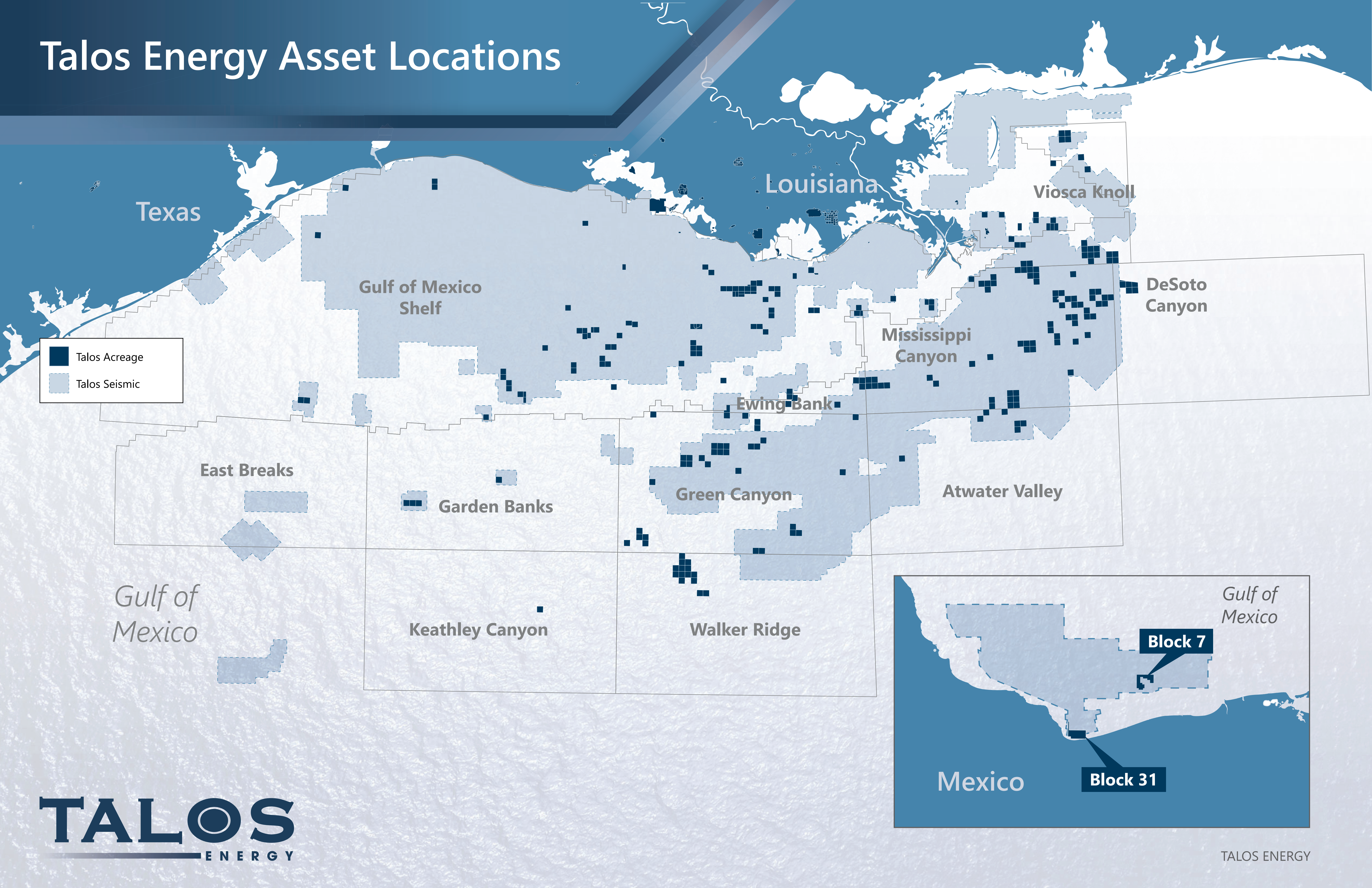
Proved Reserves by Commodity



Proved Reserves by Geography



Talos Energy Asset Locations



Letter to Shareholders

APRIL 2021

This past calendar year was historic in many ways – not only for Talos, our industry or even our country, but for all of us as citizens of a world turned radically and abruptly in a new direction.

The rapid spread of COVID-19 and the international response that followed introduced major changes to even the most basic elements of our daily lives – buying groceries, attending events and even seeing each other in person. Without a doubt, we all faced challenges as we adapted to working and learning from home, to taking additional safety precautions at every turn and to coping with the global health crisis in our own ways.

Talos was no exception. 2020 brought about significant adversity on multiple fronts. To our business, the COVID-19 response triggered not only unprecedented commodity demand destruction, but also required us to rethink every element of our operations in the field and in our offices and to find new ways to work across the supply chain. At this time one year ago, we were experiencing the health crisis live, but could not have anticipated the impact it would ultimately have. Additionally, we knew at this time one year ago that the actions of OPEC+ would drive more supply into the market, likely impacting commodity prices to the negative. We could not have anticipated, however, the cascading of oil prices into negative territory for the first time in history. Finally, at this time one year ago we could not have anticipated what became one of the busiest storm seasons in our basin in over a decade, causing significant production interruptions over many months of the year. These factors together presented one of the most challenging situations we have ever experienced.

> "I'm proud to say that our company withstood this adversity and is stronger now than we were a year ago."

One year later, I'm proud to say that our company withstood this adversity and is stronger now than we were a year ago. The test of the past 12 months validated that our core skill set is unique, that our strategy is solid and that Talos has the speed, flexibility and wherewithal to withstand future challenges.

We exited the year with a larger reserves base, lower operating and capital costs than the year before and both production and liquidity at similar pre-pandemic levels. This resiliency is a reflection of our culture and the quality of our team from the ground up.

Our Response

As the days and weeks of early 2020 developed, it became increasingly clear a crisis situation was unfolding, and a swift and impactful response would be required. The Talos management team had successfully navigated three commodity crises in the past and successfully defended shareholder value in each case. From those experiences we know first-hand that basic financial and operational principles are often the key to survival, which is why we've always strived to maintain low leverage and high liquidity, adequately hedge commodity prices and preserve optionality in our capital planning.

On the operational front, we made numerous changes to streamline production and drilling activities and to reduce costs wherever possible, which supported margins despite commodity price declines. We also selectively deferred production and optimized our maintenance schedule for the year to adapt to the rapidly changing markets.

(Continued on Page 3)

Talos is a leader in offshore energy exploration and production. We are one of the largest independent producers in the U.S. Gulf of Mexico and offshore Mexico, with an asset portfolio that is oil-weighted, highly operated and primarily located in prolific deepwater regions.

We significantly reduced our capital program for the year, trimming longer-cycle and higher-risk projects in favor of development and exploitation projects around our infrastructure that bolstered reserves and cash flow almost immediately. This revised capital planning focus was key to maintaining the solid fundamental value that underpinned our liquidity, providing us the financial flexibility to weather the worst months of the year. By year-end 2020, even after taking into account a significant decline in SEC benchmark oil prices, we grew proved reserves by over 15% and grew proved developed producing reserves by over 30%, demonstrating the focus on conversion of lower-risk non-producing reserves to producing volumes.

Our Accomplishments

Beyond the challenges of the year, we had numerous accomplishments that would be significant in any environment. In combination with our rapid response to the crisis with operational improvements and cost reductions, these achievements have placed Talos on strong footing as we enter 2021.

Among our many projects for the year, the Tornado water flood success is worth noting for several reasons. The project sources an existing, natural aquifer directly above the Tornado reservoir and is the first project of its kind in deepwater. We believe the project will not only support the incremental recovery of 25-35 million barrels of oil equivalent, but was also highly cost-effective to implement and quick to generate results. We also executed on a redevelopment program around our Green Canyon 18 facility, bringing online the Kaleidoscope project by year end and continuing our success in early 2021 with the Tokum project. These wells leverage our facility ownership to provide high-margin production with quick turnaround times. We look forward to executing a similar program in the coming year from our Pompano facility, its first major redevelopment since the Stone merger in 2018.

We maintained constant focus on our balance sheet throughout the year, and capped the year with our first series of capital markets transactions as a public company. In total, we raised approximately $675 million of gross proceeds that increased liquidity and, most importantly, eliminated a near-term debt maturity in 2022. During this process we added flexibility for future M&A financing as well as project financing for our world-class Zama development in offshore Mexico.

Finally, we upheld our outstanding safety track record and advanced our emissions reduction initiatives. We completed the year with just one recordable incident among Talos employees and totaled less than ¾ of one barrel of hydrocarbons released from over 24 million barrels equivalent produced or managed. These are highly competitive results not only in our basin and our industry, but across most sectors of the broader economy. We recorded an 11% reduction in greenhouse gas (GHG) intensity as compared to the year before, and we expect to continue this trend moving forward.

> "We're proud of the role that we play in satisfying the demand, recognized and often unrecognized, for our products that is present every day."

In 2020, we also expanded and formalized our environmental, safety and governance (ESG) efforts, starting with the publication of our first-ever ESG report. Following that report, we have organized employee-led committees focusing on a range of topics including emissions reduction, safety, community relations, carbon capture technology and potential offshore renewable investments, among others. These self-organized, internal groups are charting our course for continued progress in many categories. We look forward to discussing our progress later this year as we continue our ESG evolution with the release of our second annual report.

(Continued on Page 5)


HOOVER FERGUSON
iBC

Reminder of Our Impact

As a society, we experienced first-hand over the past several months the diverse and critical needs that oil and gas serve in our modern world. While traditional demand for gasoline and jet fuel suffered, we utilized technology such as tablets and laptops made possible by hydrocarbons more than ever to work and educate. We relied on logistics providers to satisfy changing consumer patterns and deliver products right to our doorsteps. We used plastics to protect ourselves and others. And, we continued to heat and cool our homes through tough summer and winter conditions.

Unfortunately, 2020 also brought about increased political rhetoric, which often disregards the critical role our industry plays in modern life and, most relevant to Talos, aimed specifically to curb operations on federal lands. As the largest federal producing province, the Gulf of Mexico is not only an important national resource from the perspective of providing secure, affordable supply, but also for its nationwide economic and jobs impact and for its global leadership in technology, safety, emissions and business ethics relative to other sources.

As a leading independent energy producer, we're proud of the role that we play in satisfying the demand, recognized and often unrecognized, for our products that is present every day. However, we're equally proud to supply that demand in a manner that prioritizes safety and environmental responsibility, that supports our local communities and that optimizes our rich domestic resources to promote economic and environmental justice.

Talos in 2021 and Beyond

In closing, I'm proud of all that we accomplished in 2020 and how we responded to significant adversity. One year after the onset of the crisis, I believe we're a stronger, better positioned company than we were at the start.

TIMOTHY DUNCAN
TALOS ENERGY CEO

In 2021, I look forward to advancing several potential near-term catalysts for the company, including high-impact exploration projects as well as progressing our Zama asset towards FID by the end of the year. We will continue to look for organic and inorganic ways to increase value for our shareholders. From developing our diverse project portfolio to executing tactical and strategic acquisition activities, we expect 2021 to be a highly active year.

I'd like to thank every employee, shareholder and stakeholder for their support, in whichever way it came, throughout 2020. We cannot control global macroeconomic events and conditions, but we can continue to manage our business to protect and grow long-term value, which has always remained our goal through the rapidly changing conditions of the past year and will remain our goal in the future.

Sincerely Yours,

Timothy S. Duncan
President and Chief Executive Officer

Corporate Responsibility

COMMITMENT TO SAFE, RESPONSIBLE ENERGY PRODUCTION

Talos is committed to maximizing the health and safety of its employees, contractors and external stakeholders while also maintaining a constant focus on environmentally responsible and socially conscious operations.

Health, safety, the environment and sustainability are at the core of our operational culture. We constantly strive to create an engaged and empowered workforce to promote a safety-first culture in all stages of our business.

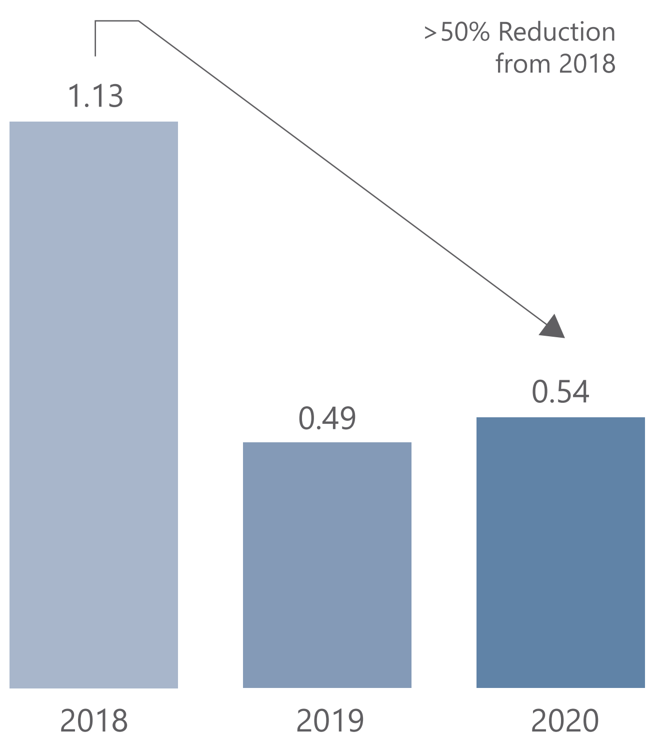
Safety is a top priority in our highly technical and complex operating environment, which is among the most challenging in the industry. We manage our organization at all levels to focus on safety, including granting and promoting Stop Work Authority to every single employee and contractor.

We focus on continuous improvement, training and operate in strict compliance with rigorous federal and state regulations. In 2020, we maintained our Total Recordable Incident Rate (TRIR) below the average for Gulf of Mexico operators and sustained significant improvements made since 2018.

Environmental responsibility is also critically important to Talos. Last year, we continued our trend of reductions in both total air emissions and greenhouse gas intensity while recording zero hydrocarbon spills in excess of a single barrel.

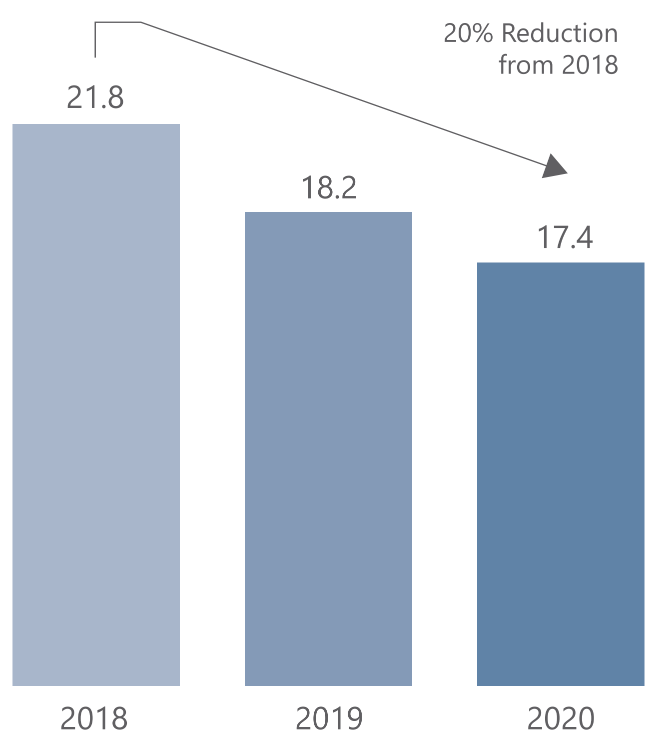
TRIR

(Incident Rate)



GHG INTENSITY

(Gross Operated Production[1], MT CO_2 Equivalent/Mboe)



(1) GHG intensity based upon Talos operated production plus third-party operated wells flowing through Talos production facilities.

Culture and Community

SUPPORTING OUR EMPLOYEES AND LOCAL COMMUNITIES

Talos aims to be a highly supportive partner of our employees, their careers, their families and the broader communities in which they work and live. We actively support numerous organizations and are consistently named one of the Top Workplaces in Houston by the Houston Chronicle.

We provide highly competitive benefits, flexible schedules and are committed to diversity, inclusion and equitable treatment for all staff. We also maintain a clear commitment to the highest ethical standards, anti-corruption and employee and vendor conduct. We offer regular training and career development. In 2020, we launched a tuition reimbursement program for employees to support their higher education at accredited institutions.

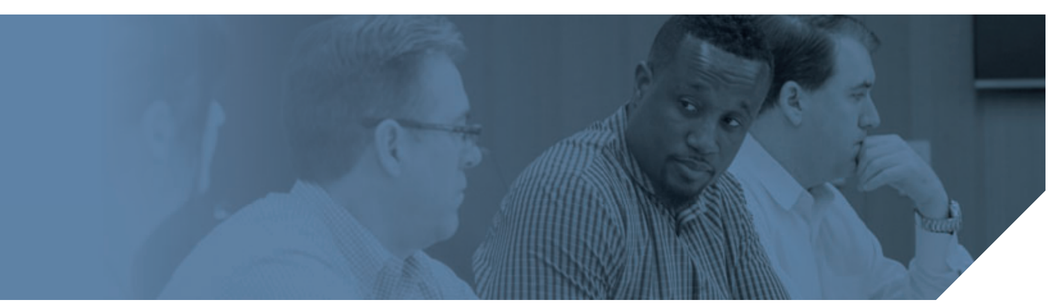
In our communities, we actively support numerous organizations through volunteering and charitable giving. Since 2019, we've committed and raised over $1.2 million and offer $500 every year to every employee to donate to an organization of their choice.

~$1.2M

Committed or raised for local communities and charitable organizations since 2019

$500

Offered annually to every employee to donate to an organization of their choice



8 Years

In a row that Talos has been recognized as a Top Workplace by the Houston Chronicle

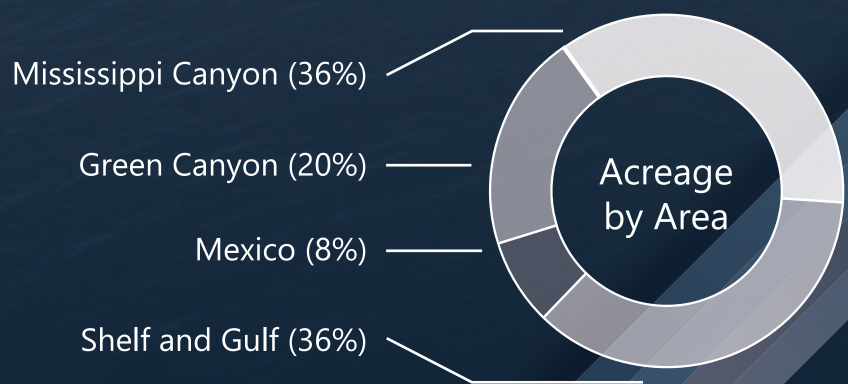
Poised for the Future

KEY GROWTH CATALYSTS

Access to major catalysts is a unique differentiator for Talos and provides the potential for exceptional long-term value creation. The company holds one of the largest acreage positions in the Gulf, maintains a strategic footprint across all exploration geologies in the basin, and aims to FID its world-class Zama project in offshore Mexico by year-end of 2021.

Advantaged Footprint in the Gulf

1.5MM
GROSS ACRES



Trend	Prospects	Acreage	Facilities	Partnerships
Cretaceous	✓	✓	✓	
Miocene	✓	✓	✓	✓
Norphlet	✓	✓	✓	✓
Wilcox	✓	✓		✓
Other	✓	✓	✓	✓

Zama Discovery

Talos was one of the first private companies to enter Mexico after historic reforms opened the country to outside investment.

In 2017, Talos announced its Zama discovery, one of the largest shallow water oil discoveries globally in multiple decades and which was subsequently named the Global Discovery of the Year by Wood Mackenzie.

Since discovery, Talos has rapidly and safely completed a full appraisal program to delineate the resource. Following expected unitization in 2021, Talos aims to reach Final Investment Decision on the project by year-end 2021, starting the process to develop and bring online this tremendous resource.

2020 Financial Highlights

2017-2020 FISCAL YEARS

Year Ended (Millions)	2020	2019	2018	2017
Revenue	$587.5	$927.6	$891.3	$412.8
Net Income (Loss)	(465.6)	58.7	221.5	(62.9)
Capital Expenditures	405.5	545.7	390.6	227.2
Total Long-term Debt(1)	$1,055.3	$826.5	$766.2	$808.6

Reserves(2) (MMBoe)				
Proved Developed Producing (PDP)	89.7	68.3	78.1	31.8
Proved Developed Non-Producing (PDNP)	37.4	29.6	37.5	21.9
Proved Developed	127.1	97.9	115.5	53.7
Proved Undeveloped (PUD)	35.9	43.8	36.2	46.9
Total Proved	**163.0**	**141.7**	**151.7**	**100.6**

Production				
Sales volume (MMBoe)	20.0	19.0	16.7	10.5
Average daily production (MBoe/d)	54.7	52.0	45.9	28.7

(1) Includes finance lease and excludes original issue discounts and deferred financing costs.

(2) All reserves figures at year-end SEC prices of $39.47/bbl WTI and $1.97/mcf HH, $61.01/$2.59, $69.42/$3.08, $51.36/$3.20 for 2020, 2019, 2018 and 2017, respectively.

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2020

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 001-38497

Talos Energy Inc.
(Exact name of Registrant as specified in its Charter)

Delaware **(State or other jurisdiction of incorporation or organization)**	**82-3532642** **(I.R.S. Employer Identification No.)**
333 Clay Street, Suite 3300 **Houston, TX** **(Address of principal executive offices)**	**77002** **(Zip Code)**

Registrant's telephone number, including area code: (713) 328-3000

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	TALO	NYSE

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

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 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, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

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

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

Indicate by check mark whether the registrant 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 Act). YES ☐ NO ☑

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant, based on the closing price of the shares of common stock on the New York Stock Exchange on June 30, 2020, was $213,227,480.

The number of shares of registrant's Common Stock outstanding as of March 3, 2021 was 81,279,989.

Portions of the registrant's definitive proxy statement relating to the 2021 Annual Meeting of Shareholders are incorporated by reference into Part III of this report.

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GLOSSARY

The following are abbreviations and definitions of certain terms used in this document, which are commonly used in the oil and natural gas industry:

***Barrel or Bbl* —** One stock tank barrel, or 42 United States gallons liquid volume.

***Boe* —** One barrel of oil equivalent determined using the ratio of six Mcf of natural gas to one barrel of crude oil or condensate.

***Boepd* —** Barrels of oil equivalent per day.

***Btu* —** British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water one degree Fahrenheit.

***Completion* —** The installation of permanent equipment for the production of oil or natural gas.

***Deepwater* —** Water depths of more than 600 feet.

***Developed acres* —** The number of acres that are allocated or assignable to producing wells or wells capable of production.

***Field* —** An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition.

***Gross acres or gross wells* —** The total acres or wells in which the Company owns a working interest.

***MBbls* —** One thousand barrels of crude oil or other liquid hydrocarbons.

***MBblpd* —** One thousand barrels of crude oil or other liquid hydrocarbons per day.

***MBoe* —** One thousand barrels of oil equivalent.

***MBoepd* —** One thousand barrels of oil equivalent per day.

***Mcf* —** One thousand cubic feet of natural gas.

***Mcfpd* —** One thousand cubic feet of natural gas per day.

***MMBoe* —** One million barrels of oil equivalent.

***MMBtu* —** One million British thermal units.

***MMcf* —** One million cubic feet of natural gas.

***MMcfpd* —** One million cubic feet of natural gas per day.

***Net acres or net wells* —** The sum of the fractional working interests the Company owns in gross acres or gross wells.

***NGL* —** Natural gas liquid. Hydrocarbons which can be extracted from wet natural gas and become liquid under various combinations of increasing pressure and lower temperature. NGLs consist primarily of ethane, propane, butane and natural gasoline.

***NYMEX* —** The New York Mercantile Exchange.

***NYMEX Henry Hub* —** Henry Hub is the major exchange for pricing natural gas futures on the New York Mercantile Exchange. It is frequently referred to as the Henry Hub Index.

***Productive well* —** A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

***Proved developed reserves* —** In general, proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods. The SEC provides a complete definition of developed oil and gas reserves in Rule 4-10(a)(6) of Regulation S-X.

Proved reserves — Proved reserves are 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.

Proved undeveloped reserves — In general, proved 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. The SEC provides a complete definition of undeveloped oil and gas reserves in Rule 4-10(a)(31) of Regulation S-X.

PV-10 — The present value of estimated future revenues, discounted at 10% annually, to be generated from the production of proved reserves determined in accordance with SEC guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to (i) non-property related expenses such as general and administrative expenses, derivatives, debt service and future income tax expense or (ii) depreciation depletion and amortization expense.

SEC — The Securities and Exchange Commission.

SEC pricing — The unweighted average first-day-of-the-month commodity price for crude oil or natural gas for the period beginning January 1, 2020 and ending December 1, 2020, adjusted by lease for market differentials (quality, transportation, fees, energy content, and regional price differentials). The SEC provides a complete definition of prices in "*Modernization of Oil and Gas Reporting*" (Final Rule, Release Nos. 33-8995; 34-59192).

Shelf — Water depths up to 600 feet.

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. For the years ending December 31, 2020, 2019 and 2018 we were subject to U.S. federal and state income taxes at the entity level.

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 gas regardless of whether such acreage contains proved reserves.

Working interest — The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

WTI or West Texas Intermediate — A light crude oil produced in the United States with an American Petroleum Institute ("API") gravity of approximately 38-40 and the sulfur content is approximately 0.3%.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

The information in this report includes “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended (the “Securities Act”), and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). All statements, other than statements of historical fact included in this report, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this report, the words “could,” “believe,” “anticipate,” “intend,” “estimate,” “expect,” “project,” “forecast,” “may,” “objective,” “plan,” and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on our current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events. These forward-looking statements are based on management’s current belief, based on currently available information, as to the outcome and timing of future events. Forward-looking statements may include statements about:

- business strategy;
- reserves;
- exploration and development drilling prospects, inventories, projects and programs;
- our ability to replace the reserves that we produce through drilling and property acquisitions;
- financial strategy, liquidity and capital required for our development program and other capital expenditures;
- realized oil and natural gas prices;
- timing and amount of future production of oil, natural gas and NGLs;
- our hedging strategy and results;
- future drilling plans;
- availability of pipeline connections on economic terms;
- competition, government regulations and political developments;
- our ability to obtain permits and governmental approvals;
- pending legal, governmental or environmental matters;
- our marketing of oil, natural gas and NGLs;
- leasehold or business acquisitions on desired terms;
- costs of developing properties;
- general economic conditions;
- credit markets;
- impact of new accounting pronouncements on earnings in future periods;
- estimates of future income taxes;
- our estimates and forecasts of the timing, number, profitability and other results of wells we expect to drill and other exploration activities;
- uncertainty regarding our future operating results and our future revenues and expenses; and
- plans, objectives, expectations and intentions contained in this report that are not historical.

We caution you that these forward-looking statements are subject to numerous risks and uncertainties, most of which are difficult to predict and many of which are beyond our control. These risks include, but are not limited to, commodity price volatility due to the continued impact of the coronavirus disease 2019 ("COVID-19") and governmental measures related thereto on global demand for oil and natural gas and on the operations of our business; the ability or willingness of the Organization of Petroleum Exporting Countries ("OPEC") and non-OPEC countries, such as Saudi Arabia and Russia, to set and maintain oil production levels; the impact of any such actions; lack of transportation and storage capacity as a result of oversupply, government and regulations; lack of availability of drilling and production equipment and services; adverse weather events, including tropical storms, hurricanes and winter storms; inflation; environmental risks; failure to find, acquire or gain access to other discoveries and prospects or to successfully develop and produce from our current discoveries and prospects; geologic risk; drilling and other operating risks; well control risk; regulatory changes; the uncertainty inherent in estimating reserves and in projecting future rates of production; cash flow and access to capital; the timing of development expenditures; potential adverse reactions or competitive responses to our acquisitions and other transactions; the possibility that the anticipated benefits of our business combination are not realized when expected or at all, including as a result of the impact of, or problems arising from, the integration of acquired assets and operations, and the other risks discussed in Part I, Item 1A. Risk Factors which are included herein.

Reserve engineering is a process of estimating underground accumulations of oil, natural gas and NGLs that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reserve engineers. In addition, the results of drilling, testing and production activities may justify upward or downward revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of oil, natural gas and NGLs that are ultimately recovered.

Should one or more of the risks or uncertainties described herein occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. All forward-looking statements, expressed or implied, included in this report are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue. Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances after the date of this report.

SUMMARY RISK FACTORS

Risks Related to our Business and the Oil and Natural Gas Industry

- Oil and natural gas prices are volatile. Sustained periods of low, or further declines in, commodity prices may adversely affect our financial condition and results of operations, cash flows, access to the capital markets and ability to grow.
- Our production, revenue and cash flow from operating activities are derived from assets that are concentrated in a single geographic area, making us vulnerable to risks associated with operating in one geographic area.
- Production periods or reserve lives for U.S. Gulf of Mexico properties may subject us to higher reserve replacement needs and may impair our ability to reduce production during periods of low oil and natural gas prices.
- Our actual recovery of reserves may substantially differ from our proved reserve estimates.
- Our acreage has to be drilled before lease expirations in order to hold the acreage by production. If commodity prices become depressed for an extended period of time, it might not be economical for us to drill sufficient wells in order to hold acreage, which could result in the expiry of a portion of our acreage, which could have an adverse effect on our business.
- The marketability of our production depends mostly upon the availability, proximity and capacity of oil and natural gas gathering systems, pipelines and processing facilities.
- Lower oil and natural gas prices and other factors in the future may result in ceiling test write-downs and other impairments of our asset carrying values.
- If we are forced to shut-in production, we will likely incur greater costs to bring the associated production back online, and will be unable to predict the production levels of such wells once brought back online.
- Our business could be negatively affected by security threats, including cybersecurity threats, terrorist attacks and other disruptions.
- Events outside of our control, including an epidemic or outbreak of an infectious disease, such as COVID-19, may materially adversely affect our business.
- We may not receive payment for a portion of our future production.
- New technologies may cause our current exploration and drilling methods to become obsolete, and we may not be able to keep pace with technological developments in our industry.
- We may not be in a position to control the timing of development efforts, the associated costs or the rate of production of the reserves from our non-operated properties.
- Hedging transactions may limit our potential gains.
- Our operations may incur substantial liabilities to comply with environmental laws and regulations as well as legal requirements applicable to marine mammals and endangered and threatened species.
- We may be unable to provide the financial assurances in the amounts and under the time periods required by the BOEM if it submits future demands to cover our decommissioning obligations. If in the future the BOEM issues orders to provide additional financial assurances and we fail to comply with such future orders, the BOEM could elect to take actions that would materially adversely impact our operations and our properties, including commencing proceedings to suspend our operations or cancel our federal offshore leases.
- Our oil and gas operations are subject to various international, foreign and U.S. federal, state and local governmental regulations that materially affect our operations.
- Our operations may be adversely affected by political and economic circumstances in the countries in which we operate.
- We may experience significant shut-ins and losses of production due to the effects of hurricanes in the U.S. Gulf of Mexico and in the shallow waters off the coast of Mexico.

Risks Related to our Capital Structure and Ownership of our Common Stock

- Our debt level and the covenants in our current or future agreements governing our debt, including our Bank Credit Facility and the indenture for our 11.00% Second-Priority Senior Secured Notes, could negatively impact our financial condition, results of operations and business prospects. Our failure to comply with these covenants could result in the acceleration of our outstanding indebtedness.
- A financial crisis may impact our business and financial condition and may adversely impact our ability to obtain funding under our Bank Credit Facility or in the capital markets.
- We require substantial capital expenditures to conduct our operations and replace our production, and we may be unable to obtain needed financing on satisfactory terms necessary to fund our planned capital expenditures.
- We are a holding company that has no material assets other than our ownership of the equity interests of Talos Production Inc. Accordingly, we are dependent upon distributions from Talos Production Inc. to pay taxes, cover our corporate and other overhead expenses and pay dividends, if any, on our common stock.
- Our estimates of future asset retirement obligations may vary significantly from period to period and unanticipated decommissioning costs could materially adversely affect our future financial position and results of operations.
- We may not realize all of the anticipated benefits from our future acquisitions, and we may be unable to successfully integrate future acquisitions.
- Our future acquisitions could expose us to potentially significant liabilities, including P&A liabilities.
- Resolution of litigation could materially affect our financial position and results of operations.
- We are controlled by Apollo Funds and Riverstone Funds. The interests of Apollo Funds and Riverstone Funds may differ from the interests of our other stockholders.

PART I

Items 1 and 2. Business and Properties

Overview

As used in this Annual Report on Form 10-K (this "Annual Report") and unless otherwise indicated or the context otherwise requires, references to "we," "us," "our," "Talos Energy Inc.," "Talos" and the "Company" refer to, from and after the Stone Closing (as defined below), Talos Energy Inc. and its consolidated subsidiaries and prior to the Stone Closing, Talos Energy LLC and its consolidated subsidiaries.

We were incorporated on November 14, 2017 under the laws of the state of Delaware for the purpose of effecting the business combination between Talos Energy LLC and Stone Energy Corporation ("Stone"), pursuant to which each of Talos Energy LLC and Stone became our wholly-owned subsidiary. We refer to this business combination as the "Stone Combination," and its date of consummation, May 10, 2018, as the "Stone Closing Date."

We are a technically-driven independent offshore energy company engaged in oil and gas exploration and production in the U.S. Gulf of Mexico and offshore Mexico. We are focused on safely and efficiently maximizing value through our operations. We leverage decades of geology, geophysics and offshore operations expertise towards the acquisition, exploration, exploitation and development of assets in key geological trends that are present in many offshore basins around the world.

We combine our technical experience in geology, geophysics and engineering with innovative resource evaluation techniques and seismic imaging expertise to discover new resources. We rely on our operational experience to safely and responsibly optimize production and recovery from our assets. Finally, we leverage our commercial and corporate management experience to most effectively allocate our capital to balance risk and reward, grow our business and maximize long-term shareholder value.

Prior to the Stone Combination, Talos Energy Inc. had not conducted any material activities other than those incident to its incorporation and certain matters contemplated by that certain transaction agreement, dated as of November 21, 2017 (the "Stone Transaction Agreement") by and among Stone, Talos Energy Inc., Sailfish Merger Sub Corporation ("Merger Sub"), Talos Energy LLC (which was renamed to Talos Energy Inc. and converted into a Delaware corporation after the Stone Combination) and Talos Production LLC (which was converted into a Delaware corporation named Talos Production Inc. in 2019), pursuant to which, among other items, each of Stone, Talos Production LLC and Talos Energy LLC became wholly-owned subsidiaries of Talos Energy Inc. The Stone Combination was accounted for as a business combination in accordance with accounting principles generally accepted in the United States of America ("GAAP"), with Talos Energy LLC treated as the "acquirer" and Stone treated as the "acquired" company for financial reporting purposes. Accordingly, the reported financial condition and results of operations of the Company reflect the assets, liabilities and results of operations of Talos Energy LLC (as our predecessor) prior to the Stone Combination, and do not reflect the assets, liabilities and results of operations of Stone prior to such date. The assets, liabilities and results of operations of Talos Energy LLC have not been, and will not be, restated retrospectively to reflect the historical financial position or results of operations of Stone.

For more information on Talos Energy LLC, our predecessor for financial reporting purposes, see Part IV, Item 15. Exhibits, Financial Statement Schedules — Note 1 — *Formation and Basis of Presentation.*

Business Strategy

We intend to increase stockholder value by growing our reserves, production, cash flow and future growth opportunities in a capital efficient manner. Our core competencies of deep technical expertise and extensive offshore operating experience allow us to successfully manage our asset base and consistently make attractive investments, thereby increasing shareholder value over time.

We maintain a large and diverse in-house technical staff focused on geology, geophysics, engineering and other technical disciplines, providing many decades of exploration and production experience in key resource trends where we focus. Our significant library of seismic data resources, which focuses on the U.S. Gulf of Mexico and offshore Mexico, allows our technical team to apply proprietary seismic reprocessing techniques to evaluate or re-evaluate potential resources across our asset portfolio. Finally, we have deep in-house experience across our offshore operations, production operations, safety, facilities and business development.

Our strategic business development activities allow us to consistently identify and evaluate new opportunities through a wide range of potential avenues, including government lease sales, joint ventures and acquisitions, among others. Our proven track record through the drill bit frequently attracts potential drilling partners in projects that we operate, while in non-operated projects we leverage our core competencies to independently identify the best investment opportunities, review partner-proposed projects and be a value-added contributor. Finally, our asset acquisition strategy is focused on assets with a geological setting that can benefit from our ability to use our seismic database and technical expertise to re-evaluate and improve the acquired properties. Specifically, our acquisition focus areas target a variety of potential situations and sellers that are currently available in offshore basins, including single asset acquisitions, consolidation of private companies and broader asset package transactions. We seek to actively participate in government lease sales to identify and acquire attractive leasehold acreage, which in many cases has not been evaluated with the latest reprocessed seismic data, resulting in an opportunity for us to identify previously unknown drilling prospects.

We have historically focused our operations in the U.S. Gulf of Mexico because of our deep experience and technical expertise in the basin, which maintains favorable geologic and economic conditions, including multiple reservoir formations, comprehensive geologic and geophysical databases, extensive infrastructure and an attractive and asset acquisition market. Utilizing our core competencies in conjunction with a robust and active business development effort allows us to use the following strategies to increase stockholder value:

Continuously Optimizing our Attractive Existing Asset Base.

We benefit from our proven ability to enhance and extend the life of existing projects within our portfolio. Investments in optimization projects across our asset base aim to stabilize and improve the profile of producing assets by increasing recovery, production and cash flow with typically relatively low investment capital and risk. These projects allow for reinvestment opportunities in exploitation and exploration projects.

Conducting Development and Near-Field Projects In and Around Our Existing Asset Footprint.

We undertake asset development and exploitation drilling projects in close proximity to our existing assets as well as facilities that we either own or have access to. These projects leverage ongoing operations and existing technical knowledge of the area, often coupled with recent proprietary seismic reprocessing evaluations to provide attractive incremental investment opportunities to grow reserves, production and cash flow in well-understood areas.

Our asset footprint, which includes operational control of several key shallow and deepwater facilities, allows us to invest in a diverse set of opportunities ranging from in-field development to high impact exploration projects while optimizing our facilities to lower incremental operating costs structures. We also believe our operated infrastructure can be attractive to other operators looking for a host facility for their subsea tie-back projects, which allows us either to be involved in new investment opportunities or to offset the operating cost of these facilities with fee-based income earned by hosted third-party production.

Engaging in Exploration Activities to Grow Asset Base and Potentially Unlock Significant New Resources.

We conduct exploration drilling activities across our acreage set with risk-weighted investments that could establish significant new reserves and production. These projects are intended to optimize risk and reward across our portfolio of prospective drilling opportunities by finding and developing previously undiscovered resources along existing or emerging geological trends with the most efficient deployment of capital. When successful, exploration drilling activities can organically generate material new assets for the Company.

Utilize Acquisitions and Other Business Development Activities to Expand Asset Base, Opportunity Set and Value Creation Potential.

We rely on our commercial and business development activities to expand our asset base through the acquisition or optimization of additional or existing properties, respectively. Commercial and business development provides a key avenue to create additional value from the acquisition of undervalued properties where we can apply our technical and operational competencies to generate upside. Additionally, we utilize business development to acquire new leaseholds, enter new projects and increase or decrease working interests in various existing projects to optimize capital planning and our targeted risk/return profile for varying business conditions. Consolidation opportunities in our basin and, more broadly, in the offshore exploration and production segment in other basins around the world, are numerous and span a wide range of lifecycle stages, sizes and geographic variables. We expect to continue utilizing acquisitions and business development to grow our business in a manner that preserves a strong and healthy credit profile as well as a diverse and high-quality asset base.

Maintain Safety, Environmental Responsibility and Sustainability as Key Principles for Operations Across All Areas of our Business.

We are focused on maintaining high standards of safety, environmental responsibility and corporate citizenship across all elements of our business. We closely monitor safety performance and consistently take steps to improve our performance. For the year ended 2020, we were able to maintain a high level of safety performance with a lower recordable incident rate when compared to the average for offshore operators in the U.S. Gulf of Mexico and as well as across numerous other industrial sectors of the broader economy. We strive to execute our business plan while simultaneously minimizing our environmental footprint, including emissions, potential spills and other impacts. Due to the nature of subsea wells and ample offshore pipelines, we believe the offshore operating environment is a region where greenhouse gas ("GHG") emissions can continue to be lowered over time. Finally, we aim to be a good corporate citizen in the regions and communities where we operate. We recently published our inaugural Environmental Social and Governance ("ESG") report highlighting our performance and initiatives across all of these categories and other topics.

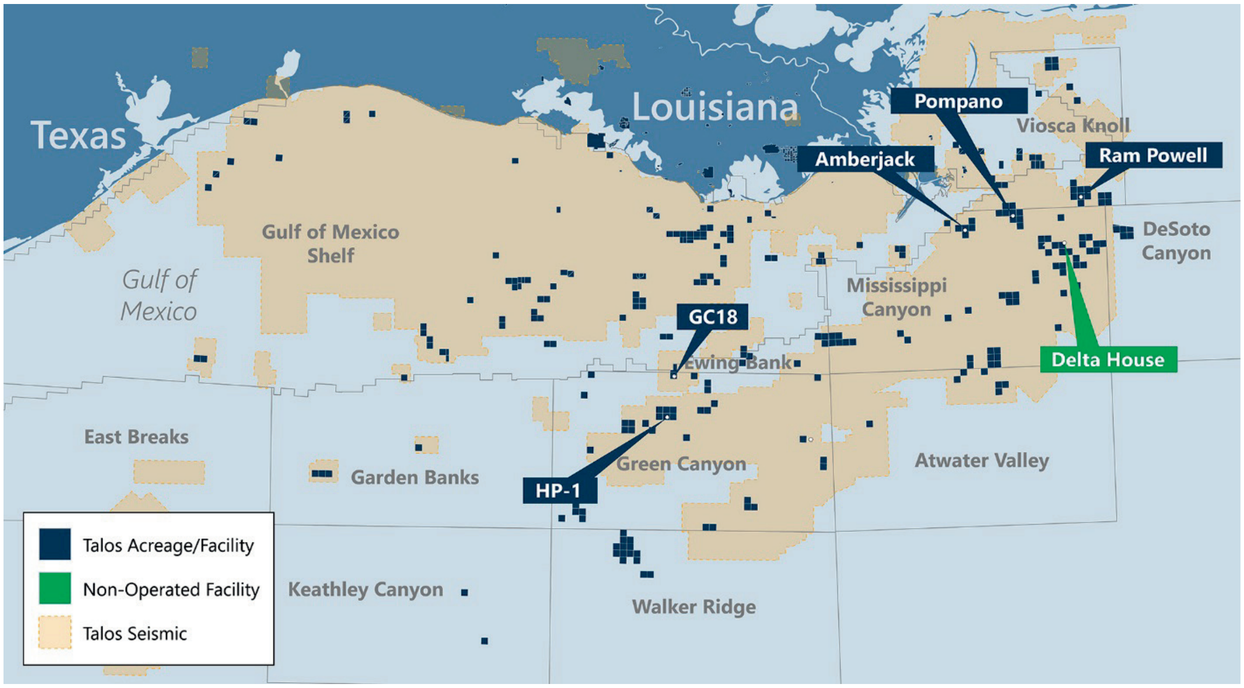
Properties

United States Gulf of Mexico

Our area of focus in the United States is the Gulf of Mexico deepwater, which is generally considered to comprise water depths over 600 feet. Our strategy is focused in areas characterized by clearly defined infrastructure, well-known production history and geological well control, which reduces operational and investment risk. We believe the potential for large discoveries and increasing success rates in the sub-salt and mini-basin lower Pliocene and Miocene plays has resulted in increased industry focus on this area over the last decade.

We believe our deepwater operations in the U.S. Gulf of Mexico provide significant potential growth opportunities through our planned drilling program. Through our technical approach of starting with known hydrocarbon systems and applying modern seismic reprocessing techniques, we have generated a substantial inventory of deepwater prospects that we believe are capable of delivering predictable production growth. We primarily focus our exploitation and exploration efforts around our existing infrastructure. This subsea tie-back strategy allows for better project economics and shorter periods between a discovery and production.

As of December 31, 2020, our core areas in the United States are illustrated below:



The following table sets forth a summary of certain key 2020 information regarding our core areas in the United States:

	Estimated Proved Reserves						
	MBoe	% Oil	% Natural Gas	% NGLs	% Proved Developed	Net Production (MBoe)	% Operated
United States Core Areas							
Green Canyon	56,555	82%	12%	6%	58%	5,630	96%
Mississippi Canyon	72,535	73%	18%	9%	90%	8,549	56%
Shelf & Gulf Coast	33,943	30%	68%	2%	87%	5,820	61%
Total United States	163,033	67%	26%	7%	78%	19,999	

Green Canyon — Green Canyon is a deepwater region in the Central U.S. Gulf of Mexico and is a key focus area both industry-wide and for our exploration activities. We operate two production facilities in the region, including a floating production unit, the Helix Producer I ("HP-I").

Mississippi Canyon — Mississippi Canyon is a deepwater region in the eastern portion of the Central U.S Gulf of Mexico with a track record of prolific production and ongoing exploration success that continues to unlock new resources. We operate three production facilities in the region and are active as both an operator and non-operating partner in numerous development projects and producing fields.

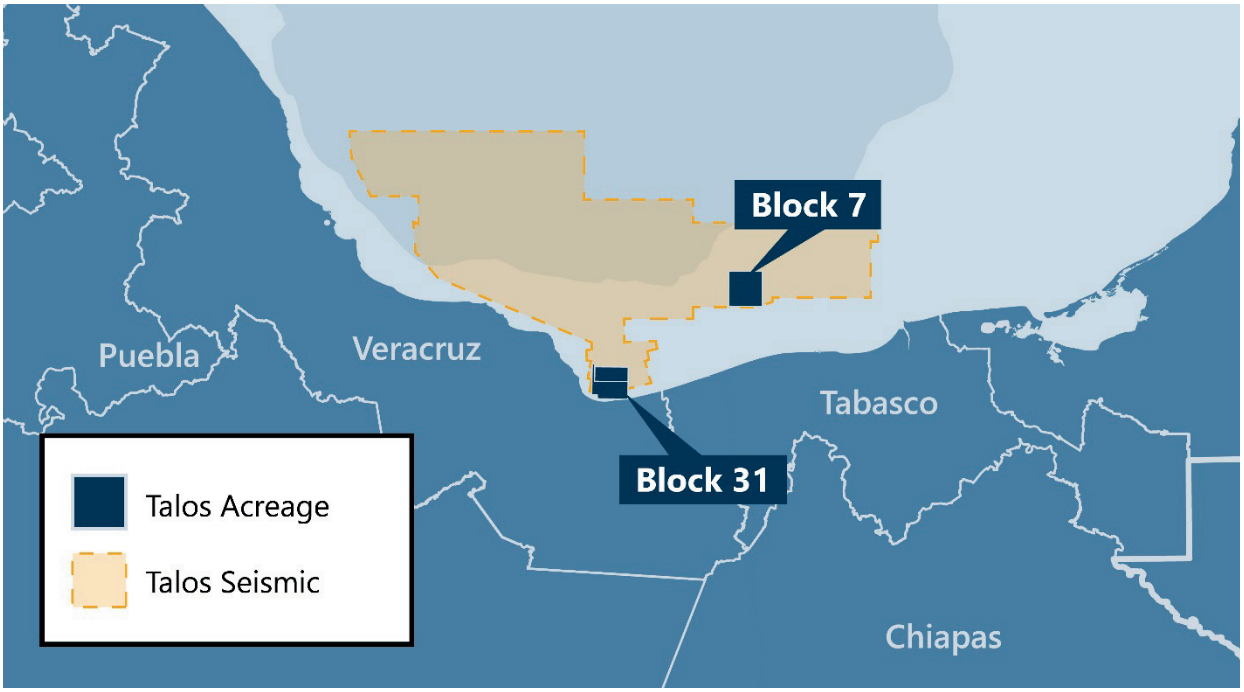
Shelf and Gulf Coast — The U.S. Gulf of Mexico Shelf (the "Shelf") and Gulf Coast ("Gulf Coast") area spans an enormous geographical area across the basin and provides diverse production from numerous operated production facilities. The Shelf area is a producing region of the basin with attractive redevelopment, recovery enhancement and exploration opportunities.

Mexico

Our areas of focus in Mexico are blocks located within the Sureste Basin, a prolific proven hydrocarbon province, in the shallow waters off the coast of Mexico's Veracruz and Tabasco states. We have executed Production Sharing Contracts ("PSCs") with the National Hydrocarbons Commission ("CNH"), Mexico's oil and gas regulator.

The PSCs for our blocks include a cost recovery feature pursuant to which eligible costs in relation to the minimum work program activities are recoverable in-kind at a rate of 125% of costs from future production volumes. Production volumes are allocated in-kind between the consortium and the United Mexican States on a monthly basis based on the contractual value of the hydrocarbons as defined in the PSC. Up to 60% of the monthly contractual value of the hydrocarbons will be allocated to the consortium to recover eligible costs incurred in petroleum activities. Eligible costs exceeding 60% of the current month contractual value of the hydrocarbons will be recoverable in future periods. The amount of royalties will be determined for each type of hydrocarbons (oil, associated natural gas, non-associated natural gas and condensate) using an initial rate, adjusted thereafter for inflation. The remaining value of the hydrocarbons after the allocation for cost recovery and royalties is considered operating profit under the PSC. The allocation of operating profit to the consortium after the allocation for cost recovery and royalties on Blocks 7 and 31 is 31% and 35%, respectively. The profit for oil and gas is determined on a monthly basis using an adjustment mechanism based on the projects rate of return ("ROR"). In the event that the cumulative project's ROR in any one month exceeds 25%, the barrels of oil allocated to the consortium after cost recovery are reduced on a sliding scale. Once the cumulative project's internal ROR meets or exceeds 40%, the reduction locks in at a maximum rate. The Hydrocarbons Revenue Law provides that exploration and extraction activities are zero rated for value-added tax ("VAT") purposes; all other activities are taxed at 16% VAT. The 0% rates only apply to agreements between the United Mexican States and state-owned enterprises or entities, and do not apply to any other agreement executed with third parties, even in the case of exploration and extraction contracts. The Mexico income tax rate is 30%.

As of December 31, 2020, our core areas in Mexico are illustrated below:



Block 7 — In July 2017, we completed drilling operations on the offshore Mexico Zama-1 exploration well. The Zama-1 well is the first offshore exploration well to be drilled in Mexico by the private sector. Well results confirmed the base of the reservoir section, with no penetration of an oil-water contact. The gross oil bearing interval is over 1,100 feet with petrophysical data indicating excellent rock properties and an oil sample with 30 degree API gravity oil. The well has been suspended as a future producer.

In the fourth quarter of 2018, we spud the Zama-2 well, the first appraisal well to be drilled in the field. The Zama-2 well confirmed the results of the original Zama-1 exploration well. In the first quarter of 2019, we drilled the second appraisal penetration, the Zama-2 ST1 well, which successfully tested the northern limits of the reservoir, acquired over 700 feet of whole core to collect detailed rock properties and performed successful well tests in several perforated intervals, reaching an unstimulated and restricted combined production rate of 8.2 MBoepd gross, of which 95% was oil.

In the second quarter of 2019, we concluded our three well appraisal of the Zama discovery. The Zama-3 well was drilled to test the southern extent of the reservoir. Well results included the capturing of approximately 717 feet of whole core.

Front-end engineering & design work is advancing to optimize the recovery and economic development of the field and allow for the earliest possible initial production date. We have significantly narrowed the number of potential development concepts and the prevailing concept design will be the basis for the development. We were also granted a two-year contract term extension as well as regulatory approvals to allow for exploration activities on additional retained acreage in Block 7 that are separate and incremental to the Zama discovery. See Part IV, Item 15. Exhibits, Financial Statement Schedules — Note 4 — *Property, Plant and Equipment* for further detail on our Mexico properties.

In September 2018, we and our consortium partners in Block 7 signed a Pre-Unitization Agreement ("PUA") with Pemex Exploracion y Produccion ("Pemex") related to certain tracts within the Amoca-Yaxche-03 allocation and the contiguous Block 7 PSC. Both areas are situated in the offshore portion of the Sureste Basin. The two year PUA enabled information sharing related to the Zama discovery and potential extension into Pemex's neighboring block. The PUA was approved by the Mexican Secretariat of Energy ("SENER") and on July 7, 2020, we received a notice from SENER instructing the partners of Block 7 and Pemex to unitize the Zama Field. The formal notice established a firm deadline by which the parties should act in good faith to finalize the unit agreement for the Zama Field, which is expected to be signed in 2021. Once the unit agreement is signed, the Zama Field Development Plan, which we are currently preparing, can be submitted to CNH for approval. Our participation interest ("PI") in Block 7 is 35%, and we are the operator.

Block 31— In September 2018, we entered into a transaction (the "Hokchi Cross Assignment") with Hokchi Energy, S.A. de C.V. ("Hokchi"), a subsidiary of Pan American Energy LLC ("PAE"), to cross assign 25% PIs in our Block 2 and their Block 31. Our assignment of a 25% PI in Block 2 to Hokchi closed on December 21, 2018, and Hokchi's assignment of a 25% PI in Block 31 to us closed on May 22, 2019. Following the completion of the Hokchi Cross Assignment, we owned a 25% PI in Block 31, and Hokchi was the operator.

In July 2019, we spud the first project on Block 31, the Xaxamani-2EXP well. This is the first well in the Xaxamani project area, which is a shallow oil project set up by the Xaxamani-1 exploratory well drilled in 2003, which logged oil pay in several intervals. Also in the third quarter of 2019, PAE drilled the exploratory well, Tolteca-1EXP. A successful drill-stem test on the Xaxamani-2EXP confirmed productivity by producing oil to the surface. The two-well drilling campaign further confirmed the oil and gas discovery. The discovery is in very shallow waters and is less than two miles from shore. We hold a 25% PI in Block 31.

Summary of Reserves

The following table summarizes our estimated proved reserves as of December 31, 2020, 2019 and 2018, which are all located in the United States.

	Oil (MBbls)	Natural Gas (MMcf)	NGL (MBbls)	MBoe	Standardized Measure (in thousands)	PV -10 (in thousands)
December 31, 2020						
Proved Developed Producing	64,763	119,824	4,958	89,692		$1,556,221
Proved Developed Non-Producing	20,244	84,230	3,146	37,428		197,924
Total Proved Developed	85,007	204,054	8,104	127,120		1,754,145
Proved Undeveloped	24,300	53,154	2,754	35,913		244,340
Total Proved	109,307	257,208	10,858	163,033	$1,904,934	$1,998,485
December 31, 2019						
Proved Developed Producing	53,777	64,192	3,855	68,331		$1,837,964
Proved Developed Non-Producing	18,239	51,189	2,878	29,648		378,244
Total Proved Developed	72,016	115,381	6,733	97,979		2,216,208
Proved Undeveloped	34,738	40,617	2,248	43,756		776,814
Total Proved	106,754	155,998	8,981	141,735	$2,537,595	$2,993,022
December 31, 2018						
Proved Developed Producing	62,162	69,409	4,342	78,072		$2,510,213
Proved Developed Non-Producing	23,368	61,955	3,762	37,456		680,942
Total Proved Developed	85,530	131,364	8,104	115,528		3,191,155
Proved Undeveloped	27,009	39,660	2,592	36,211		734,108
Total Proved	112,539	171,024	10,696	151,739	$3,340,246	$3,925,263

Reconciliation of Standardized Measure to PV-10

PV-10 is a non-GAAP financial measure and differs from the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. PV-10 is a computation of the standardized measure of discounted future net cash flows on a pre-tax basis. PV-10 is equal to the standardized measure of discounted future net cash flows at the applicable date, before deducting future income taxes, discounted at 10 percent. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies without regard to the specific tax characteristics of such entities. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. PV-10, however, is not a substitute for the standardized measure of discounted future net cash flows. Our PV-10 measure and the standardized measure of discounted future net cash flows do not purport to represent the fair value of our oil and natural gas reserves.

The following table provides a reconciliation of the standardized measure of discounted future net cash flows to PV-10 of our proved reserves at December 31, 2020, 2019 and 2018 (in thousands).

	Year Ended December 31,		
	2020	2019	2018
Standardized measure	$ 1,904,934	$ 2,537,595	$ 3,340,246
Present value of future income taxes discounted at 10%	93,551	455,427	585,017
PV-10 (Non-GAAP)	$ 1,998,485	$ 2,993,022	$ 3,925,263

Changes in Proved Developed Reserves

The following table discloses our estimated changes in proved developed reserves during the year ended December 31, 2020:

	Oil, Natural Gas and NGLs
	(MBoe)
Proved developed reserves at December 31, 2019	97,979
Changes during the year:	
Production	(19,999)
Revisions of previous estimates	(12,167)
Additions	4,749
Acquired	49,392
Conversion to Proved Developed Producing reserves	7,166
Total proved developed reserves changes	29,141
Proved developed reserves at December 31, 2020	127,120

***Revisions of Previous Estimates* —** Downward revisions of 12.2 MMBoe are primarily attributable to a decrease in commodity prices and differentials across our core areas and 2.9 MMBoe of performance revisions in the Green Canyon core area.

***Additions* —** Additions of 4.7 MMBoe are primarily attributable to the successful drilling in the Claiborne Field located in the Mississippi Canyon core area and Green Canyon 18 Field located in the Green Canyon core area.

***Acquired* —** Acquired proved developed reserves of 49.4 MMBoe are attributable to the ILX and Castex Acquisition, the Castex 2005 Acquisition and the LLOG Acquisition located within the Mississippi Canyon and the Shelf and Gulf Coast core area. See Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations for additional information regarding each of our acquisitions.

Development of Proved Undeveloped Reserves

The following table discloses our estimated proved undeveloped ("PUD") reserve activities during the year ended December 31, 2020:

	Oil, Natural Gas and NGLs	**Future Development Costs**
	(MBoe)	(in thousands)
Proved undeveloped reserves at December 31, 2019	43,756	$ 501,660
Changes during the year:		
Extensions and discoveries	—	—
Revisions of previous estimates	(12,028)	(182,705)
Acquired	11,351	71,413
Conversion to Proved Developed Producing reserves	(7,166)	(74,915)
Total proved undeveloped reserves changes	(7,843)	(186,207)
Proved undeveloped reserves at December 31, 2020	35,913	$ 315,453

Our PUD reserves at December 31, 2020 decreased by 7.8 MMBoe, or 18% primarily due to:

***Revisions of Previous Estimates* —** Downward revisions of 12.0 MMBoe are primarily attributable to a decrease in commodity prices and differentials across our core areas and 3.2 MMBoe of technical revisions.

***Acquired* —** Acquisitions of 11.4 MMBoe of PUD reserves are attributable to the ILX and Castex Acquisition located within the Mississippi Canyon and the Shelf and Gulf Coast core area.

***Conversion to Proved Developed Producing* —** During 2020, we converted 7.2 MMBoe of proved undeveloped reserves to proved developed primarily attributable to successful platform drilling rig campaign in our Green Canyon 18 Field located in the Green Canyon core area.

We annually review all PUD reserves to ensure an appropriate plan for development exists. Our PUD reserves are required to be converted to proved developed reserves within five years of the date they are first booked as PUD reserves. Future development costs associated with our PUD reserves at December 31, 2020 totaled approximately $315.5 million, of which $289.0 million is attributable to the Mississippi Canyon and Green Canyon core areas. When considering capital expenditures associated with other exploration projects and abandonment obligations, we expect to fund the development of PUD reserves using cash flows from operations and, if needed, availability under the Company's senior reserve-based revolving credit facility (the "Bank Credit Facility"), in each future annual period prior to the five year expiration. Our 2021 drilling program includes development of PUD reserves, and the conversion rate may not be uniform due to obligatory wells, newly acquired PUD reserves and production performance targets.

Internal Controls over Reserve Estimates and Reserve Estimation Procedures

At December 31, 2020, 2019 and 2018, proved oil, natural gas and NGL reserves attributable to our net interests in oil and natural gas properties were estimated and compiled for reporting purposes by our reservoir engineers and audited by Netherland, Sewell & Associates, Inc. ("NSAI"), independent petroleum engineers and geologists, as described in further detail below.

Our policies regarding internal controls over the determination of reserves estimates require reserves quantities, reserves categorization, future producing rates, future net revenue and the present value of such future net revenue prepared using the definitions set forth in Regulation S-X, Rule 4-10(a) and subsequent SEC staff interpretations and guidance. These internal controls, which are intended to ensure reliability of our reserves estimations, include, but are not limited to, the following:

- Reserve information, as well as models used to estimate such reserves, is stored on secure database applications to which only authorized personnel are given access rights consistent with their assigned job function.
- A comparison of historical expenses is made to the lease operating costs in the reserve database.
- Internal reserves estimates are reviewed by well and by area by our reservoir engineers. A variance analysis by well to the previous year-end reserve report is performed.
- Reserve estimates are reviewed and approved by certain members of senior management, including our President and Chief Executive Officer.
- We engaged NSAI to perform an independent audit of our processes and the reasonableness of our estimates of proved reserves at December 31, 2020, 2019 and 2018. Our management requires that the independent petroleum engineers and geologists and our reserve quantities and calculation of the net present value of the reserves, collectively, vary by no more than 10% in the aggregate, in accordance with Society of Petroleum Evaluation Engineers ("SPEE") auditing standards.
- Data is transferred to NSAI through a secure file transfer protocol site.
- Material reserve variances are discussed among NSAI, as applicable, our internal reservoir engineers and our Director of Reserves to ensure the best estimate of remaining reserves.

Because these estimates depend on many assumptions, any or all of which may differ substantially from actual results, reserve estimates may be different from the quantities of oil, natural gas and NGLs that are ultimately recovered.

During the reserves audit, NSAI did not independently verify the accuracy and completeness of information and data furnished by us with respect to ownership interests, oil, natural gas and NGL production, well test data, historical costs of operation and development, product prices or any agreements relating to current and future operations of the fields and sales of production. However, if in the course of the examination something came to the attention of NSAI that brought into question the validity or sufficiency of any such information or data, NSAI did not rely on such information or data until it had satisfactorily resolved its questions relating thereto or had independently verified such information or data. When compared on a well by well basis, some of our estimates are greater and some are less than the estimates of NSAI. Given the inherent uncertainties and judgments that go into estimating proved reserves, differences between internal and external estimates are to be expected. NSAI determined that its estimates of reserves have been prepared in accordance with the definitions and regulations of the SEC, including the criteria of "reasonable certainty," as it pertains to expectations about the recoverability of reserves in future years, under existing economic and operating conditions, consistent with the definition in Rule 4-10(a)(24) of Regulation S-X. NSAI issued unqualified audit opinions on our reserves as of December 31, 2020, 2019 and 2018 based upon its evaluations. NSAI concluded that our estimates of reserves were, in the aggregate, reasonable and have been prepared in accordance with Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPEE. The NSAI reports are filed as exhibits to this Annual Report.

Technologies Used in Reserve Estimation

The SEC's reserves rules allow the use of techniques that have been proved effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil, natural gas and/or NGLs actually recovered will equal or exceed the estimate. To achieve reasonable certainty, our internal reservoir engineers employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information and property ownership interests. The accuracy of the estimates of our reserves is a function of:

- the quality and quantity of available data and the engineering and geological interpretation of that data;
- estimates regarding the amount and timing of future operating costs, development costs and workovers, all of which may vary considerably from actual results;
- future prices of oil, natural gas and NGLs, which may vary considerably from those mandated by the SEC; and
- the judgment of the persons preparing the estimates.

Qualifications of Primary Internal Engineer

Our Director of Reserves is the technical person primarily responsible for overseeing the preparation of our internal reserve estimates and for coordinating reserve audits conducted by NSAI. He has over 46 years of industry experience with positions of increasing responsibility, including 38 years as a reserves evaluator or manager. His further professional qualifications include a State of Texas Professional Engineering License, extensive internal and external reserve training and asset evaluation. In addition, he is an active participant in industry reserve seminars and professional industry groups, and has been a member of the Society of Petroleum Engineers ("SPE") for over 46 years. He reports directly to our Vice President of Corporate Development.

Drilling Activity

The following table sets forth our drilling activity during the years ended December 31, 2020, 2019 and 2018:

	Exploratory and Appraisal Wells						Development Wells							
	Productive[1]		Dry[2]		Total		Productive[1]		Dry[2]		Total		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
December 31, 2020														
United States[3]	2.0	0.7	—	—	2.0	0.7	3.0	1.9	—	—	3.0	1.9	5.0	2.6
Mexico	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	2.0	0.7	—	—	2.0	0.7	3.0	1.9	—	—	3.0	1.9	5.0	2.6
December 31, 2019														
United States	3.0	2.3	1.0	0.8	4.0	3.1	3.0	2.7	—	—	3.0	2.7	7.0	5.8
Mexico	—	—	2.0	0.5	2.0	0.5	—	—	—	—	—	—	2.0	0.5
Total	3.0	2.3	3.0	1.3	6.0	3.6	3.0	2.7	—	—	3.0	2.7	9.0	6.3
December 31, 2018														
United States	—	—	1.0	0.1	1.0	0.1	5.0	5.0	—	—	5.0	5.0	6.0	5.1
Mexico	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	—	—	1.0	0.1	1.0	0.1	5.0	5.0	—	—	5.0	5.0	6.0	5.1

(1) A productive well is an exploratory or development well found to be capable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas producing well. Productive wells are included in the table in the year they were determined to be productive, as opposed to the year the well was drilled.
(2) A dry well is an exploratory or development well that is not a productive well. Dry wells are included in the table in the year they were determined not to be productive, as opposed to the year the well was drilled.
(3) 1 gross and net development well had a dual completion in an exploratory zone.

As of December 31, 2020, we had wells actively drilling or completing and wells suspended or awaiting completion, as follows:

	Actively Drilling or Completing				Wells Suspended or Waiting on Completion			
	Exploratory		Development		Exploratory		Development	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
United States	—	—	—	—	1.0	0.3	—	—
Mexico	—	—	—	—	6.0	2.0	—	—
Total	—	—	—	—	7.0	2.3	—	—

Productive Wells

The number of our productive wells is as follows for the year ended December 31, 2020:

	Gross	Net
Crude oil	210.0	140.4
Natural gas	86.0	42.2
Total[1]	296.0	182.6

(1) Includes 8.0 gross and 8.0 net wells with dual completions.

Acreage

Gross and net developed and undeveloped acreage is as follows for the year ended December 31, 2020:

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
United States						
Deepwater	303,953	140,948	543,716	223,964	847,669	364,912
Shelf	351,482	206,911	147,310	101,105	498,792	308,016
Total United States	655,435	347,859	691,026	325,069	1,346,461	672,928
Mexico	—	—	122,356	36,332	122,356	36,332
Total	655,435	347,859	813,382	361,401	1,468,817	709,260

Undeveloped acreage is considered to be those leased acres 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 or not such acreage contains proved reserves. Included within undeveloped acreage are those leased acres (held by production under the terms of a lease) that are not within the spacing unit containing, or acreage assigned to, the productive well holding such lease. The terms of our leases on undeveloped acreage as of December 31, 2020 are scheduled to expire as shown in the table below (the terms of which may be extended by drilling and production operations):

	Gross	Net
2021	96,276	30,434
2022	145,482	49,399
2023	188,488	127,024
2024	107,480	37,710
2025	46,166	25,778
2026 and beyond	229,490	91,056
Total	813,382	361,401

Crude Oil, Natural Gas and NGL Production, Prices and Production Costs

Our production volumes, average sales prices and average production costs are as follows:

	Year Ended December 31,		
	2020	2019	2018
Production Volumes:			
Crude oil (MBbls)	13,665	13,847	11,771
Natural gas (MMcf)	28,652	23,306	22,771
NGLs (MBbls)	1,559	1,228	1,176
Total (MBoe)	19,999	18,959	16,742
Percent of Boe from crude oil	68%	73%	70%
Average Sales Price (including commodity derivatives):			
Crude oil (Per Bbl)	$ 47.36	$ 59.23	$ 57.12
Natural gas (Per Mcf)	$ 2.00	$ 2.55	$ 3.16
NGLs (Per Bbl)	$ 9.90	$ 16.02	$ 30.50
Average (Per Boe)	$ 35.99	$ 47.43	$ 46.60
Average Sales Price (excluding commodity derivatives):			
Crude oil (Per Bbl)	$ 37.09	$ 60.17	$ 66.42
Natural gas (Per Mcf)	$ 1.87	$ 2.37	$ 3.23
NGLs (Per Bbl)	$ 9.90	$ 16.02	$ 30.50
Average (Per Boe)	$ 28.80	$ 47.90	$ 53.24
Average Lease Operating Expense (Per Boe)	$ 12.33	$ 12.84	$ 13.52

Crude Oil, Natural Gas and NGL Production, Prices and Production Costs—Significant Fields

Green Canyon Core Area — Phoenix Field

The following table sets forth certain information regarding our production volumes, average sales prices and average production costs for the Phoenix Field, which consisted of 15% or more of our total estimated proved reserves at December 31, 2020, 2019 and 2018:

	Year Ended December 31,		
	2020	2019	2018
Production Volumes:			
Crude oil (MBbls)	4,000	4,812	5,160
Natural gas (MMcf)	3,552	4,803	5,311
NGLs (MBbls)	345	368	491
Total (MBoe)	4,937	5,980	6,536
Percent of Boe from crude oil	81%	80%	79%
Average Sales Price (excluding commodity derivatives):			
Crude oil (Per Bbl)	$ 37.53	$ 59.72	$ 65.11
Natural gas (Per Mcf)	$ 2.22	$ 2.74	$ 3.57
NGLs (Per Bbl)	$ 12.70	$ 15.68	$ 29.04
Average (Per Boe)	$ 32.89	$ 51.23	$ 56.48
Average Lease Operating Expense (Per Boe)	$ 6.12	$ 5.90	$ 4.35

Mississippi Canyon Core Area — Pompano Field

The following table sets forth certain information regarding our production volumes, average sales prices and average production costs for the Pompano Field, which consisted of 15% or more of our total estimated proved reserves at December 31, 2020, 2019 and 2018:

	Year Ended December 31,		
	2020	2019	2018[(1)]
Production Volumes:			
Crude oil (MBbls)	2,852	3,324	2,042
Natural gas (MMcf)	2,179	2,320	1,758
NGLs (MBbls)	216	236	151
Total (MBoe)	3,431	3,947	2,486
Percent of Boe from crude oil	83%	84%	82%
Average Sales Price (excluding commodity derivatives):			
Crude oil (Per Bbl)	$ 38.51	$ 61.83	$ 69.06
Natural gas (Per Mcf)	$ 2.28	$ 2.61	$ 3.50
NGLs (Per Bbl)	$ 6.51	$ 14.49	$ 30.95
Average (Per Boe)	$ 33.86	$ 54.49	$ 61.08
Average Lease Operating Expense (Per Boe)	$ 2.90	$ 2.17	$ 1.88

(1) The year ended December 31, 2018 includes the period from the closing date of the Stone Combination from May 10, 2018, through December 31, 2018.

Expenditures and Costs Incurred

For information on property development, exploration and acquisition costs, see Part IV, Item 15. Exhibits, Financial Statement Schedules — Note 14 — *Supplemental Oil and Gas Disclosures (Unaudited)*.

Title to Properties

We believe that we have satisfactory title to our oil and natural gas properties in accordance with generally accepted industry standards. Individual properties may be subject to burdens such as royalties, overriding royalties, and carried, net profits, working and other outstanding interests customary in the industry. In addition, interests may be subject to obligations or duties under applicable laws or burdens such as production payments, ordinary course liens incidental to operating agreements and for current taxes and development obligations under oil and natural gas leases. As is customary in the industry in the case of undeveloped properties, often limited investigation of record title is made at the time of acquisition. Title search investigations are made prior to the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties. To the extent title opinions or other investigations reflect defects affecting such undeveloped properties, we are typically responsible for curing any such title defects at our expense.

Commodity Price Risks and Price Risk Management Activities

Production from our properties is marketed using methods that are consistent with industry practices. Sales prices for oil and natural gas production are negotiated based on factors normally considered in the industry, such as an index or spot price, price regulations, distance from the well to the pipeline, commodity quality and prevailing supply and demand conditions. We enter into derivative contracts on our oil and natural gas production primarily to stabilize cash flows and reduce the risk and financial impact of downward commodity price movements on commodity sales. For additional information regarding our commodity price risk and commodity derivative instruments, see Part II, Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

Significant Customers

Oil and natural gas companies spend capital on exploration, drilling and production operations expenditures, the amount of which is generally dependent on the prevailing view of future oil and natural gas prices which are subject to many external factors which may contribute to significant volatility in future prices. We market substantially all of our oil, natural gas and NGL production from the properties we operate and those we do not operate. Our customers consist primarily of major oil and gas companies, well-established oil and pipeline companies and independent oil and natural gas producers and suppliers. We perform ongoing credit evaluations of our customers and provide allowances for probable credit losses when necessary. For the year ended December 31, 2020, 47%, 22%, and 12% of our oil, natural gas and NGL revenues were attributable to Shell Trading (US) Company, Phillips 66 and Chevron Products Company, respectively, which are the customers that individually represented 10% or more of our oil, natural gas and NGL revenues.

Competitive Conditions

The oil and natural gas business is highly competitive in the exploration for and acquisition of reserves, the acquisition of oil and natural gas leases, equipment and personnel required to find and produce reserves and in the gathering and marketing of oil, natural gas and NGLs. We compete with large integrated oil and natural gas companies as well as independent exploration and production companies. Certain of our competitors may have significantly more financial or other resources available to them. In addition, certain of the larger integrated companies may be better able to respond to industry changes, including price fluctuation, oil and natural gas demand and governmental regulations.

However, we believe our high quality oil-weighted production base, proven expertise in utilizing seismic technology to identify, evaluate and develop exploitation and exploration opportunities, balanced mix of assets in the U.S. Gulf of Mexico deep and shallow waters and significant operating control give us a strong competitive position relative to many of our competitors.

Seasonality of Business

Weather conditions affect the demand for, and prices of, oil and natural gas. Due to these seasonal fluctuations, our results of operations for individual quarterly periods may not be indicative of the results that may be realized on an annual basis. Generally, but not always, the demand for gas decreases during the summer months and increases during the winter months. Seasonal anomalies such as mild winters or hot summers may impact general seasonal changes in demand.

Insurance Matters

Our oil and natural gas operations are subject to risks incident to the operation of oil and gas wells, including but not limited to uncontrolled flows of oil, gas, brine or well fluids into the environment, blowouts, cratering, mechanical difficulties, fires, explosions or other physical damage, pollution or other risks, any of which could result in substantial losses to us. In addition, our oil and natural gas properties are located in the U.S. Gulf of Mexico, which makes us more vulnerable to tropical storms and hurricanes. These hazards can cause personal injury or loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and the suspension of operations. Damages arising from such occurrences may result in lawsuits asserting large claims. Insurance may not be sufficient or effective under all circumstances or against all hazards to which we may be subject. A successful claim for which we are not fully insured could have a material adverse effect on our financial condition, results of operations and cash flow. Although we obtain insurance against some of these risks, we cannot insure against all possible losses. As a result, any damage or loss not covered by insurance could have a material adverse effect on our financial condition, results of operations and cash flow.

We have insurance policies to cover some of our risk of loss associated with our operations, and we maintain the amount of insurance we believe is prudent. However, not all of our business activities can be insured at the levels we desire because of either limited market availability or unfavorable economics (limited coverage for the underlying cost).

Our general property damage insurance provides varying ranges of coverage based upon several factors, including well counts and the cost of replacement facilities. Our general liability insurance program provides a limit of $500 million for each occurrence and in the aggregate, and includes varying deductibles. Our Offshore Pollution Act insurance is subject to a maximum of up to $150 million for each occurrence and in the aggregate, including a $100,000 retention. Coverage is provided for damage to our assets resulting from a named U.S. Gulf of Mexico windstorm; however, such coverage is subject to a maximum of $170 million per named windstorm and in the aggregate, and is also subject to a maximum of $35 million per occurrence retention. We separately maintain an operators extra expense policy with additional coverage for an amount up to $500 million for U.S. Gulf of Mexico deepwater drilling wells, $150 million for U.S. Gulf of Mexico shelf drilling wells, $75 million for U.S. Gulf of Mexico producing and shut-in wells, $75 million for drilling and workover in inland waters and $25 million for drilling and workover in onshore fields that would cover costs involved in making a well safe after a blow-out or getting the well under control; re-drilling a well to the depth reached prior to the well being out of control or blown out; costs for plugging and abandoning the well; and costs for clean-up and containment and for damages caused by contamination and pollution. For our Mexico insurance policies, we maintain $250 million in operators extra expense coverage for operations and $500 million per occurrence and aggregate limit for general liability.

We may increase or decrease insurance coverage around our key strategic assets, including potentially purchasing catastrophic bond instruments. Our highest value assets, which are located in the Phoenix Field, produce through the HP-I floating production system, which has the capability to disconnect and move away in the event of a storm, mitigating the risk of property damage.

We customarily have reciprocal agreements with our customers and vendors in which each contracting party is responsible for its respective personnel for liability related to work performed for us. Under these agreements, we generally are indemnified against third party claims related to the injury or death of our customers' or vendors' personnel, subject to the application of various states' laws.

Government Regulation

Exploration and development and the production and sale of oil, natural gas and NGLs are subject to extensive federal, state, local and foreign laws and regulations. An overview of these legal requirements is set forth below. Historically, our compliance with existing requirements has not had a material adverse effect on our financial position, results of operations or cash flows. However, current regulatory requirements may change, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered. Because such laws and regulations are frequently amended or reinterpreted, we are unable to predict the future cost or impact of complying with such laws. 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 others in our industry with similar types, quantities and locations of production.

General Overview — Our oil and natural gas operations are subject to various federal, state, local and foreign laws and regulations. Generally speaking, these regulations relate to matters that include, but are not limited to:

- location of wells;
- size of drilling and spacing units or proration units;
- number of wells that may be drilled in a unit;
- unitization or pooling of oil and natural gas properties;
- drilling and casing of wells;
- issuance of permits in connection with exploration, drilling and production;
- well production;
- spill prevention plans;
- protection of private and public surface and ground water supplies;
- emissions permitting or limitations;
- protection of endangered species;
- use, transportation, storage and disposal of fluids and materials incidental to oil and natural gas operations;
- surface usage and the restoration of properties upon which wells have been drilled;
- calculation and disbursement of royalty payments and production taxes;
- requirements for the posting of supplemental bonds or providing other forms of financial assurance for the plugging and abandonment of wells located in the U.S. Gulf of Mexico and offshore Mexico and, following cessation of operations, the removal or appropriate abandonment of all production facilities, structures and pipelines in those areas (“P&A” or “decommissioning” obligations);
- performance of P&A obligations; and
- transportation of production.

Outer Continental Shelf (“OCS”) Regulation — Our operations on federal oil and natural gas leases in the U.S. Gulf of Mexico are subject to regulation by the Bureau of Safety and Environmental Enforcement (“BSEE”), the Bureau of Ocean Energy Management (“BOEM”) and the Office of Natural Resources Revenue (“ONRR”), which are all agencies of the U.S. Department of the Interior (“DOI”). These leases are awarded by the BOEM based on competitive bidding and contain relatively standardized terms and require compliance with detailed BSEE and BOEM regulations and orders issued pursuant to various federal laws, including the federal Outer Continental Shelf Lands Acts (“OCSLA”). For offshore operations, lessees must obtain BOEM approval for exploration, development and production plans prior to the commencement of their operations. In addition to permits required from other agencies such as the U.S. Environmental Protection Agency (“EPA”), lessees must obtain a permit from BSEE prior to the commencement of drilling and comply with regulations governing, among other things, engineering and construction specifications for production facilities, safety procedures, P&A of wells on the OCS, calculation of royalty payments and the valuation of production for this purpose, and removal of facilities.

Recent orders issued under the new Biden Administration have served to temporarily halt new leasing and new drilling opportunities on the OCS, which specifically excludes authorizations associated with existing operations under valid leases. In particular, the Acting Secretary of the U.S. Department of the Interior under the Biden Administration issued an order on January 20, 2021, effective immediately, that suspends the delegation of authority to the bureaus and agencies of the DOI to approve any new oil and gas leases and new drilling permits on federal lands and offshore waters, including the OCS for a period of 60 days. Building on this suspension, President Biden issued an executive order on January 27, 2021 that suspends new leasing activities for oil and gas exploration and production on federal lands and offshore waters pending review and reconsideration of federal oil and gas permitting and leasing practices. While the January 27, 2021 order does not apply to existing leases, the January 27, 2021 order further directs applicable agencies to take measures to eliminate provision of subsidies to the fossil fuel industry from budget requests beginning in 2022.

Laws and regulations are subject to change, and the trend in the United States over the past decade has been for these governmental agencies to continue to evaluate and as necessary develop and implement new, more restrictive safety, permitting and performance requirements, although in recent years under the Trump Administration there have been actions seeking to mitigate certain of those more rigorous standards. For example, in 2016, BSEE under the Obama Administration published a final rule on well control that, among other things, imposed rigorous standards relating to the design, operation and maintenance of blow-out preventers, real-time monitoring of deepwater, high temperature, high pressure drilling activities, and enhanced reporting requirements. However, BSEE under the Trump Administration subsequently reconsidered the 2016 final rule and published final revisions to this rule that became effective in 2019 and, among other things, eliminated the requirement for a BSEE-approved verification organization for third parties providing certifications of certain critical well control functions. In another example, BSEE under the Obama Administration published a final rule in 2016 updating certain safety and pollution prevention equipment (e.g., subsea safety equipment, including blowout preventers) requirements for production safety equipment, including an obligation for independent third-party review and certification that safety and pollution prevention equipment is operational and functioning as designed in the most extreme conditions, but in 2018, BSEE amended this rule, rolling back a number of safety requirements including the third-party review and certification obligation.

With the change in Presidential Administrations in January 2021, it is possible that BSEE and/or BOEM may reconsider regulatory actions taken by the prior Administration and that they may seek to adopt additional, more stringent safety, permitting and performance requirements. Compliance with Biden Administration legislative, executive and regulatory actions or any other legal initiatives that impact oil and natural gas exploration, development and production activities on the OCS could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business. In addition, under certain circumstances, BSEE may require our operations on federal leases to be suspended or terminated. Any such suspension or termination could adversely affect our financial condition and operations.

Furthermore, hurricanes in the Gulf of Mexico can have a significant impact on oil and natural gas operations. The effects from past hurricanes have included structural damage to fixed production facilities, semi-submersibles and jack-up drilling rigs. The BOEM and BSEE continue to be concerned about the loss of these facilities and rigs as well as the potential for catastrophic damage to key infrastructure and the resultant pollution from future storms. In an effort to reduce the potential for future damage, the BOEM and the BSEE have periodically issued guidance aimed at improving platform survivability by taking into account environmental and oceanic conditions in the design of platforms and related structures. It is possible that similar, if not more stringent, requirements will be issued by the BOEM and the BSEE for future hurricane seasons. New requirements, if any, could increase our operating costs and/or capital expenditures.

In addition, in order to cover the various decommissioning obligations of lessees on the OCS, the BOEM generally requires that lessees post some form of acceptable financial assurances that such obligations will be met, such as surety bonds. The cost of such bonds or other financial assurance can be substantial, and we can provide no assurance that we can continue to obtain bonds or other surety in all cases. The BOEM requires that lessees demonstrate financial strength and reliability according to its regulations and provide acceptable financial assurances to assure satisfaction of lease obligations, including decommissioning activities on the OCS. In 2016, the BOEM under the Obama Administration issued Notice to Lessees and Operators ("NTL") #2016-N01 ("2016 NTL") to clarify the procedures and guidelines that BOEM Regional Directors use to determine if and when additional financial assurances may be required for OCS leases, rights of way ("ROWs") and rights of use and easement ("RUEs"). While the 2016 NTL became effective in September 2016, it was not fully implemented as the BOEM under the Trump Administration first extended indefinitely in 2017 implementation of the NTL and subsequently rescinded the NTL in the latter half of 2020. The Trump Administration instead elected to pursue a proposed rule published jointly by the BOEM and the BSEE in October 2020 that seeks to clarify and provide greater transparency to decommissioning and related financial assurance requirements imposed on oil and gas lessees (record title owners), sublessees (operating rights owners) and RUE and ROW grant holders conducting operations on the federal OCS. With the change in Presidential Administrations in January 2021, it is possible that the October 2020 proposed rule will not be implemented and that other, possibly more stringent, final assurance requirements may ultimately be imposed.

The future cost of compliance with respect to supplemental bonding, including the obligations imposed on us, whether as current or predecessor lessee or grant holder, as a result of the 2016 NTL, to the extent re-implemented or the October 2020 proposed rule, to the extent finalized, as well as to the provisions of any new, more stringent, NTLs or final rules on supplemental bonding published by the BOEM under the Biden Administration, could materially and adversely affect our financial condition, cash flows and results of operations. Moreover, the BOEM has the right to issue liability orders in the future, including if it determines there is a substantial risk of nonperformance of the interest holder's decommissioning liabilities.

Regulation in Shallow Waters Off the Coast of Mexico — Our operations on oil and natural gas blocks in shallow waters off the coast of Mexico's Veracruz and Tabasco states and in other Mexican offshore areas where we are assessing other exploration opportunities, are subject to regulation by SENER, the CNH and other Mexican regulatory bodies. The CNH is responsible for, among other things, overseeing the tender procedures for awarding contracts for the exploration and production of oil and natural gas in Mexican waters, managing and supervising contracts that have been awarded, and approving exploration and production plans. The PSCs that we and our consortium partners have entered into for the development of these acreages contain terms that impose on us the duty to comply with various laws and regulations. These laws and regulations govern, among other things, the exploration and exploitation of hydrocarbons (including certain national content requirements), the treatment, conveyance, marketing, transport and storage of petroleum, and requirements for industrial safety, operational security, and facility decommissioning. Failure to comply can result in the imposition of monetary penalties, revocation of permits, rescission of the relevant PSC, suspension of operations, and ordered decommissioning of offshore facilities and systems. The laws and regulations governing activities in the Mexican energy sector are relatively new, having been significantly reformed in 2013, and the legal regulatory framework continues to evolve as SENER, the CNH and other Mexican regulatory bodies issue new regulations and guidance. Such regulations are subject to change, and it is possible that SENER, the CNH or other Mexican regulatory bodies may impose new or revised requirements that could increase our operating costs and/or capital expenditures for operations in Mexican offshore waters.

Hydrocarbon Export Regulation in Mexico — Our operations on oil and natural gas blocks in shallow waters off the coast of Mexico's Veracruz and Tabasco states, and in other Mexican offshore areas where we are assessing other exploration opportunities, are subject to regulation by SENER. Such regulations are subject to change, and it is possible that ASEA or other Mexican regulatory bodies may impose new or revised requirements that could increase our operating costs and/or capital expenditures for operations in Mexican offshore waters. For example, on December 26, 2020, SENER published new regulations affecting the granting of permits for the import and export of hydrocarbons. These new regulations impose additional constraints on permit applicants, and grant SENER more discretion in issuing, modifying, and revoking those permits. Previously, such permits would have a term of 20 years – the new regulations limit terms to 5 years, restrict extensions, and add new requirements.

Some oil and gas companies, and Amexhi, a trade group comprised of oil and gas operators in Mexico, have filed Amparo proceedings, seeking a declaration that such regulations are unconstitutional. In February 2021, a Federal Judge in Mexico granted a general injunction which temporarily blocks the enforceability of these new regulations.

Environmental and Occupational Safety and Health Regulations

We are subject to various federal, state, local and foreign regulations concerning occupational safety and health as well as the discharge of materials into, and the protection of, the environment. Environmental laws and regulations relate to, among other things:

- assessing the environmental impact of seismic acquisition, drilling or construction activities;
- the generation, storage, transportation and disposal of waste materials;
- the emission of certain gases into the atmosphere;
- the monitoring, abandonment, reclamation and remediation of well and other sites, including sites of former operations;
- various environmental permitting requirements, such as permits for wastewater discharges;
- the development of emergency response and spill contingency plans;
- specific operating criteria addressing worker protection; and
- protection of private and public surface and ground water supplies.

Based on regulatory trends and increasingly stringent laws, our capital expenditures and operating expenses related to the protection of the environment and safety and health compliance have increased over the years and it is possible such expenses will continue to increase under the Biden Administration. We cannot predict with any reasonable degree of certainty our future exposure concerning such matters, and the cost of compliance could be significant. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, natural resource damages or the issuance of injunctive relief (including orders to cease operations). Both onshore and offshore drilling in certain areas has been opposed by environmental groups and, in certain areas, has been restricted. Additionally, President Biden has made the combat of climate change arising from GHG emissions a priority under his Administration and orders have already been issued to temporarily halt new leasing and new drilling opportunities, excluding authorizations for existing operations under valid leases, on the OCS, and additional orders or new legislative or regulatory initiatives regarding the restriction, delay or cancellation of such new or existing activities could be issued in the future. Moreover, some environmental laws and regulations may impose strict liability, which could subject us to liability for conduct that was lawful at the time it occurred or conduct or conditions caused by prior operators or third parties. To the extent laws are enacted or other governmental action is taken that prohibits or restricts onshore or offshore drilling or imposes environmental protection requirements that result in increased costs to the oil and gas industry in general, our business and financial results could be adversely affected.

We expect to continue making expenditures on a regular basis relating to environmental compliance. We maintain insurance coverage for spills, pollution and certain other environmental risks, although we are not fully insured against all such risks. Our insurance coverage provides for the reimbursement to us of certain costs incurred for the containment and clean-up of materials that may be suddenly and accidentally released in the course of our operations, but such insurance does not fully insure against pollution and similar environmental risks. We do not anticipate that we will be required under current environmental laws and regulations to expend amounts that will have a material adverse effect on our consolidated financial position or our results of operations. However, since environmental costs and liabilities are inherent in our operations and in the operations of companies engaged in similar businesses and since regulatory requirements frequently change and may become more stringent under the Biden Administration, there can be no assurance that material costs and liabilities will not be incurred in the future. Such costs may result in increased costs of operations and acquisitions and decreased production.

Water Discharges — Our discharges into waters of the United States are limited by the federal Clean Water Act, as amended ("CWA"), and analogous state laws. The CWA prohibits any discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States, except in compliance with permits issued by federal and state governmental agencies. These discharge permits also include monitoring and reporting obligations. Failure to comply with the CWA, including discharge limits set by permits issued pursuant to the CWA, may also result in administrative, civil or criminal enforcement actions. Violations of the CWA can result in suspension, debarment or the imposition of statutory disability, each of which prevents companies and individuals from participating in government contracts and receiving some non-procurement government benefits. The CWA also requires the preparation of oil spill response plans and spill prevention, control and countermeasure plans.

Oil Pollution Act — The Oil Pollution Act of 1990, as amended ("OPA"), holds owners and operators of offshore oil production or handling facilities, including the lessee or permittee of the area where an offshore facility is located, strictly liable for the costs of removing oil discharged into waters of the United States and for certain damages from such spills. OPA assigns joint and several strict liability, without regard to fault, to each liable party for all containment and oil removal costs and a variety of public and private damages including, but not limited to, the costs of responding to a release of oil, natural resource damages and economic damages suffered by persons adversely affected by an oil spill. Although defenses exist to the liability imposed by OPA, they are limited. OPA's damages liability cap is currently $137.7 million; however, a party cannot take advantage of liability limits if a spill was caused by gross negligence or willful misconduct, resulted from violation of a federal safety, construction or operating regulation, or if the party failed to report a spill or cooperate fully in the clean-up. OPA also requires responsible parties to maintain evidence of financial responsibility in prescribed amounts. OPA currently requires a minimum financial responsibility demonstration of between $35 million to $150 million, based on a worst case oil spill discharge volume, for companies operating on the OCS, although the BOEM may increase this amount in certain situations, but in no event greater than $150 million. From time to time, the United States Congress has proposed, but not adopted, amendments to OPA raising the financial responsibility requirements. If OPA is amended to increase the minimum level of financial responsibility, we may experience difficulty in providing financial assurances sufficient to comply with this requirement. We cannot predict at this time whether OPA will be amended or whether the level of financial responsibility required for companies operating on the OCS will be increased. In any event, if an oil discharge or substantial threat of discharge were to occur, we may be liable for costs and damages, which costs and liabilities could be material to our results of operations and financial position.

National Environmental Policy Act — The National Environmental Policy Act, as amended ("NEPA"), requires federal agencies, including the DOI, to consider the impacts their actions have on the human environment, and to prepare detailed statements for major federal actions having the potential to significantly impact the environment. These requirements can lead to additional costs and delays in permitting for operators as the DOI or its bureaus may need to prepare Environmental Assessments ("EA") and more detailed Environmental Impact Statements ("EIS") in support of its leasing and other activities that have the potential to significantly affect the quality of the environment. If the EA indicates that no significant impact is likely, then the agency can release a finding of no significant impact and carry on with the proposed action. Otherwise, the agency must then conduct a full-scale EIS. On July 16, 2020, the Council on Environmental Quality ("CEQ") under former President Trump's Administration published a final rule modifying the NEPA. The modified final rule establishes a time limit of two years for preparation of EIS statements and one year for the preparation of EAs. The modified rule also eliminates the responsibility to consider cumulative effects of a project. The new regulations are subject to ongoing litigation in several federal district courts, and future implementation of the regulations is unclear. The NEPA process involves public input through comment. These comments, as well as the agency's analysis of the proposed project, can result in changes to the nature of a proposed project, such as by limiting the scope of the project or requiring resource-specific mitigation. The adequacy of the agency's NEPA process can be challenged in federal court by process participants. This process may result in delaying the permitting and development of projects, and result in increased costs.

Endangered Species Act — The Endangered Species Act, as amended ("ESA"), restricts activities that may affect federally identified endangered and threatened species or their habitats. Additionally, the Migratory Bird Treaty Act, as amended ("MBTA"), implements various treaties and conventions between the United States and certain other nations for the protection of migratory birds. Under the MBTA, the taking, killing or possessing of migratory birds is unlawful without a permit. The U.S. Fish and Wildlife Service ("FWS") under former President Trump issued a final rule on January 7, 2021, which notably clarifies that criminal liability under the MBTA will apply only to actions "directed at" migratory birds, its nests or its eggs; however, in 2020, the U.S. District Court for the Southern District of New York vacated a Department of Interior memorandum articulating a similar interpretation. The Department of Interior under President Biden delayed the effective date of the January 2021 rule and opened a public comment period for further review. The Marine Mammal Protection Act, as amended ("MMPA"), similarly prohibits the taking of marine mammals without authorization. Additionally, the FWS may make determinations on the listing of species as threatened or endangered under the ESA and litigation with respect to the listing or non-listing of certain species may result in more fulsome protections for non-protected or lesser-protected species. We conduct operations on oil and natural gas leases in areas where certain species that are protected by the ESA, MBTA and MMPA are known to exist and where other species that could potentially be protected under these statutes are known to exist. The FWS or the National Marine Fisheries Service may designate critical habitat that it believes is necessary for survival of a threatened or endangered species. A critical habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit access to protected areas for oil and natural gas development. These statutes may result in operating restrictions or a temporary, seasonal or permanent ban in affected areas.

Hazardous Substances and Waste Management — The Resource Conservation and Recovery Act, as amended ("RCRA"), generally regulates the disposal of solid and hazardous wastes and imposes certain environmental cleanup obligations. Although RCRA specifically excludes from the definition of hazardous waste "drilling fluids, produced waters and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy," the EPA and state agencies may regulate these wastes as solid wastes. However, it is possible that certain oil and natural gas drilling and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any future loss of the RCRA exclusion for drilling fluids, produced waters and related wastes could result in increased costs to manage and dispose of generated wastes. Also, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste oils, may be regulated as hazardous waste.

Comprehensive Environmental Response, Compensation and Liability Act — The Comprehensive Environmental Response, Compensation and Liability Act, as amended ("CERCLA"), and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on persons that are considered to have contributed to the release of a "hazardous substance" into the environment. Such "responsible persons" may be subject to joint and several liability under CERCLA for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources. Further, it is not uncommon for coastal landowners or other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

Air Emissions — The Clean Air Act, as amended ("CAA"), and comparable state statutes restrict the emission of air pollutants and affect both onshore and offshore oil and natural gas operations. New facilities may be required to obtain separate construction and operating permits before construction work can begin or operations may start, and existing facilities may be required to incur capital costs in order to remain in compliance. Also, the EPA has developed, and continues to develop, more stringent regulations governing emissions of toxic air pollutants and is considering the regulation of additional air pollutants and air pollutant parameters. For example, in 2015, the EPA under the Obama Administration issued a final rule under the CAA, making the National Ambient Air Quality Standard ("NAAQS") for ground-level ozone more stringent. Since that time, the EPA has issued area designations with respect to ground-level ozone and, more recently, in December 2020, the EPA, under the Trump Administration, published a final action that, upon conducting a periodic review of the ozone standard in accord with CAA requirements, elected to retain the 2015 ozone NAAQS without revision on a going-forward basis; however, several groups have filed litigation over this December 2020 decision, and this NAAQS standard may be subject to further revision under the Biden Administration. State implementation of the revised NAAQS could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits and result in increased expenditures for pollution control equipment, the costs of which could be significant.

Worker Health and Safety — The Occupational Safety and Health Act, as amended ("OSHA"), and comparable state statutes regulate the protection of the health and safety of workers. The OSHA hazard communication standard requires maintenance of information about hazardous materials used or produced in operations and provision of such information to employees. Other OSHA standards regulate specific worker safety aspects of our operations. Failure to comply with OSHA requirements can lead to the imposition of penalties.

Climate Change — Climate change continues to attract considerable public, political and scientific attention. As a result, numerous legislative and regulatory initiatives have been made, and are likely to continue to be made, at the international, national, regional and state levels of government to monitor and limit existing emissions of GHGs as well as to restrict or eliminate such future emissions. These regulatory efforts have included consideration of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs and regulations that directly limit GHG emissions from certain sources. Additionally, the threat of climate change has resulted in increasing political, litigation and financial risks associated with the production of fossil fuels and emission of GHGs. To combat climate change resulting from GHG emissions, orders have already been issued under the Biden Administration to temporarily halt new leasing and thus new drilling opportunities on the OCS. The adoption and implementation of any federal or state legislation, regulations or executive orders or the occurrence of any litigation or financial developments that impose more stringent requirements or bans on GHG-emitting production activities or locations, including the OCS, where such production activities may occur, impose liabilities for past conduct relating to GHG-emitting production activities or limit or eliminate sources of financing for on-going production operations could require us to incur increased costs of compliance or costs of consuming, and thereby reduce demand for, oil and natural gas that we produce. Moreover, climate change activism, fuel conservation measures, governmental initiatives for renewable energy resources, increasing consumer demand for alternative forms of energy, technological advances in fuel economy and energy generation devices may create new competitive conditions that result in reduced demand for the oil and natural gas we produce. Finally, 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, floods, rising sea levels and other climatic events.

Environmental Regulation in Shallow Waters Off the Coast of Mexico — Our operations on oil and natural gas blocks in shallow waters off the coast of Mexico's Veracruz and Tabasco states, and in other Mexican offshore areas where we are assessing other exploration opportunities, are subject to regulation by the Mexican National Agency of Industrial Safety and Environmental Protection of the Hydrocarbons Sector ("ASEA"). We must obtain ASEA-issued permits and comply with ASEA regulations governing hydrocarbon activities, including requirements for environmental impact and risk assessments, industrial safety, waste management, water and air emissions, operational security and facility decommissioning. Failure to comply with applicable laws and regulations can result in the imposition of monetary penalties, revocation of permits, suspension of operations and ordered decommissioning of offshore facilities and systems. The laws and regulations governing the protection of health, safety and the environment from activities in the Mexican energy sector are relatively new, having been significantly reformed following the establishment of ASEA in 2014 as a result of federal constitutional amendments approved in 2013, and the legal regulatory framework continues to evolve as ASEA and other Mexican regulatory bodies issue new regulations and guidance. Such regulations are subject to change, and it is possible that ASEA or other Mexican regulatory bodies may impose new or revised requirements that could increase our operating costs and/or capital expenditures for operations in Mexican offshore waters. For example, in May 2020, the ASEA published the Industrial Safety, Operational Safety and Environmental Protection Guidelines for the Closing, Dismantling and Abandonment of Hydrocarbons Sector Facilities (the "Dismantling Guidelines"). The Dismantling Guidelines are mandatory for all hydrocarbon sector facilities that perform dismantling, abandonment and closing of hydrocarbon sector activities. The Dismantling Guidelines set out several obligations in terms of safety, reporting and risk, including establishing a closing, dismantling and/or abandonment activities program for each of the relevant phases.

Under the PSCs, we are jointly and severally liable for the performance of all obligations under the PSCs, including exploration, appraisal, extraction and abandonment activities and compliance with all environmental regulations, and failure to perform such obligations could result in contractual rescission of the PSCs.

Federal Regulation of Sales and Transportation of Natural Gas — Our sales of natural gas are affected directly or indirectly by the availability, terms and cost of natural gas transportation. The prices and terms for access to pipeline transportation of natural gas are subject to extensive federal and state regulation. The transportation and sale for resale of natural gas in interstate commerce is regulated primarily under the Natural Gas Act of 1938 ("NGA") and the Natural Gas Policy Act of 1978 ("NGPA") and by regulations and orders promulgated under the NGA and/or NGPA by the Federal Energy Regulatory Commission ("FERC"). In certain limited circumstances, intrastate transportation and wholesale sales of natural gas may also be affected directly or indirectly by laws enacted by the United States Congress and by FERC regulations. However, certain offshore gathering and transportation services we rely upon are subject to limited FERC regulation and are regulated by the states.

Pursuant to authority delegated to it by the Energy Policy Act of 2005 ("EPAct 2005"), FERC promulgated anti-manipulation regulations establishing violation enforcement mechanisms that make it unlawful for any entity, directly or indirectly, in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to the jurisdiction of FERC to (i) use or employ any device, scheme or artifice to defraud, (ii) make any untrue statement of a material fact or to omit to state a material fact necessary in order to make the statements made, in the light of the circumstances under which they were made, not misleading or (iii) engage in any act, practice or course of business that operates or would operate as a fraud or deceit upon any entity. The EPAct 2005 also amended the NGA and the NGPA to give FERC authority to impose civil penalties for violations of these statutes and regulations, up to $1,307,164 per violation, per day for 2021 (this amount is adjusted annually for inflation). FERC may also order disgorgement of profits and corrective action. The anti-market manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of natural gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" natural gas sales, purchases or transportation subject to FERC jurisdiction, which includes annual reporting requirements for entities that purchase or sell a certain volume of natural gas in a given calendar year. We believe, however, that neither the EPAct 2005 nor the regulations promulgated by FERC as a result of the EPAct 2005 will affect us in a way that materially differs from the way they affect other natural gas producers, gatherers and marketers with which we compete.

Our sales of oil and natural gas are also subject to market manipulation and anti-disruptive requirements under the Commodity Exchange Act ("CEA") as amended by the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), and regulations promulgated thereunder by the U.S. Commodity Futures Trading Commission (the "CFTC"). The CFTC prohibits any person from manipulating or attempting to manipulate the price of any commodity in interstate commerce or futures on such commodity. The CEA also prohibits knowingly delivering or causing to be delivered false or misleading or knowingly inaccurate reports concerning market information or conditions that affect or tend to affect the price of a commodity.

The current statutory and regulatory framework governing interstate natural gas transactions is subject to change in the future, and the nature of such changes is impossible to predict. We cannot predict whether new legislation to regulate natural gas might be proposed, what proposals, if any, might actually be enacted by the United States Congress, the applicable federal agencies, or the various state legislatures, and what effect, if any, the proposals might have on our operations. The natural gas industry historically has been very heavily regulated. In the past, the federal government regulated the prices at which natural gas could be sold. Since 1978, various federal laws have been enacted that have resulted in the complete removal of all price and non-price controls for sales of domestic natural gas sold in "first sales," which include all of our sales of our own production. However, we are subject to reporting requirements imposed by FERC. There is always some risk, however, that the United States Congress may reenact price controls in the future. Changes in law and to FERC policies and regulations may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate pipelines or impose additional reporting or other requirements upon our operations, and we cannot predict what future action FERC will take. Therefore, there is no assurance that the current regulatory approach recently pursued by FERC and the United States Congress will continue. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other natural gas producers, gatherers and marketers with which we compete.

Federal Regulation of Sales and Transportation of Crude Oil — FERC regulates the interstate pipeline of crude oil, petroleum products and other liquids, such as NGLs. Our sales of crude oil and condensate are currently not regulated and are made at negotiated prices. There is always some risk, however, that the United States Congress may reenact crude oil, petroleum products and NGL price controls in the future. We cannot predict whether new legislation to regulate crude oil, or the prices charged for crude oil might be proposed, what proposals, if any, might actually be enacted by the United States Congress or the various state legislatures and what effect, if any, the proposals might have on our operations. Additionally, such sales may be subject to certain state, and potentially federal, reporting requirements.

Our ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction under the Interstate Commerce Act ("ICA"), and intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. Certain regulations implemented by FERC in recent years and certain pending rulemaking and other proceedings could result in an increase in the cost of transportation service on certain petroleum products pipelines. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other crude oil and condensate producers with which we compete.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to other crude oil and condensate producers with which we compete.

Our SP 49 Pipeline LLC system is subject to regulation by FERC under the ICA, the Energy Policy Act of 1992, and the rules and orders promulgated thereunder. The ICA requires that tariff rates for liquids pipelines, which include both crude oil pipelines and refined products pipelines, be just and reasonable and non-discriminatory. FERC-regulated liquids pipelines, including SP 49 Pipeline LLC, typically use the FERC indexing methodology to change its rates. FERC, however, retained cost-of-service ratemaking, market-based rates and settlement rates as alternatives to the indexing approach that may be used in certain specified circumstances. FERC reviews the index formula every five years. Pursuant to a December 2020 order, and effective July 1, 2021, the annual index adjustment for the five-year period ending June 30, 2026 will equal the producer price index for finished goods for the applicable year plus an adjustment factor of 0.78%. Rehearing of the December 2020 order has been requested, and the requests remain pending before FERC. Pipelines may raise their rates to the rate ceiling level generated by application of the annual index adjustment factor each year; however, a shipper may challenge such increase if the increase in the pipeline's rates was substantially in excess of the actual cost increases incurred by the pipeline during the relevant year. Because the indexing methodology for the next five-year period is tied to an inflation index and is not based on pipeline-specific costs, the indexing methodology could hamper our ability to recover cost increases.

FERC historically has not investigated rates of liquids pipelines on its own initiative when those rates have not been the subject of a protest or complaint by a shipper.

We have an undivided interest in a pipeline owned by CKB Petroleum, Inc. that is subject to FERC jurisdiction under the ICA, but FERC has granted us a temporary waiver of the filing and reporting requirements. This pipeline is still subject to FERC's jurisdiction under the ICA and is still subject to the other requirements of the ICA. If the facts upon which the waiver was granted change materially, we are required to inform FERC, which may result in revocation of the waiver. If conditions change such that the pipeline no longer qualifies for a waiver, we may be subject to regulation by FERC of the rates, terms and conditions of service on the CKB Petroleum, Inc. pipeline, however these burdens generally would not affect us any differently or to any greater or lesser extent than they affect others in our industry with similar pipelines.

FERC also implements the OCSLA pertaining to transportation and pipeline issues, which requires that all pipelines operating on or across the OCS provide nondiscriminatory transportation service. We own and operate pipelines that are located in the OCS and are subject to the non-discrimination requirements in the OCSLA.

Human Capital

As of December 31, 2020, we employ approximately 414 people located primarily in Texas, Louisiana and Mexico. While headcount does not significantly fluctuate throughout the year, in order to align our workforce with the pace of our business, headcount might increase or decrease in response to various factors, including acquisition activity, unscheduled shut-ins or a change in our capital program.

Our human capital measures and objectives focus on several areas, including, but not limited to diversity and inclusion measures, assuring the safety of our employees, employee recruitment and development and offering a fulsome array of employee health and welfare benefits. We consider our employees a key factor in our success and are focused on developing a diverse team of qualified employees and creating an inclusive workplace culture.

Diversity and Inclusion — We believe that creating a work environment where employees feel welcome, supported and valued results in increased employee engagement and reduced turnover. In order to achieve these goals we carefully observe all applicable laws and have adopted and actively enforce policies in our employee handbook and Code of Business Conduct and Ethics that ensure equal employment opportunities for all and prohibit harassment and discrimination of any kind. Our Code of Business Conduct and Ethics requires adherence to the highest standards of personal integrity and assures the protection of human rights. We have a compliance hotline so that employees can report any violation of these policies, anonymously if they wish. In 2020, we created a diversity committee which is in the process of creating diversity and inclusion goals and strategies. We treat each of our employees with the same high level of respect regardless of such employee's age, color, disability, ethnicity, family or marital status, gender identity or expression, language, national origin, physical and mental ability, political affiliation, race, religion, sexual orientation, socio-economic status, veteran status or other characteristics that make such employee unique. As reflected in our Code of Business Conduct and Ethics, we are committed to working in partnership with vendors and other business partners directly linked to our operations that share our commitment to these same principles.

Safety — Prioritizing safety protects our workforce, our stakeholders and the communities in which we operate. We therefore hold ourselves to the highest standards for responsible and reliable performance, striving to achieve safe, effective and efficient operations. We foster a culture of safety by providing employees with in-depth, role-appropriate safety training upon hiring and as part of the continuous development of our employees. Each employee receives annual Talos-specific refresher safety training, and we conduct triweekly field safety meetings with all offshore employees where they hear directly from senior management and discuss safety culture. After any serious incident we reach out to all offshore employees with a lessons learned report following an in-depth incident investigation process and follow-up throughout the year to ensure any resulting changes to safety protocols are implemented. The Company incentivizes employees to focus on conducting operations in accordance with our strict safety standards and encourages employees to immediately report any breach of safety protocol to their supervisor or our compliance hotline. Safety performance is an element of each employee's performance review and 10% of the value of the 2020 short-term incentive award pool was based upon the Company's achievement of safety goals. Additionally, our offshore employees are eligible to receive a quarterly safety bonus, the value of which is contingent upon active observation and recording of safety behaviors (whether good or in need of improvement) and the number of safety or environmental incidents of non-compliance recorded at the employee's facility location during the quarter. Finally, many of our offshore employees participate in our ESG sub-committees so that they can have a voice in corporate-level decisions about ESG matters. Our employees are empowered and obligated by our Chief Executive Officer to exercise the Stop Work Authority ("SWA"). With the SWA, our employees can call an immediate stop to any work for any safety concern without fear of retaliation or intimidation.

Recruitment, Development and Training — We foster an entrepreneurial culture where open communication is encouraged, the views of our employees are heard and the results of their efforts are recognized. This is one of the reasons why every year since our inception, we have earned a ranking as a Top Workplace on the Houston Chronicle Top Workplaces list. We implement an inclusive and dynamic recruiting process that utilizes online recruiting platforms, referrals, internships and professional recruiters. We foster the growth and professional development of our employees through the use of a robust performance review process, which includes the creation of performance development goals and plans to achieve those goals in order to help each employee reach their full potential. We also offer in-house training and reimburse the costs of outside training in further support of developing our employees. In early 2020, we launched a tuition reimbursement policy to support our employees' pursuit of higher education at accredited institutions. We believe this emphasis on development and training has contributed to our 3.1% turnover rate for 2020.

Health and Welfare Benefits — We retain employees by offering competitive wages and generous benefits that are designed to meet the varied and evolving needs of a diverse workforce. We provide employees with the ability to participate in health and welfare plans, including medical, dental, life, accidental death and dismemberment and short-term and long-term disability insurance plans. In response to the COVID – 19 pandemic, we transitioned office-based employees to a work from home schedule and increased safety measures and protocols for those employees choosing to report to the office, such as mandatory temperature checks, limiting third party visitors, encouraging the use of masks and social distancing. For our employees offshore, we increased pre-departure screenings, which included symptom reporting questionnaires, contact tracing, temperature screenings, and in some cases, negative COVID-19 tests. For our offshore facilities, we provided N95 masks and cleaning supplies, performed daily temperature checks and increased response procedures in the event an employee displayed symptoms.

Available Information

We make our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, all amendments to those reports, and all other information filed with or furnished to the SEC available, free of charge, through our website, https://www.talosenergy.com, as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC. The filings are also available by accessing the SEC's website at https://www.sec.gov.

Item 1A. Risk Factors

Certain factors may have a material adverse effect on our business, financial condition, and results of operations. You should consider carefully the risks and uncertainties described below, in addition to other information contained in this Annual Report, including our Consolidated Financial Statements and related notes. The risks and uncertainties described below are not the only ones we face. Additional risks and uncertainties that we are unaware of, or that we currently believe are not material, may also become important factors that adversely affect our business. If any of the following risks actually occur, our business, financial condition, results of operations and future prospects could be materially and adversely affected. In that event, the trading price of our common stock could decline, and you could lose part or all of your investment.

Risks Related to our Business and the Oil and Natural Gas Industry

Oil and natural gas prices are volatile. Sustained periods of low, or further declines in, commodity prices may adversely affect our financial condition and results of operations, cash flows, access to the capital markets and ability to grow.

Our revenues, cash flows, profitability and future rate of growth substantially depend upon the market prices of oil and natural gas. Prices affect our cash flows available for capital expenditures and our ability to access funds under our Bank Credit Facility and through the capital markets. The amount available for borrowing under our Bank Credit Facility is subject to a borrowing base, which is determined by the lenders taking into account our estimated proved reserves and is subject to periodic redeterminations based on pricing models to be determined by the lenders at such time. Further, because we use the full cost method of accounting for our oil and gas operations, we perform a ceiling test each quarter, which is impacted by declining prices. Significant price declines could cause us to take ceiling test write-downs, which would be reflected as non-cash charges against current earnings. See the Risk Factor entitled "Lower oil and natural gas prices and other factors in the future may result in ceiling test write-downs and other impairments of our asset carrying values" for further discussion.

In addition, significant or extended price declines may also adversely affect the amount of oil and natural gas that we can economically produce. A reduction in production and/or the prices we receive for our production could result in a shortfall in our expected cash flows and require us to reduce our capital spending or borrow funds to cover any such shortfall. In April 2020, extreme shortages of transportation and storage capacity caused the NYMEX WTI front month oil futures price to go negative for the first time. We believe negative pricing resulted from the holders of expiring May 2020 oil purchase contracts being unable or unwilling to take physical delivery of crude oil and accordingly forced to make payments to purchasers of such contracts in order to transfer the corresponding purchase obligations. Any of these factors could negatively impact our ability to replace our production and our future rate of growth.

The markets for oil and natural gas have been volatile historically and are likely to remain volatile in the future. For example, during the period January 1, 2018 through December 31, 2020, the daily NYMEX WTI crude oil price per Bbl ranged from a low of $(36.98) to a high of $77.41, and the daily NYMEX Henry Hub natural gas price per MMBtu ranged from a low of $1.33 to a high of $6.24. Subsequent to December 31, 2020, NYMEX WTI crude oil and NYMEX Henry Hub natural gas prices recorded daily lows of $47.47 per Bbl and $2.45 per MMBtu, respectively.

The prices we receive for our oil and natural gas depend upon many factors beyond our control, including, among others:

- changes in the supply of and demand for oil and natural gas;
- market uncertainty;
- level of consumer product demands;
- hurricanes and other adverse weather conditions;
- the impact of applicable market differentials, including those relating to quality, transportation, fees, energy content and regional pricing;
- domestic and foreign governmental actions, regulations and taxes;

- price and availability of alternative fuels;
- political and economic conditions in oil-producing countries, particularly those in the Middle East, Russia, South America and Africa;
- the occurrence or threat of epidemic or pandemic diseases, such as the outbreak of COVID-19, or any government response to such occurrence or threat;
- actions by the OPEC and other state-controlled oil companies relating to oil and natural gas price and production controls;
- U.S. and foreign supply of oil and natural gas;
- price and quantity of oil and natural gas imports and exports;
- the level of global oil and natural gas exploration and production;
- the level of global oil and natural gas inventories;
- localized supply and demand fundamentals and transportation availability;
- capacity of processing, gathering, storage and transportation facilities;
- speculation as to the future price of oil and the speculative trading of oil and natural gas futures contracts;
- price and availability of competitors' supplies of oil and natural gas;
- technological advances affecting energy consumption; and
- overall domestic and foreign economic conditions.

These factors make it very difficult to predict future commodity price movements with any certainty. Substantially all of our oil and natural gas sales are made in the spot market or pursuant to contracts based on spot market prices and are not long-term fixed price contracts. Further, oil prices and natural gas prices do not necessarily fluctuate in direct relation to each other. Because oil, natural gas and NGLs accounted for approximately 67%, 26%, and 7%, respectively, of our estimated proved reserves as of December 31, 2020, and approximately 68%, 24%, and 8%, respectively, of our 2020 production on an MBoe basis, our financial results are sensitive to movements in oil, natural gas and NGL prices.

Our production, revenue and cash flow from operating activities are derived from assets that are concentrated in a single geographic area, making us vulnerable to risks associated with operating in one geographic area.

Our production, revenue and cash flow from operating activities are derived from assets that are concentrated in a single geographic area, the U.S. Gulf of Mexico and in the shallow waters off the coast of Mexico. Unlike other entities that are geographically diversified, we may not have the resources to effectively diversify our operations or benefit from the possible spreading of risks or offsetting of losses. Our lack of diversification may subject us to numerous economic, competitive and regulatory developments, any or all of which may have an adverse impact upon the particular industry in which we operate, and result in our dependency upon a single or limited number of hydrocarbon basins. In addition, the geographic concentration of our properties in the U.S. Gulf of Mexico and in the shallow waters off the coast of Mexico means that some or all of our properties could be affected should the region experience:

- severe weather, such as hurricanes and other adverse weather conditions;
- delays or decreases in production or the availability of equipment, facilities or services;
- delays or decreases in the availability or capacity to transport, gather or process production;
- changes in the status of pipelines that we depend on for transportation of our production to the marketplace;
- extensive governmental regulation (including regulations that may, in certain circumstances, impose strict liability for pollution damage or require posting substantial bonds to address decommissioning and P&A costs) and interruption or termination of operations by governmental authorities based on environmental, safety or other considerations;

- changes in the regulatory environment such as the guidelines issued by the BOEM related to financial assurance requirements to cover decommissioning obligations for operations on the OCS; and/or
- changes imposed as a result of litigation or by a new Presidential Administration or by Congress in the United States that may result in added restrictions and delays or prohibitions in offshore oil and natural gas exploration and production activities, including with respect to permitting, site development or operation in federal waters or hydraulic fracturing.

Because all or a number of our properties could experience many of the same conditions at the same time, these conditions may have a relatively greater impact on our results of operations than they might have on other producers who have properties over a wider geographic area.

Production periods or reserve lives for U.S. Gulf of Mexico properties may subject us to higher reserve replacement needs and may impair our ability to reduce production during periods of low oil and natural gas prices.

Substantially all of our operations are in the U.S. Gulf of Mexico. As a result, our reserve replacement needs from new prospects may be greater than those of other oil and natural gas companies with longer-life reserves in other producing areas. Our future oil and natural gas production is highly dependent upon our level of success in finding or acquiring additional reserves at a unit cost that is sustainable at prevailing commodity prices.

Exploring for, developing or acquiring reserves is capital intensive and uncertain. We may not be able to economically find, develop or acquire additional reserves or make the necessary capital investments if our cash flows from operations decline or external sources of capital become limited or unavailable. Our need to generate revenues to fund ongoing capital commitments or repay debt may limit our ability to slow or shut-in production from producing wells during periods of low prices for oil and natural gas. We cannot assure you that our future exploitation, exploration, development and acquisition activities will result in additional proved reserves or that we will be able to drill productive wells at acceptable costs. Further, current market conditions may adversely impact our ability to obtain financing to fund acquisitions, and further lower the level of activity and depressed values in the oil and natural gas property sales market.

Our actual recovery of reserves may substantially differ from our proved reserve estimates.

Estimates of our proved oil and natural gas reserves and the estimated future net cash flows from such reserves are based upon various assumptions, including assumptions required by the SEC relating to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating oil and natural gas reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir and is therefore inherently imprecise. Additionally, our interpretations of the rules governing the estimation of proved reserves could differ from the interpretation of staff members of regulatory authorities resulting in estimates that could be challenged by these authorities.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will most likely vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of reserves. Our properties may also be susceptible to hydrocarbon drainage from production by other operators on adjacent properties. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

You should not assume that any present value of future net cash flows from our proved reserves represents the market value of our estimated oil and natural gas reserves. We base the estimated discounted future net cash flows from our proved reserves at December 31, 2020 on historical 12-month average prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower. Further, actual future net revenues are affected by factors such as:

- the amount and timing of capital expenditures and decommissioning costs;
- the rate and timing of production;
- changes in governmental legislation, regulations or taxation;
- volume, pricing and duration of our oil and natural gas hedging contracts;

- supply of and demand for oil and natural gas;
- actual prices we receive for oil and natural gas; and
- our actual operating costs in producing oil and natural gas.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties affects the timing of actual future net cash flows from reserves, and thus their actual present value. In addition, the 10% discount factor that we use to calculate the net present value of future net revenues and cash flows may not necessarily be the most appropriate discount factor based on our cost of capital in effect from time to time and the risks associated with our business and the oil and natural gas industry in general.

At December 31, 2020, approximately 22% of our estimated proved reserves (by volume) were undeveloped and approximately 23% were non-producing. Any or all of our PUD or proved developed non-producing reserves may not be ultimately developed or produced. Furthermore, any or all of our undeveloped and developed non-producing reserves may not be ultimately produced during the time periods we plan or at the costs we budget, which could result in the write-off of previously recognized reserves. Recovery of undeveloped reserves generally requires significant capital expenditures and successful drilling or waterflood operations. Our reserve estimates include the assumptions that we incur capital expenditures to develop these undeveloped reserves and the actual costs and results associated with these properties may not be as estimated. Any material inaccuracies in these reserve estimates or underlying assumptions materially affects the quantities and present value of our reserves, which could adversely affect our business, results of operations and financial condition.

Our acreage has to be drilled before lease expirations in order to hold the acreage by production. If commodity prices become depressed for an extended period of time, it might not be economical for us to drill sufficient wells in order to hold acreage, which could result in the expiry of a portion of our acreage, which could have an adverse effect on our business.

Unless production is established as required by the leases covering the undeveloped acres, the leases for such acreage may expire.

Our drilling plans for areas not held by production are subject to change based upon various factors. Many of these factors are beyond our control, including drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals. On the acreage that we do not operate, we have less control over the timing of drilling, and therefore there is additional risk of expirations occurring in those acreages.

The marketability of our production depends mostly upon the availability, proximity and capacity of oil and natural gas gathering systems, pipelines and processing facilities.

The marketability of our production depends upon the availability, proximity, operation and capacity of oil and natural gas gathering systems, pipelines and processing facilities. The lack of availability or capacity of these gathering systems, pipelines and processing facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. The disruption of these gathering systems, pipelines and processing facilities due to maintenance and/or weather could negatively impact our ability to market and deliver our products. Federal, state, and local regulation of oil and natural gas production and transportation, general economic conditions and changes in supply and demand could adversely affect our ability to produce and market our oil and natural gas. If market factors change dramatically, the financial impact could be substantial. The availability of markets and the volatility of product prices are beyond our control and represent a significant risk.

Lower oil and natural gas prices and other factors in the future may result in ceiling test write-downs and other impairments of our asset carrying values.

We use the full cost method of accounting for our oil and gas operations. Accordingly, we capitalize the costs to acquire, explore for and develop oil and natural gas properties. Under the full cost method of accounting, our capitalized costs are limited to a ceiling based on the present value of future net revenues from proved reserves, computed using a discount factor of 10 percent, plus the lower of cost or estimated fair value of unproved oil and natural gas properties not being amortized less the related tax effects. Any costs in excess of the ceiling are recognized as a non-cash "Write-down of oil and natural gas properties" on the Consolidated Statements of Operations and an increase to "Accumulated depreciation, depletion and amortization" on our Consolidated Balance Sheets. A write-down of oil and natural gas properties does not impact cash flows from operating activities, but does reduce net income. The risk that we are required to write-down the carrying value of oil and natural gas properties increases when oil and natural gas prices are low or volatile. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves or our undeveloped property values, or if estimated future development costs increase. Volatility in commodity prices, poor conditions in the global economic markets and other factors could cause us to record additional write-downs of our oil and natural gas properties and other assets in the future, and incur additional charges against future earnings. Any required write-downs or impairments could materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations and financial condition.

If we are forced to shut-in production, we will likely incur greater costs to bring the associated production back online, and will be unable to predict the production levels of such wells once brought back online.

The recent actions of foreign oil producers such as Saudi Arabia and Russia, coupled with the impact on global demand from the COVID-19 pandemic, have materially decreased global crude oil prices and generated a surplus of oil. This significant surplus has created a saturation of storage and caused crude oil storage constraints, which could lead to the shut-in of production of our wells due to lack of sufficient markets or lack of availability and capacity of processing, gathering, storing and transportation systems. If we are forced to shut in production we will likely incur greater costs to bring the associated production back online. Cost increases necessary to bring the associated wells back online may be significant enough that such wells would become uneconomic at low commodity price levels, which may lead to decreases in our proved reserve estimates and potential impairments and associated charges to our earnings. If we are able to bring wells back online, there is no assurance that such wells will be as productive following recommencement as they were prior to being shut-in. Any shut-in or curtailment of the oil, natural gas and NGLs produced from our fields could adversely affect our financial condition and results of operations.

Our business could be negatively affected by security threats, including cybersecurity threats, terrorist attacks and other disruptions.

As an oil and gas producer, we have various security threats, including cybersecurity threats to gain unauthorized access to sensitive information 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 subjects our operations to increased risks that could have a material adverse effect on our business. In particular, the 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 are sufficient to prevent security breaches from occurring. If any of these security breaches were to occur, they could lead to losses of 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 damage our reputation and lead to financial losses from remedial actions, loss of business or potential liability.

The U.S. government has issued warnings that U.S. energy assets may be the future targets of terrorist organizations. These developments subject our operations to increased risks. Any future terrorist attack at our facilities, or those of our purchasers or vendors, could have a material adverse effect on our financial condition and operations.

Events outside of our control, including an epidemic or outbreak of an infectious disease, such as COVID-19, may materially adversely affect our business.

We face risks related to epidemics, outbreaks or other public health events that are outside of our control, and could significantly disrupt our operations and adversely affect our financial condition. The global or national outbreak of an illness or other communicable disease, or any other public health crisis, such as COVID-19, may cause disruptions to our business and operational plans, which may include (i) shortages of employees, (ii) unavailability of contractors or 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, to address an outbreak and (v) restrictions that we and our contractors, subcontractors and our customers impose, including facility shutdowns, to ensure the safety of employees. For example, in response to COVID-19, we have reduced third party expenses and reduced capital expenditures. In addition, the effects of COVID-19 and concerns regarding its global spread could negatively impact the domestic and international demand for crude oil and natural gas, which could contribute to price volatility, impact the price we receive for oil and natural gas and materially and adversely affect the demand for and marketability of our production. The potential impact from COVID-19, both now and in the future, is difficult to predict, and the extent to which it may negatively affect our operating results or the duration of any potential business disruption is uncertain. Any potential impact will depend on future developments and new information that may emerge regarding the COVID-19 infection rate or the efficacy and distribution of COVID-19 vaccines, and the actions taken by authorities to contain it or treat its impact, all of which are beyond our control. These potential impacts, while uncertain, could adversely affect our operating results.

We may not receive payment for a portion of our future production.

We may not receive payment for a portion of our future production. We attempt to diversify our sales and obtain credit protections, such as parent guarantees, from certain of our purchasers. The tightening of credit in the financial markets may make it more difficult for customers to obtain financing and, depending on the degree to which this occurs, there may be a material increase in nonpayment and nonperformance by customers. We are unable to predict what impact the financial difficulties of certain customers may have on our future results of operations and liquidity.

New technologies may cause our current exploration and drilling methods to become obsolete, and we may not be able to keep pace with technological developments in our industry.

The oil and natural gas industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages, and that may in the future, allow them to implement new technologies before we can. We rely heavily on the use of seismic technology to identify low-risk development and exploitation opportunities and to reduce our geological risk. Seismic technology or other technologies that we may implement in the future may become obsolete. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. If we are unable to maintain technological advancements consistent with industry standards, our business, results of operations and financial condition may be materially adversely affected.

We may not be in a position to control the timing of development efforts, the associated costs or the rate of production of the reserves from our non-operated properties.

As we carry out our drilling program, we may not serve as operator of all planned wells. We may have limited ability to exercise influence over the operations of some non-operated properties and their associated costs. Our dependence on the operator and other working interest owners, and our limited ability to influence operations and associated costs of properties operated by others, could prevent the realization of anticipated results in drilling or acquisition activities. The success and timing of development and exploitation activities on properties operated by others depends upon a number of factors that could be largely outside of our control, including:

- the timing and amount of capital expenditures;
- the availability of suitable offshore drilling rigs, drilling equipment, support vessels, production and transportation infrastructure and qualified operating personnel;
- the operator’s expertise and financial resources;

- approval of other participants in drilling wells;
- risk of other non-operator's failure to pay its share of costs, which may require us to pay our proportionate share of the defaulting party's share of costs;
- selection of technology;
- the rate of production of the reserves; and
- the timing and cost of P&A operations.

In addition, with respect to oil and natural gas projects that we do not operate, we have limited influence over operations, including limited control over the maintenance of safety and environmental standards. The operators of those properties may, depending on the terms of the applicable joint operating agreement:

- refuse to initiate exploration or development projects;
- initiate exploration or development projects on a slower or faster schedule than we would prefer;
- delay the pace of exploratory drilling or development; and/or
- drill more wells or build more facilities on a project than we can afford, whether on a cash basis or through financing, which may limit our participation in those projects or limit the percentage of our revenues from those projects.

The occurrence of any of the foregoing events could have a material adverse effect on our anticipated exploration and development activities.

Hedging transactions may limit our potential gains.

In order to manage our exposure to price risks in the marketing of our oil, natural gas and NGLs, we periodically enter into oil, natural gas and NGLs price hedging arrangements with respect to a portion of our expected production. Our Hedging Risk Management Policy provides that we may enter into hedging arrangements covering up to the following maximum percentages of volumes: (i) 90% of the reasonably anticipated quarterly production of oil, natural gas and NGLs of PDP volumes during months January through July and November through December, (ii) 65% of the reasonably anticipated quarterly production of oil, natural gas and NGLs of PDP volumes during months August through October, (iii) 50% of the reasonably anticipated quarterly production of oil, natural gas and NGLs of our proved developed non-producing volumes during months January through July and November through December and (iv) 0% of the reasonably anticipated quarterly production of oil, natural gas and NGLs of its proved developed non-producing volumes during months August through October. These arrangements may include futures contracts on the NYMEX. While intended to reduce the effects of volatile oil and natural gas prices, such transactions, depending on the hedging instrument used, may limit our potential gains if oil and natural gas prices were to rise substantially over the price established by the hedge. In addition, such transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected or is shut-in for extended periods due to hurricanes or other factors;
- there is a widening of price differentials between delivery points for our production and the delivery point to be assumed in the hedge arrangement;
- the counterparties to our futures contracts fails to perform the contracts;
- a sudden, unexpected event materially impacts oil or natural gas prices; or
- we are unable to market our production in a manner contemplated when entering into the hedge contract.

Our outstanding commodity derivative instruments are with certain lenders or affiliates of the lenders under our Bank Credit Facility. Our derivative agreements with the lenders are secured by the security documents executed by the parties under the Bank Credit Facility. Future collateral requirements for our commodity hedging activities are uncertain and depend on the arrangements we negotiate with the counterparty and the volatility of oil and natural gas prices and market conditions.

Our operations may incur substantial liabilities to comply with environmental laws and regulations as well as legal requirements applicable to marine mammals and endangered and threatened species.

Our oil and natural gas operations in the United States and Mexico are subject to stringent federal, state and/or local laws and regulations relating to the release or disposal of materials into the environment or otherwise relating to environmental protection. These laws and regulations require the acquisition of a permit or other approval before drilling or other regulated activity commences; restrict the types, quantities and concentration of substances that can be released into the environment in connection with drilling and production activities; limit or prohibit exploration or drilling activities on certain lands lying within protected areas or that may affect certain wildlife, including marine species and endangered and threatened species and impose substantial liabilities for pollution resulting from our operations. Additionally, the threat of climate change continues to attract considerable attention in the United States and in foreign countries, and orders have already been issued under the Biden Administration to combat climate change and GHG emissions. See Part I, Item 1. Business — Government Regulation — *Environmental and Occupational Safety and Health Regulations* for more discussion on environmental, climate change and worker safety matters. One or more of these developments that impact our oil and natural gas exploration and production activities on the OCS could have a material adverse effect on our business, results of operations and financial condition.

Additional drilling laws, regulations, executive orders and other regulatory initiatives that restrict, delay or prohibit oil and natural gas exploration, development and production activities or locations where such activities may occur could have a material adverse effect on our business, financial condition or results of operations.

The Biden Administration has issued orders temporarily suspending the delegation of authority to the bureaus and agencies of the DOI to approve any new permitting of oil and natural gas activities on federal lands and waters, including the OCS for a period of 60 days dating from January 20, 2021, and has further suspended new leasing for oil and natural gas exploration and production upon those federal lands and waters pending review and reconsideration of federal oil and gas permitting and leasing practices. The Biden Administration could also pursue additional orders or legislation or regulatory initiatives regarding leasing, permitting or drilling that may result in more stringent or costly restrictions, delays or cancellations to our operations as well as those of similarly situated offshore energy companies on the OCS.

Over the past decade, BSEE and BOEM, primarily under the Obama Administration, have imposed new and more stringent permitting procedures and regulatory safety and performance requirements for new wells to be drilled in federal waters. In recent years, there have been actions by BSEE or BOEM under the Trump Administration seeking to mitigate or delay certain of those more rigorous standards; however, with the Biden Administration having entered office in January 2021, it is possible that the new administration will reconsider rules and regulatory initiatives implemented under the Trump Administration and may replace them with more stringent requirements. Compliance with any added and more stringent regulatory requirements and existing environmental and spill regulations, together with uncertainties or inconsistencies in decisions and rulings by governmental agencies and delays in the processing and approval of drilling permits and exploration, development, oil spill response and decommissioning plans result in difficult and more costly actions and adversely affect or delay new drilling and ongoing development efforts. Moreover, these governmental agencies under the new Biden Administration could continue evaluating aspects of safety and operational performance in the U. S. Gulf of Mexico that may result in new, more restrictive requirements.

These regulatory actions, or any new laws, executive orders, regulations or other legal initiatives, that impose increased costs or more stringent operational standards could delay or disrupt our operations, result in increased supplemental bonding and associated costs, and limit activities in certain areas, or cause us to incur penalties, fines, or shut-in production at one or more of our facilities or result in suspension or cancellation of leases. Also, if material spill incidents were to occur in the future, the United States or other countries where such an event may occur could elect to issue directives to temporarily cease drilling activities and, in any event, may from time to time issue further safety and environmental laws and regulations regarding offshore oil and natural gas exploration and development, any of which could have a material adverse effect on our business. We cannot predict with any certainty the full impact of any new laws or regulations on our drilling operations or on the cost or availability of insurance to cover some or all of the risks associated with such operations.

See Part I, Item 1. Business — Government Regulation — *OCS Regulation* for more discussion on orders and regulatory initiatives impacting the oil and natural gas industry on the OCS.

We may be unable to provide the financial assurances in the amounts and under the time periods required by the BOEM if it submits future demands to cover our decommissioning obligations. If in the future the BOEM issues orders to provide additional financial assurances and we fail to comply with such future orders, the BOEM could elect to take actions that would materially adversely impact our operations and our properties, including commencing proceedings to suspend our operations or cancel our federal offshore leases.

The BOEM requires that lessees demonstrate financial strength and reliability according to its regulations or provide acceptable financial assurances to assure satisfaction of lease obligations, including decommissioning activities on the OCS. As of the filing date of this Annual Report, we have no outstanding BOEM orders for financial assurance obligations. In 2016, the BOEM under the Obama Administration had sought to implement more stringent and costly standards under the existing federal financial assurance requirements through issuance and implementation of the 2016 NTL, but former President Trump's Administration first paused, and then in 2020 rescinded, the implementation of this NTL while the BOEM and the BSEE issued a jointly proposed rulemaking in October 2020 in which BOEM proposed amendments to its financial assurance program. However, with President Biden having taken office in January 2021, it is possible that the new Administration will reconsider regulatory actions undertaken by the former Administration with respect to financial assurance requirements, including rescission of the 2016 NTL and publication of the October 2020 proposed rule, and may adopt and implement more stringent supplemental bonding requirements.

Following the effectiveness of the 2016 NTL, we received orders from the BOEM in late 2016 directing us to provide additional financial assurance in material amounts relating to our OCS properties. We entered into discussions with the BOEM regarding the requested additional financial security and submitted a proposed tailored plan for the posting of additional financial security to the agency for review. However, as noted, the BOEM under the Trump Administration first delayed, and then rescinded the 2016 NTL; consequently, to date, the BOEM has taken no action with respect to our previously submitted proposed tailored plan.

Under the Biden Administration, the BOEM, could in the future make new demands for additional financial assurances in material amounts relating to the decommissioning of our OCS properties. The BOEM may reject our proposals to satisfy any such additional financial assurance coverage and make demands that exceed our capabilities.

If we fail to comply with the current or future orders of the BOEM to provide additional surety bonds or other financial assurances, the BOEM could commence enforcement proceedings or take other remedial action, including assessing civil penalties, suspending operations or production, or initiating procedures to cancel leases, which, if upheld, would have a material adverse effect on our business, properties, results of operations and financial condition.

In addition, if the 2016 NTL was re-issued, or a similarly stringent NTL was issued under the Biden Administration, the likely result could include the loss of supplemental bonding waivers for a large number of operators on the OCS, which could in turn force these operators to seek additional surety bonds and could, consequently, challenge the surety bond market's capacity for providing such additional financial assurance. Operators who have already leveraged their assets as a result of the declining oil market could face difficulty obtaining surety bonds because of concerns the surety companies may have about the priority of their lien on the operator's collateral. Moreover, depressed oil prices could result in sureties seeking additional collateral to support existing bonds, such as cash or letters of credit, and we cannot provide assurance that we will be able to satisfy collateral demands for future bonds to comply with supplemental bonding requirements of the BOEM. If we are required to provide collateral in the form of cash or letters of credit, our liquidity position could 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. All of these factors may make it more difficult for us to obtain the financial assurances required by the BOEM to conduct operations on the OCS. These and other changes to BOEM bonding and financial assurance requirements could result in increased costs on our operations and consequently have a material adverse effect on our business and results of operations.

Our oil and gas operations are subject to various international, foreign and U.S. federal, state and local governmental regulations that materially affect our operations.

Our oil and gas operations are subject to various international, foreign and U.S. federal, state and local laws and regulations. These laws and regulations may be changed in response to economic or political conditions. Regulated matters include: permits for exploration, development and production operations; limitations on our drilling activities in environmentally sensitive areas, such as marine habitats, and restrictions on the way we can discharge materials into the environment; bonds or other financial responsibility requirements to cover drilling contingencies, well P&A and other decommissioning costs; reports concerning operations, the spacing of wells and unitization and pooling of properties; regulations regarding the rate, terms and conditions of transportation service or the price, terms, and conditions related to the purchase and sale of oil and natural gas; and taxation. Failure to comply with these laws and regulations can result in the assessment of administrative, civil or criminal penalties, the issuance of remedial obligations and the imposition of injunctions limiting or prohibiting certain of our operations. In addition, because we hold federal leases, the federal government requires that we comply with numerous additional regulations applicable to government contractors.

In July 2017, we, along with partners Sierra and Premier, reported the discovery of a significant reservoir of crude oil in the Sureste basin offshore Mexico through the Zama-1 well. Data from the Zama-1 well indicates that it is possible the deposit could be part of a field that extends into an exploration block in which the state entity Pemex holds exploration and development rights.

The Ministry of Energy of Mexico has promulgated guidelines to establish procedures for conducting the unitization of shared reservoirs and approving the terms and conditions of unitization and unit operating agreements, as well as the authority to direct parties holding rights in a potentially shared reservoir to appraise and potentially form a unit for development of such reservoir.

Even with the final regulations in place, there are still some uncertainties regarding the unitization process, including the selection of a unit operator and the exact length of time that it will take to obtain approvals of any unit agreements. Any unit operating agreement eventually agreed to by the relevant parties or any unit order issued by a governmental entity in Mexico could be adverse to us and affect the value that we are able to recognize from the reservoir discovery, including but not limited to an agreement or unit order that would require us to allow a third party to develop and produce the crude oil reservoir identified through the Zama-1 well.

In September 2015, we, together with our consortium partners executed a PSC with the CNH for each of Blocks 2 and 7 of Round 1. The PSCs require that the consortium execute a minimum work program expressed in work units during a four-year exploration period. Effective January 23, 2018, the activities already performed on Block 7 have satisfied the minimum work program on Block 7. Effective September 4, 2019, the activities already performed on Block 2 have satisfied the minimum work program on Block 2. Effective December 2, 2020, the activities already performed on Block 31 have satisfied the minimum work program on Block 31.

Our operations may be adversely affected by political and economic circumstances in the countries in which we operate.

Our oil and gas exploration, development and production activities are subject to political and economic uncertainties (including but not limited to changes, sometimes frequent or marked, in energy policies or the personnel administering them), expropriation of property, cancellation or modification of contract rights, changes in laws and policies governing operations of foreign-based companies, unilateral renegotiation of contracts by governmental entities, redefinition of international boundaries or boundary disputes, foreign exchange restrictions, currency fluctuations, royalty and tax increases and other risks arising out of governmental sovereignty over the areas in which our operations are conducted, as well as risks of loss due to acts of terrorism, piracy, disease, illegal cartel activities and other political risks, including tension and confrontations among political parties. Some of these risks may be higher in the developing countries in which we conduct our activities, namely, Mexico. Mexico's most recent presidential election was held in July 2018. Presidential reelection is not permitted in Mexico. President Andrés Manuel López Obrador, took office on December 1, 2018, and his political party, Movimiento Regeneración Nacional has a majority in both houses of Mexico's congress. Mr. Lopez Obrador, and certain members of his cabinet have, in the past, made statements that would call into question the degree of support their administration will have for Mexico's energy reforms. However, at this time we cannot predict what changes (if any) will result from this change in administration. Political events in Mexico could adversely affect economic conditions and/or the oil and gas industry and, by extension, our results of operations and financial position.

We may experience significant shut-ins and losses of production due to the effects of hurricanes in the U.S. Gulf of Mexico and in the shallow waters off the coast of Mexico.

Our production is primarily associated with our properties in the U.S. Gulf of Mexico and in the shallow waters off the coast of Mexico. Accordingly, if the level of production from these properties substantially declines, it could have a material adverse effect on our overall production level and our revenue. We are particularly vulnerable to significant risk from hurricanes and tropical storms in the U.S. Gulf of Mexico. We are unable to predict what impact future hurricanes and tropical storms might have on our future results of operations and production.

We are not insured against all of the operating risks to which our business is exposed.

In accordance with industry practice, we maintain insurance against some, but not all, of the operating risks to which our business is exposed. We insure some, but not all, of our properties from operational loss-related events. We have insurance policies that include coverage for general liability, physical damage to our oil and gas properties, operational control of well, named U.S. Gulf of Mexico windstorm, oil pollution, construction all risk, workers' compensation and employers' liability and other coverage. Our insurance coverage includes deductibles that have to be met prior to recovery, as well as sub-limits or self-insurance. Additionally, our insurance is subject to exclusions and limitations, and there is no assurance that such coverage will adequately protect us against liability from all potential consequences, damages or losses.

We have general liability insurance coverage with an annual aggregate limit of $500 million. We selectively purchase physical damage insurance coverage for our pipelines, platforms, facilities and umbilicals for losses resulting from named windstorms and operational activities.

Our operational control of well coverage is expected to provide limits that vary by well location and depth and range from a combined single limit of $25 million to $500 million per occurrence. Exploratory deepwater wells have a coverage limit of up to $500 million per occurrence. Additionally, we maintain up to $150 million in oil pollution liability coverage. Our operational control of well and physical damage policy limits is scaled proportionately to our working interests. Our general liability program utilizes a combination of assured's interest and scalable limits. All of our policies described above are subject to deductibles, sub-limits, or self-insurance. Under our service agreements, including drilling contracts, generally we are indemnified for injuries and death of the service provider's employees as well as contractors and subcontractors hired by the service provider, subject to the application of various states' laws.

An operational or hurricane or other adverse weather-related event may cause damage or liability in excess of our coverage that might severely impact our financial position. We may be liable for damages from an event relating to a project in which we own a non-operating working interest. Such events may also cause a significant interruption to our business, which might also severely impact our financial position. We may experience production interruptions for which we do not have production interruption insurance.

We reevaluate the purchase of insurance, policy limits and terms annually. Future insurance coverage for our industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that we believe are economically acceptable. No assurance can be given that we will be able to maintain insurance in the future at rates that we consider reasonable, and we may elect to maintain minimal or no insurance coverage. We may not be able to secure additional insurance or bonding that might be required by new governmental regulations. This may cause us to restrict our operations in the U.S. Gulf of Mexico, which might severely impact our financial position. The occurrence of a significant event, not fully insured against, could have a material adverse effect on our financial condition and results of operations.

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

SEC rules require that, subject to limited exceptions, PUD reserves may only be booked if they relate to wells scheduled to be drilled within five years after the date of booking. This requirement may limit our ability to book additional PUD reserves as we pursue our drilling program. Moreover, we may be required to write down our PUD reserves if we do not drill those wells within the required five-year timeframe.

Our actual production could differ materially from our forecasts.

From time to time, we may provide forecasts of expected quantities of future oil and gas production. These forecasts are based on a number of estimates, including expectations of production from existing wells. In addition, our forecasts may assume that none of the risks associated with our oil and natural gas operations summarized in this section would occur, such as facility or equipment malfunctions, adverse weather effects or significant declines in commodity prices or material increases in costs, which could make certain production uneconomical.

Our operations are subject to numerous risks of oil and natural gas drilling and production activities.

Oil and gas drilling and production activities are subject to numerous risks, including the risk that no commercially productive oil or natural gas reserves are found. The cost of drilling and completing wells is often uncertain. To the extent we drill additional wells in the U.S. Gulf of Mexico deepwater and/or in the Gulf Coast deep gas, our drilling activities increase capital cost. In addition, the geological complexity of the areas in which we have oil and natural gas operations make it more difficult for us to sustain the historical rates of drilling success. Oil and natural gas drilling and production activities may be shortened, delayed or cancelled as a result of a variety of factors, many of which are beyond our control. These factors include:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- hurricanes and other adverse weather conditions;
- shortages in experienced labor; and
- shortages or delays in the delivery of equipment.

The prevailing prices of oil and natural gas also affect the cost of and the demand for drilling rigs, production equipment and related services. We cannot assure you that the wells we drill will be productive or that we will recover all or any portion of our investment. Drilling for oil and natural gas may be unprofitable. Drilling activities can result in dry holes and wells that are productive but do not produce sufficient cash flows to recoup drilling costs.

Our industry experiences numerous operating risks.

The exploration, development and production of oil and gas properties involves a variety of operating risks, including the risk of fire, explosions, blowouts, pipe failure, abnormally pressured formations and environmental hazards. Environmental hazards include oil spills, gas leaks, pipeline ruptures or discharges of toxic gases. We are also involved in completion operations that utilize hydraulic fracturing, which may potentially present additional operational and environmental risks. Additionally, our offshore operations are subject to the additional hazards of marine operations, such as capsizing, collisions and adverse weather and sea conditions, including the effects of hurricanes.

In addition, an oil spill on or related to our properties and operations could expose us to joint and several strict liability, without regard to fault, under applicable law for containment and oil removal costs and a variety of public and private damages, including, but not limited to, the costs of responding to 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 could be liable for costs and damages, which costs and damages could be material to our results of operations and financial position.

Our business is also subject to the risks and uncertainties normally associated with the exploration for and development and production of oil and natural gas that are beyond our control, including uncertainties as to the presence, size and recoverability of hydrocarbons. We may not encounter commercially productive oil and natural gas reservoirs. We may not recover all or any portion of our investment in new wells. The presence of unanticipated pressures or irregularities in formations, miscalculations or accidents may cause our drilling activities to be unsuccessful and/or result in a total loss of our investment, which could have a material adverse effect on our financial condition, results of operations and cash flows. In addition, we may be uncertain as to the future cost or timing of drilling, completing and operating wells.

We have an interest in deepwater fields and may attempt to pursue additional operational activity in the future and acquire additional fields and leases in the deepwaters of the U.S. Gulf of Mexico. Exploration for oil or natural gas in the deepwater of the U.S. Gulf of Mexico generally involves greater operational and financial risks than exploration in the shallower waters of the U.S. Gulf of Mexico conventional shelf. Deepwater drilling generally requires more time and more advanced drilling technologies, involving a higher risk of technological failure and usually higher drilling costs. For example, the drilling of deepwater wells requires specific types of drilling rigs with significantly higher day rates and limited availability as compared to the rigs used in shallower water. Deepwater wells often use subsea completion techniques with subsea trees tied back to host production facilities with flow lines. The installation of these subsea trees and flow lines requires substantial time and the use of advanced remote installation mechanics. These operations may encounter mechanical difficulties and equipment failures that could result in cost overruns. Furthermore, the deepwater operations generally lack the physical and oilfield service infrastructure present in the shallower waters of the U.S. Gulf of Mexico conventional shelf. As a result, a considerable amount of time may elapse between a deepwater discovery and the marketing of the associated oil or natural gas, increasing both the financial and operational risk involved with these operations. Because of the lack and high cost of infrastructure, some reserve discoveries in the deepwater may never be produced economically.

If any of these industry operating risks occur, we could have substantial losses. Substantial losses may be caused by injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties, suspension of operations and production and repairs to resume operations. Any of these industry operating risks could have a material adverse effect on our business, results of operations and financial condition.

Competition within our industry may adversely affect our operations.

Competition within our industry is intense, particularly with respect to the acquisition of producing properties and undeveloped acreage. We compete with major oil and gas companies and other independent producers of varying sizes, all of which are engaged in the acquisition of properties and the exploration and development of such properties. Many of our competitors have financial resources and exploration and development budgets that are substantially greater than our budget, which may adversely affect our ability to compete. If other companies relocate to the U.S. Gulf of Mexico region, levels of competition may increase and our business could be adversely affected. In the exploration and production business, some of the larger integrated companies may be better able than we are to respond to industry changes including price fluctuations, oil and gas demand, political change and government regulations.

We actively compete with other companies when acquiring new leases or oil and gas properties. For example, new leases acquired from the BOEM are acquired through a "sealed bid" process and are generally awarded to the highest bidder. These additional resources can be particularly important in reviewing prospects and purchasing properties. The competitors may also have a greater ability to continue drilling activities during periods of low oil and gas prices, such as the current decline in oil prices, and to absorb the burden of current and future governmental regulations and taxation. Competitors may be able to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Competitors may also be able to pay more for productive oil and gas properties and exploratory prospects than we are able or willing to pay. Further, our competitors may be able to expend greater resources on the existing and changing technologies that we believe impacts attaining success in the industry. If we are unable to compete successfully in these areas in the future, our future revenues and growth may be diminished or restricted.

The loss of our larger customers could materially reduce our revenue and materially adversely affect our business, financial condition and results of operations.

We have a limited number of customers that provide a substantial portion of our revenue. The loss of our larger customers, including Shell Trading (US) Company, could adversely affect our current and future revenue, and could have a material adverse effect on our business, financial condition and results of operations.

The loss of key personnel could adversely affect our ability to operate.

Our industry has lost a significant number of experienced professionals over the years due to its cyclical nature, which is attributable, among other reasons, to the volatility in commodity prices. Our operations are dependent upon key management and technical personnel. We cannot assure you that individuals will remain with us for the immediate or foreseeable future. The unexpected loss of the services of one or more of these individuals could have an adverse effect on us and our operations.

In addition, our exploration, production and decommissioning activities require personnel with specialized skills and experience. As a result, our ability to remain productive and profitable depends upon our ability to employ and retain skilled workers. Our ability to expand operations depends in part on our ability to increase the size of our skilled labor force, including geologists and geophysicists, field operations managers and engineers, to handle all aspects of our exploration, production and decommissioning activities. The demand for skilled workers in our industry is high, and the supply is limited. A significant increase in the wages paid by competing employers or the unionization of our U.S. Gulf of Mexico employees could result in a reduction of our labor force, increases in the wage rates that we will have to pay, or both. If either of these events were to occur, our capacity and profitability could be diminished and our growth potential could be impaired.

We have operations in multiple jurisdictions, including jurisdictions in which the tax laws, their interpretation or their administration may change. As a result, our tax obligations and related filings are complex and subject to change, and our after-tax profitability could be lower than anticipated. Additionally, future tax legislative or regulatory changes in the United States, Mexico or any other jurisdiction in which we operate or have subsidiaries could result in changes to the taxation of our income and operations, which could also adversely impact our after-tax profitability.

We are subject to income, withholding and other taxes in the United States on a worldwide basis and in numerous state, local and foreign jurisdictions with respect to our income, operations and subsidiaries in those jurisdictions. Our after-tax profitability could be affected by numerous factors, including the availability of tax credits, exemptions, refunds (including refunds of value added taxes) and other benefits to reduce our tax liabilities, changes in the relative amount of our earnings subject to tax in the various jurisdictions in which we operate or have subsidiaries, the potential expansion of our business into or otherwise becoming subject to tax in additional jurisdictions, changes to our existing business structure and operations, the extent of our intercompany transactions and the extent to which taxing authorities in the relevant jurisdictions respect those intercompany transactions.

Our after-tax profitability may also be affected by changes in the relevant tax laws and tax rates, regulations, administrative practices and principles, judicial decisions, and interpretations, in each case, possibly with retroactive effect. In past years, federal and state level legislation in the United States has been proposed that would, if enacted into law, make significant changes to tax laws, including to certain key U.S. federal and state income tax provisions currently available to oil and natural gas exploration and development companies. Additionally, the Multilateral Convention to Implement Tax Treaty Related Measures to Prevent Base Erosion and Profit Shifting (the "Multilateral Instrument") has entered into force among the jurisdictions that have ratified it, although the United States has not yet become a signatory to the Multilateral Instrument. Such proposed legislative changes and ratification of the Multilateral Instrument in the jurisdictions in which we operate could result in further changes to our global taxation. Additionally, Mexico has enacted tax reform legislation, and a majority of the provisions became effective on January 1, 2020. These tax reforms provided for new and complex provisions that significantly change how the United States and Mexico tax entities and operations, and these provisions are subject to further legislative change and administrative guidance and interpretation, all of which may differ from our interpretation. Future tax legislative or regulatory changes in the United States, Mexico or in any other jurisdictions in which we operate now or in the future could also adversely impact our after-tax profitability.

Changes in the method of determining the London Interbank Offered Rate ("LIBOR") or the replacement of LIBOR with an alternative reference rate may adversely affect interest rates.

On July 27, 2017, the Financial Conduct Authority ("FCA") in the United Kingdom announced that it would phase out LIBOR as a benchmark by the end of 2021. It is unclear whether new methods of calculating LIBOR will be established such that it continues to exist after 2021 or whether different benchmark rates used to price indebtedness will develop. In the future, we may need to renegotiate the Bank Credit Facility or incur other indebtedness, and the phase-out of LIBOR may negatively impact the terms of such indebtedness. In addition, the overall financial market may be disrupted as a result of the phase-out or replacement of LIBOR. Disruption in the financial market could have a material adverse effect on our financial position, results of operations and liquidity.

Our operations may incur substantial liabilities to comply with environmental laws and regulations as well as legal requirements applicable to marine mammals and endangered and threatened species.

Our oil and natural gas operations are subject to stringent federal, state, local and foreign laws and regulations relating to the release or disposal of materials into the environment or otherwise relating to environmental protection. These laws and regulations:

- require the acquisition of a permit or other approval before drilling or other regulated activity commences;
- restrict the types, quantities and concentration of substances that can be released into the environment in connection with drilling and production activities;
- limit or prohibit exploration or drilling activities on certain lands lying within protected areas or that may affect certain marine species and endangered and threatened species; and
- impose substantial liabilities for pollution resulting from our operations.
- failure to comply with these laws and regulations may result in:

- the assessment of administrative, civil and criminal penalties;
- loss of our leases;
- incurrence of investigatory, remedial or corrective obligations; and
- the imposition of injunctive relief, which could prohibit, limit or restrict our operations in a particular area.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our industry in general and on our own results of operations, competitive position or financial condition. Under these environmental laws and regulations, we could incur strict joint and several liability for the removal or remediation of previously released materials or contamination, regardless of whether we were responsible for the release or contamination and regardless of whether our operations met previous standards in the industry at the time they were conducted. Our permits require that we report any incidents that cause or could cause environmental damages.

New laws and regulations, amendment of existing laws and regulations, reinterpretation of legal requirements or increased governmental enforcement could significantly increase our capital expenditures and operating costs or could result in delays, limitations or cancelations to our exploration and production activities, which could have an adverse effect on our financial condition, results of operations, or cash flows. See Business – Environmental and Occupational Safety and Health Regulations under Part I, Item 1 of this Annual Report for a more detailed description of our environmental, marine species, and endangered and threatened species legal requirements.

A significant portion of our production, revenue and cash flow is concentrated in our Phoenix Field and our Pompano Field. Because of this concentration, any production problems, impacts of adverse weather or inaccuracies in reserve estimates could have a material adverse impact on our business.

For the year ended December 31, 2020, approximately 25% and 17% of our production and 28% and 20% of our oil, natural gas and NGL revenue was attributable to our Phoenix Field and our Pompano Field, respectively, both of which are located in the federal waters offshore in the U.S. Gulf of Mexico. This concentration in these fields means that any impact on our production from these fields, whether because of mechanical problems, adverse weather, well containment activities, changes in the regulatory environment or otherwise, could have a material effect on our business. We produce the Phoenix Field through the HP-I, a dynamically positioned floating production facility that is operated by Helix. The HP-I interconnects the Phoenix Field through a production buoy that can be disconnected if the HP-I cannot maintain its position on station, such as in the event of a mechanical problem with the dynamic positioning system or the approach of a hurricane. Because the HP-I may have to be disconnected from the Phoenix Field if circumstances require, our production from the Phoenix Field may be subject to more frequent interruptions than if the Phoenix Field was produced by a more conventional platform. We are also required to disconnect and dry-dock the HP-I every two to three years for inspection as required by the United States Coast Guard, during which time we are unable to produce the Phoenix Field. During the year ended December 31, 2019, Helix dry-docked the HP-I. After conducting sea trials, production resumed in late March 2019, resulting in a total shut-in period of 57 days.

The HP-I is part of the Helix Well Containment Group ("HWCG"), which is a consortium that is available to respond to any deepwater well control event, such as the Macondo well oil spill. If such an event were to occur and the HWCG was to be utilized for well control, the HP-I, which is the vessel that would be used to respond to the deepwater well control event, would be required to disconnect from the Phoenix Field until such time as the well control event was resolved and the HP-I could return to the Phoenix Field. During such time period, we would not be able to produce the Phoenix Field. In the event the HP-I has to disconnect from the Phoenix Field, our production, revenue and cash flow could be adversely affected, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

In addition, all of our production from the Phoenix Field flows through the Green Canyon 19 connection facility operated by Shell GOM Pipeline Company LLC. To the extent Shell GOM Pipeline Company LLC temporarily shuts in its Green Canyon 19 connection facility, whether for maintenance or otherwise, we would not be able to produce the Phoenix Field during this period of time, which may have a material adverse effect on our business, financial condition, results of operations and cash flows.

If the actual reserves associated with the Phoenix Field are less than our estimated reserves, such a reduction of reserves could have a material adverse effect on our business, financial condition, results of operations and cash flows.

In addition, all of our production from the Pompano Field flows through the Pompano Pipeline System operated by Crimson Gulf LLC. To the extent Crimson Gulf LLC temporarily shuts in the Pompano Pipeline System, whether for maintenance or otherwise, we would not be able to produce the Pompano Field during this period of time, which may have a material adverse effect on our business, financial condition, results of operations and cash flows.

If the actual reserves associated with the Pompano Field are less than our estimated reserves, such a reduction of reserves could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our Mexican operations are subject to certain offshore regulatory and environmental laws and regulations promulgated by Mexico.

Our operations on oil and natural gas blocks in shallow waters off the coast of Mexico's Veracruz and Tabasco states and in other Mexican offshore areas where we are assessing other exploration opportunities, are subject to regulation by the SENER, the CNH and other Mexican regulatory bodies. The CNH is responsible for, among other things, overseeing the tender procedures for awarding contracts for the exploration and production of oil and natural gas in Mexican waters, managing and supervising contracts that have been awarded and approving exploration and production plans. The PSCs that we and our consortium partners have entered into for the development of these acreages contain terms that impose on us the duty to comply with various laws and regulations. These laws and regulations govern, among other things, the exploration and exploitation of hydrocarbons (including certain national content requirements), the treatment, conveyance, marketing, transport and storage of petroleum, requirements for industrial safety, operational security and facility decommissioning. Failure to comply can result in the imposition of monetary penalties, revocation of permits, rescission of the relevant PSC, suspension of operations and ordered decommissioning of offshore facilities and systems. The laws and regulations governing activities in the Mexican energy sector are relatively new, having been significantly reformed in 2013, and the legal regulatory framework continues to evolve as SENER, the CNH and other Mexican regulatory bodies issue new regulations and guidance. Such regulations are subject to change, and it is possible that SENER, the CNH or other Mexican regulatory bodies may impose new or revised requirements that could increase our operating costs and/or capital expenditures for operations in Mexican offshore waters.

In addition, our operations on oil and natural gas blocks in shallow waters off the coast of Mexico's Veracruz and Tabasco states and in other Mexican offshore areas where we are assessing other exploration opportunities, are subject to regulation by the ASEA. We must obtain ASEA-issued permits and comply with ASEA regulations governing hydrocarbon activities, including requirements for environmental impact and risk assessments, industrial safety, waste management, water and air emissions, operational security and facility decommissioning. Failure to comply with applicable laws and regulations can result in the imposition of monetary penalties, revocation of permits, suspension of operations and ordered decommissioning of offshore facilities and systems. The laws and regulations governing the protection of health, safety and the environment from activities in the Mexican energy sector are relatively new, having been significantly reformed in 2013 and 2014, and the legal regulatory framework continues to evolve as ASEA and other Mexican regulatory bodies issue new regulations and guidance. Such regulations are subject to change, and it is possible that ASEA or other Mexican regulatory bodies may impose new or revised requirements that could increase our operating costs and/or capital expenditures for operations in Mexican offshore waters. For example, in January 2019, the ASEA published the "General Administrative Provisions on the Guidelines for the Design, Construction, Pre-start, Maintenance, Closing, Dismantling and Abandonment of the Facilities and Transfer Operations associated with the Transportation and/or Distribution of Hydrocarbons and/or Oil Products activities, by means other than Pipelines." These legal provisions apply to permit holders in charge of the transportation or distribution of hydrocarbons and oil products by means other than pipelines, such as tank trucks, tank vessels and/or by railroad, in connection with the transfer, racking, loading, discharge, reception or delivery of such hydrocarbons and oil products. The permit holders must comply with requirements relating to insurance, facility construction and design, law compliance, and risk analysis scenarios.

Under the PSCs, we are also jointly and severally liable for the performance of all obligations under the PSCs, including exploration, appraisal, extraction and abandonment activities and compliance with all environmental regulations, and failure to perform such obligations could result in contractual rescission of the PSCs.

Three-dimensional seismic interpretation does not guarantee that hydrocarbons are present or if present, produce in economic quantities.

We rely on 3D seismic studies to assist us with assessing prospective drilling opportunities on our properties, as well as on properties that we may acquire. Such seismic studies are merely an interpretive tool and do not necessarily guarantee that hydrocarbons are present or, if present, produce in economic quantities, and seismic indications of hydrocarbon saturation are generally not reliable indicators of productive reservoir rock. These limitations of 3D seismic data may impact our drilling and operational results, and consequently our financial condition.

We may be exposed to liabilities under the U.S. Foreign Corrupt Practices Act (the "FCPA").

We are subject to the FCPA and other laws that prohibit improper payments or offers of payments to foreign governments and their officials and political parties for the purpose of obtaining or retaining business. We may do business in the future in countries and regions in which we may face, directly or indirectly, corrupt demands by officials, tribal or insurgent organizations or private entities. Thus, we face the risk of unauthorized payments or offers of payments by one of our employees or consultants, given that these parties may not always be subject to our control. Our existing safeguards and any future improvements may prove to be less than effective, and our employees and consultants may engage in conduct for which we might be held responsible.

Under the PSCs with the CNH, we work as a consortium with our partners. Violations of the FCPA, by any consortium partner, may result in severe criminal or civil sanctions, and we may be subject to other liabilities, which could negatively affect our business, operating results and financial condition. In addition, the CNH has the authority to rescind the PSCs if these violations occur.

Our business depends on access to oil and natural gas processing, gathering and transportation systems and facilities.

The marketability of our oil and natural gas production depends in large part on the operation, availability, proximity, capacity and expansion of processing, gathering and transportation facilities owned by third parties. We can provide no assurance that sufficient processing, gathering and/or transportation capacity exists or that we will be able to obtain sufficient processing, gathering and/or transportation capacity on economic terms. A lack of available capacity on processing, gathering and transportation facilities or delays in their planned expansions could result in the shut-in of producing wells or the delay or discontinuance of drilling plans for properties. A lack of availability of these facilities for an extended period of time could negatively impact our revenues. In addition, we enter into contracts for firm transportation, and any failure to renew those contracts on the same or better commercial terms could increase our costs and our exposure to the risks described above. In addition, the rates charged for processing, gathering and transportation services may increase over time.

Our operations are subject to various risks that could result in increased operating costs, limit the areas in which oil and natural gas production may occur and reduce demand for the crude oil and natural gas that we produce.

Climate change continues to attract considerable public, governmental and scientific attention. As a result, numerous proposals have been made and could continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of GHG. These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs and regulations that directly limit GHG emissions from certain sources. At the federal level, the U.S. Congress has from time to time considered climate change legislation, but no comprehensive climate change legislation has been adopted. The EPA, however, has adopted regulations under the existing CAA to restrict emissions of GHG. For example, the EPA imposes preconstruction and operating permit requirements on certain large stationary sources that are already potential sources of certain other significant pollutant emissions. The EPA also adopted rules requiring the monitoring and reporting of GHG emissions on an annual basis from specified large GHG emission sources in the United States, including onshore and offshore oil and natural gas production facilities. Federal agencies have also begun directly regulating emissions of methane, a GHG, from oil and natural gas operations as described above. Compliance with these rules or other could result in increased compliance costs on our operations.

Additionally, state implementation of revised air emission standards could result in stricter permitting requirements, delay, limit or prohibit our ability to obtain such permits and result in increased expenditures for pollution control equipment, the costs of which could be significant. At the international level, the United Nations-sponsored Paris Agreement requires member states to submit non-binding, individually-determined emissions reduction goals every five years after 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 became effective on February 19, 2021.

Governmental, scientific and public concern over the threat of climate change arising from GHG emissions has resulted in increasing federal political risks in the United States. On January 27, 2021, President Biden issued an executive order that commits to substantial action on climate change, calling for, among other things, the elimination of subsidies provided to the fossil fuel industry, increased production of offshore wind energy and increased emphasis on climate-related risks across governmental agencies and economic sectors. The Biden Administration has also taken actions to limit oil and gas development activities on the OCS; for more information, see Part I, Item I. Business – Government Regulation – *Outer Continental Shelf ("OCS") Regulation.*" Other actions that could be pursued by the Biden Administration include more restrictive requirements for the establishment of pipeline infrastructure or the permitting of liquefied natural gas export facilities, as well as more stringent emissions standards for oil and gas facilities. Litigation risks are also increasing, as a number of cities, local governments and other plaintiffs have sought to bring suit against oil and natural gas companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing fuels that contributed to global warming effects, such as rising sea levels and therefore are responsible for roadway and infrastructure damages as a result, or alleging that the companies have been aware of the adverse effects of climate change for some time but defrauded their investors or customers by failing to adequately disclose those impacts. 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 significantly impact our operations and could have an adverse impact on our financial condition.

There are also increasing financial risks for fossil fuel producers as stockholders and bondholders currently invested in fossil fuel energy companies concerned about the potential effects of climate change may elect in the future to shift some or all of their investments into non-fossil fuel energy related sectors. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices, and some of them may elect not to provide funding for fossil fuel energy companies. Additionally, the lending practices of institutional lenders have been the subject of intensive lobbying efforts in recent years, oftentimes public in nature, by environmental activists, proponents of the international Paris Agreement and foreign citizenry concerned about climate change not to provide funding for fossil fuel producers. Limitation of investments in and financings for fossil fuel energy companies could result in the restriction, delay or cancellation of drilling programs or development or production activities.

The adoption of legislation or regulatory programs to reduce or eliminate future emissions of GHG could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce or eliminate future emissions of GHG could have an adverse effect on our business, financial condition and results of operations. Also, political, financial and litigation risks may result in our restricting or canceling production activities, incurring liability for infrastructure damages as a result of climatic changes or impairing the ability to continue to operate in an economic manner.

Finally, some scientists have concluded that increasing concentrations of GHG in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events. Our offshore operations are particularly at risk from severe climatic events. If any such effects of climate changes were to occur, they could have an adverse effect on our financial condition and results of operations.

The enactment of derivatives legislation could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The Dodd-Frank Act, enacted on July 21, 2010, expanded federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The Dodd-Frank Act requires the CFTC and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act. Although the CFTC and the SEC have finalized certain regulations, others remain to be finalized or implemented and it is not possible at this time to predict when this is accomplished.

In one of its rulemaking proceedings still pending under the Dodd-Frank Act, the CFTC issued on December 5, 2016, re-proposed rules imposing position limits for certain futures and option contracts in various commodities (including oil and gas) and for swaps that are their economic equivalents. Under the proposed rules on position limits, certain types of hedging transactions are exempt from these limits on the size of positions that may be held, provided that such hedging transactions satisfy the CFTC's requirements for certain enumerated "bona fide hedging" transactions or positions. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and the associated rules also requires us, in connection with covered derivative activities, to comply with clearing and trade-execution requirements or to take steps to qualify for an exemption to such requirements. Although we expect to qualify for the end-user exception from the mandatory clearing requirements for swaps to be entered into to hedge our commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. In addition, certain banking regulators and the CFTC have recently adopted final rules establishing minimum margin requirements for uncleared swaps. Although we expect to qualify for, and to utilize, the end-user exception from such margin requirements for swaps to be entered into to hedge our commercial risks, the application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. If any of our swaps do not qualify for the commercial end-user exception, posting of collateral could impact liquidity and reduce cash available to us for capital expenditures, therefore reducing our ability to execute hedges to reduce risk and protect cash flows.

The full impact of the Dodd-Frank Act and related regulatory requirements upon our business will not be known until the regulations are fully implemented and the market for derivatives contracts has adjusted. The Dodd-Frank Act 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 may encounter or reduce our ability to monetize or restructure our existing derivative contracts. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations implementing the Dodd-Frank Act, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and implementing 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.

In addition, the European Union and other non-U.S. jurisdictions have implemented and continue to implement new regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions, we may become directly subject to such regulations and in any event the global derivatives market are affected to the extent that foreign counterparties are affected by such regulations. At this time, the impact of such regulations is not clear.

If securities or industry analysts do not publish research or reports about our business, if they adversely change their recommendations regarding our common stock or if our operating results do not meet their expectations, the price of our common stock could decline.

The trading market for our common stock will be influenced by the research and reports that industry or securities analysts publish about us or our business. If one or more of these analysts cease coverage of us or fail to publish reports on us regularly, we could lose visibility in the financial markets, which in turn could cause our stock price or trading volume to decline. Moreover, if one or more of the analysts who cover us downgrades our common stock or if our operating results do not meet their expectations, our stock price could decline.

Negative publicity may adversely impact us.

Media coverage and public statements that insinuate improper actions by us, regardless of their factual accuracy or truthfulness, may result in negative publicity, litigation or governmental investigations by regulators. Addressing negative publicity and any resulting litigation or investigations may distract management, increase costs and divert resources. Negative publicity may have an adverse impact on our reputation and the morale of our employees, which could materially adversely affect our business, financial position, results of operations, cash flows, growth prospects and stock price.

A change in the jurisdictional characterization of our FERC-jurisdictional pipelines, tribal or local regulatory agencies or a change in policy by those agencies may result in increased regulation of such asset, which may cause our revenues to decline and operating expenses to increase or delay or increase the cost of expansion projects.

SP 49 Pipeline LLC is considered a common carrier pipeline subject to regulation by the FERC under the ICA. The ICA requires that we maintain a tariff on file with the FERC for SP 49 Pipeline LLC that sets forth the rates we charge for providing transportation service as well as the rules and regulations governing such service. The ICA requires, among other things, that the rates, terms and conditions of service on interstate common carrier pipelines be “just and reasonable” and non-discriminatory. In the event a shipper protests the rates, terms or conditions of service in effect pursuant to the tariff, we may be required to modify such rates, terms or conditions, which could adversely affect the results of our operations. With respect to CKB Petroleum, Inc., which has been granted a waiver of certain portions of the ICA and related regulations by the FERC, should the pipeline’s circumstances change, the FERC could, either at the request of other entities or on its own initiative, assert that such pipeline no longer qualifies for a waiver. In the event that the FERC were to determine that CKB Petroleum, Inc. no longer qualified for a waiver, we would likely be required to file a tariff with the FERC, provide a cost justification for the transportation charge and provide service to all potential shippers without undue discrimination. Such a change in the jurisdictional status of transportation on the CKB Petroleum, Inc. pipeline could adversely affect our results of operations.

Risks Related to our Capital Structure and Ownership of our Common Stock

Our debt level and the covenants in our current or future agreements governing our debt, including our Bank Credit Facility and the indenture for our 11.00% Second-Priority Senior Secured Notes, could negatively impact our financial condition, results of operations and business prospects. Our failure to comply with these covenants could result in the acceleration of our outstanding indebtedness.

The terms of the agreements governing our debt impose significant restrictions on our ability to take a number of actions that we may otherwise desire to take, including:

- incurring additional debt;
- paying dividends on stock, redeeming stock or redeeming subordinated debt;
- making investments;
- creating liens on our assets;
- selling assets;
- guaranteeing other indebtedness;
- entering into agreements that restrict dividends from our subsidiaries to us;
- merging, consolidating or transferring all or substantially all of our assets;
- hedging future production; and
- entering into transactions with affiliates.

Our level of indebtedness, and the covenants contained in the agreements governing our debt, including the Bank Credit Facility and the indenture for our 11.00% Second-Priority Senior Secured Notes due 2022 (the "11.00% Notes") of Talos Production Inc. and Talos Production Finance, Inc. (together, the "Talos Issuers"), have important consequences on our operations, including:

- requiring that we dedicate a substantial portion of our cash flow from operating activities to required payments on debt, thereby reducing the availability of cash flow for working capital, capital expenditures, and other general business activities;
- limiting our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions and other general business activities;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- detracting from our ability to successfully withstand a downturn in our business or the economy generally;
- placing us at a competitive disadvantage against other less leveraged competitors; and
- making us vulnerable to increases in interest rates because debt under our Bank Credit Facility is at variable rates.

We may be required to repay all or a portion of our debt on an accelerated basis in certain circumstances. If we fail to comply with the covenants and other restrictions in the agreements governing our debt, it could lead to an event of default and the acceleration of repayment of outstanding debt. Our ability to comply with these covenants and other restrictions may be affected by events beyond our control, including prevailing economic and financial conditions. Sustained low oil and natural gas prices have a material and adverse effect on our liquidity position. Our cash flow is highly dependent on the prices we receive for oil and natural gas, which have declined significantly as compared to mid-2014.

We depend on our Bank Credit Facility for a portion of our future capital needs. We are required to comply with certain debt covenants and certain financial ratios under the Bank Credit Facility. Our borrowing base under the Bank Credit Facility, which is redetermined semi-annually, is based on an amount established by the lenders after their evaluation of our proved oil and natural gas reserve values. If, due to a redetermination of our borrowing base, our outstanding borrowings plus outstanding letters of credit exceed our redetermined borrowing base (referred to as a borrowing base deficiency), we could be required to repay such borrowing base deficiency. Our Bank Credit Facility allows us to cure a borrowing base deficiency through any combination of the following actions: (i) repay amounts outstanding sufficient to cure the borrowing base deficiency within 30 days after the existence of such deficiency; (ii) add additional oil and gas properties acceptable to the banks to the borrowing base and take such actions necessary to grant the banks a mortgage in such oil and gas properties within 30 days after the existence of such deficiency; (iii) pay the deficiency in four equal monthly installments with the first installment due within 30 days after the existence of such deficiency or (iv) any combination of the above. We are required to elect one of the foregoing options within 10 days after the existence of such deficiency.

We may not have sufficient funds to make such repayments. If we do not repay our debt out of cash on hand, we could attempt to restructure or refinance such debt, reduce or delay investments and capital expenditures, sell assets, or repay such debt with the proceeds from an equity offering. We cannot assure you that we will be able to generate sufficient cash flows from operating activities to pay the interest on our debt or that future borrowings, equity financings or proceeds from the sale of assets are available to pay or refinance such debt. Any refinancing of indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict business operations. The terms of our debt, including our Bank Credit Facility and the indenture for our 11.00% Notes, may also prohibit us from taking such actions. Factors that affect our ability to raise cash through offerings of our capital stock, a refinancing of our debt or a sale of assets include financial market conditions and our market value and operating performance at the time of such offerings, refinancing or sale of assets. We cannot assure you that any such offerings, restructuring, refinancing or sale of assets would be successfully completed.

A financial crisis may impact our business and financial condition and may adversely impact our ability to obtain funding under our Bank Credit Facility or in the capital markets.

We use our cash flows from operating activities and borrowings under our Bank Credit Facility to fund our capital expenditures, and we rely on the capital markets and asset monetization transactions to provide us with additional capital for large or exceptional transactions. However, COVID-19 and numerous public and political responses thereto have contributed to equity market volatility and the potential risk of a global recession, and we expect this global equity market volatility to continue at least until the outbreak of COVID-19 stabilizes, if not longer. As such, we may not be able to access adequate funding under our Bank Credit Facility as a result of (i) a decrease in our borrowing base due to the outcome of a borrowing base redetermination or a breach or default under our Bank Credit Facility, including a breach of a financial covenant or (ii) an unwillingness or inability on the part of our lending counterparties to meet their funding obligations. We may also face limitations on our ability to access the debt and equity capital markets and complete asset sales, increased counterparty credit risk on our derivatives contracts and requirements by our contractual counterparties to post collateral guaranteeing performance.

In addition, from time to time, we could be required to, or we or our affiliates may seek to, retire or purchase our outstanding debt through cash purchases and/or exchanges for equity or debt, open-market purchases, privately negotiated transactions or other transactions. Such debt repurchase or exchange transactions, if any, will be upon such terms and at such prices as we may determine and will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material. Such transactions may give rise to taxable cancellation of indebtedness income (to the extent the fair market value of the property exchanged, or the amount of cash paid to acquire the outstanding debt, is less than the adjusted issue price of the outstanding debt) and adversely impact our ability to deduct interest expenses in respect of our debt against our taxable income in the future. This could result in a current or future tax liability, which could adversely affect our financial condition and cash flows.

We require substantial capital expenditures to conduct our operations and replace our production, and we may be unable to obtain needed financing on satisfactory terms necessary to fund our planned capital expenditures.

We spend a substantial amount of capital for the acquisition, exploration, exploitation, development, and production of oil and natural gas reserves. We fund our capital expenditures primarily through operating cash flows, cash on hand and borrowings under our Bank Credit Facility, if necessary. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, oil and natural gas prices, actual drilling results, the availability of drilling rigs and other services and equipment and regulatory, technological and competitive developments. A further reduction in commodity prices may result in a further decrease in our actual capital expenditures, which would negatively impact our ability to grow production.

Our cash flow from operations and access to capital is subject to a number of variables, including:

- our proved reserves;
- the level of hydrocarbons we are able to produce from our wells;
- the prices at which our production is sold;
- our ability to acquire, locate and produce new reserves; and
- our ability to borrow under our Bank Credit Facility.

If low oil and natural gas prices, operating difficulties, declines in reserves or other factors, many of which are beyond our control, cause our revenues, cash flows from operating activities, and the borrowing base under our Bank Credit Facility to decrease, we may be limited in our ability to fund the capital necessary to complete our capital expenditure program. After utilizing our available sources of financing, we may be forced to raise additional debt or equity proceeds to fund such capital expenditures. We cannot be sure that additional debt or equity financing will be available, and we cannot be sure that cash flows provided by operations will be sufficient to meet these requirements. For example, the ability of oil and gas companies to access the equity and high yield debt markets has been, and continues to be, significantly limited since the significant decline in commodity prices as compared to mid-2014.

We are a holding company that has no material assets other than our ownership of the equity interests of Talos Production Inc. Accordingly, we are dependent upon distributions from Talos Production Inc. to pay taxes, cover our corporate and other overhead expenses and pay dividends, if any, on our common stock.

We are a holding company that has no material assets other than our ownership of the equity interests of Talos Production Inc. We have no independent means of generating revenue. To the extent Talos Production Inc. has available cash, we will cause Talos Production Inc. to make distributions of cash to us, directly and indirectly through our wholly owned subsidiaries, to pay taxes, cover our corporate and other overhead expenses and pay dividends, if any, on our common stock. As we have never declared or paid any cash dividends on our common stock, we anticipate that any available cash, other than the cash distributed to us to pay taxes and cover our corporate and other overhead expenses, will be retained by Talos Production Inc. to satisfy its operational and other cash needs. Accordingly, we do not anticipate paying any cash dividends on our common stock in the foreseeable future. Although we do not expect to pay dividends on our common stock, if our board of directors decides to do so in the future, our ability to do so may be limited to the extent Talos Production Inc. is limited in its ability to make distributions to us, including the significant restrictions the agreements governing Talos Production Inc.'s debt impose on the ability of Talos Production Inc. to make distributions and other payments to us. To the extent that we need funds and Talos Production Inc. is restricted from making such distributions under applicable law or regulation or under the terms of our financing agreements, or is otherwise unable to provide such funds, it could materially adversely affect our liquidity and financial condition.

Our estimates of future asset retirement obligations may vary significantly from period to period and unanticipated decommissioning costs could materially adversely affect our future financial position and results of operations.

We are required to record a liability for the discounted present value of our asset retirement obligations to plug and abandon inactive, non-producing wells, to remove inactive or damaged platforms, facilities and equipment, and to restore the land or seabed at the end of oil and natural gas operations. These costs are typically considerably more expensive for offshore operations as compared to most land-based operations due to increased regulatory scrutiny and the logistical issues associated with working in waters of various depths. Estimating future restoration and removal costs in the U.S. Gulf of Mexico is especially difficult because most of the removal obligations may be many years in the future, regulatory requirements are subject to change or more restrictive interpretation, and asset removal technologies are constantly evolving, which may result in additional or increased or decreased costs. As a result, we may significantly increase or decrease our estimated asset retirement obligations in future periods. For example, because we operate in the U.S. Gulf of Mexico, platforms, facilities and equipment are subject to damage or destruction as a result of hurricanes and other adverse weather conditions. The estimated costs to plug and abandon a well or dismantle a platform can change dramatically if the host platform from which the work was anticipated to be performed is damaged or toppled rather than structurally intact. Accordingly, our estimates of future asset retirement obligations could differ dramatically from what we may ultimately incur as a result of damage from a hurricane or other natural disaster. Also, a sustained lower commodity price environment may cause our non-operator partners to be unable to pay their share of costs, which may require us to pay our proportionate share of the defaulting party's share of costs.

We may not realize all of the anticipated benefits from our future acquisitions, and we may be unable to successfully integrate future acquisitions.

Our growth strategy will, in part, rely on acquisitions. We have to plan and manage acquisitions effectively to achieve revenue growth and maintain profitability in our evolving market. We expect to grow in the future by expanding the exploitation and development of our existing assets, in addition to growing through targeted acquisitions in the U.S. Gulf of Mexico or in other basins. We may not realize all of the anticipated benefits from our future acquisitions, such as increased earnings, cost savings and revenue enhancements, for various reasons, including difficulties integrating operations and personnel, higher than expected acquisition and operating costs or other difficulties, inexperience with operating in new geographic regions, unknown liabilities, inaccurate reserve estimates and fluctuations in market prices.

In addition, integrating acquired businesses and properties involves a number of special risks and unforeseen difficulties can arise in integrating operations and systems and in retaining and assimilating employees. These difficulties include, among other things:

- operating a larger organization;
- coordinating geographically disparate organizations, systems and facilities;
- integrating corporate, technological and administrative functions;
- diverting management's attention from regular business concerns;
- diverting financial resources away from existing operations;
- increasing our indebtedness; and
- incurring potential environmental or regulatory liabilities and title problems.

Any of these or other similar risks could lead to potential adverse short-term or long-term effects on our operating results. The process of integrating our operations could cause an interruption of, or loss of momentum in, the activities of our business. Members of our management may be required to devote considerable amounts of time to this integration process, which decreases the time they have to manage our business. If our management is not able to effectively manage the integration process, or if any business activities are interrupted as a result of the integration process, our business could suffer.

Our future acquisitions could expose us to potentially significant liabilities, including P&A liabilities.

We expect that future acquisitions will contribute to our growth. In connection with potential future acquisitions, we may only be able to perform limited due diligence.

Successful acquisitions of oil and natural gas properties require an assessment of a number of factors, including estimates of recoverable reserves, the timing of recovering reserves, exploration potential, future oil and natural gas prices, operating costs and potential environmental, regulatory and other liabilities, including P&A liabilities. Such assessments are inexact and may not disclose all material issues or liabilities. In connection with our assessments, we perform a review of the acquired properties. However, such a review may not reveal all existing or potential problems. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities.

There may be threatened, contemplated, asserted or other claims against the acquired assets related to environmental, title, regulatory, tax, contract, litigation or other matters of which we are unaware, which could materially and adversely affect our production, revenues and results of operations. We may be successful in obtaining contractual indemnification for preclosing liabilities, including environmental liabilities, but we expect that we will generally acquire interests in properties on an "as is" basis with limited remedies for breaches of representations and warranties. In addition, even if we are able to obtain such indemnification from the sellers, these indemnification obligations usually expire over time and could potentially expose us to unindemnified liabilities, which could materially adversely affect our production, revenues and results of operations.

Resolution of litigation could materially affect our financial position and results of operations.

Resolution of litigation could materially affect our financial position and results of operations. To the extent that potential exposure to liability is not covered by insurance or insurance coverage is inadequate, we may incur losses that could be material to our financial position or results of operations in future periods.

We are controlled by Apollo Funds and Riverstone Funds. The interests of Apollo Funds and Riverstone Funds may differ from the interests of our other stockholders.

As of December 31, 2020, the funds and other alternative investment vehicles managed by Apollo Management VII, L.P. and Apollo Commodities Management, L.P., with respect to Series I ("Apollo Funds") and entities controlled by or affiliated with Riverstone Energy Partners V, L.P. ("Riverstone Funds") beneficially owned and possessed voting power over 55.5% of our common stock. Under the Stockholders' Agreement, the Apollo Funds and the Riverstone Funds may acquire additional shares of our common stock without the approval of our Independent Directors as defined in that certain Stockholders' Agreement, dated as of May 10, 2018 (the "Stockholders' Agreement").

Through their ownership of a majority of our voting power and the provisions set forth in our Amended and Restated Certificate of Incorporation, our Amended and Restated Bylaws and the Stockholders' Agreement, the Apollo Funds and the Riverstone Funds have the ability to designate a majority of our directors to be nominated for election by our stockholders. As a result of the Apollo Funds' and the Riverstone Funds' ownership of a majority of the voting power of our common stock, we are a "controlled company" as defined in the New York Stock Exchange ("NYSE") listing rules and, therefore, we are not subject to NYSE requirements that would otherwise require us to have a majority of independent directors and nominating and compensation committees composed solely of independent directors. We have not elected to take advantage of the "controlled company" exemptions available to us, but we may choose to do so in the future.

The Apollo Funds and the Riverstone Funds also have control over all other matters submitted to stockholders for approval, including changes in capital structure, transactions requiring stockholder approval under Delaware law, and corporate governance, subject to the terms of the Stockholders' Agreement that require the Apollo Funds and the Riverstone Funds to vote in a specified manner on certain actions, including their agreement to vote in favor of director nominees not designated by the Apollo Funds and the Riverstone Funds. The Apollo Funds and the Riverstone Funds may have different interests than other holders of our common stock and may make decisions adverse to your interests.

Among other things, the Apollo Funds' and Riverstone Funds' control could delay, defer or prevent a sale of us that our other stockholders support, or, conversely, this control could result in the consummation of such a transaction that other stockholders do not support. This concentrated control could discourage a potential investor from seeking to acquire our common stock and, as a result, might harm the market price of our common stock.

The corporate opportunity provisions in our Amended and Restated Certificate of Incorporation could enable others to benefit from corporate opportunities that might not otherwise be available to us.

Subject to the limitations of applicable law, our Amended and Restated Certificate of Incorporation, among other things:

- permits us to enter into transactions with entities in which one or more of our officers or directors are financially or otherwise interested;
- permits the Apollo Funds, the Riverstone Funds, and any of our officers or directors who is also an officer, director, employee, managing director, or other affiliate of the Apollo Funds or the Riverstone Funds to conduct business that competes with us and to make investments in any kind of property in which we may make investments; and
- provides that if the Apollo Funds, the Riverstone Funds, or any of our officers or directors who is also an officer, director, employee, managing director or other affiliate of the Apollo Funds or the Riverstone Funds becomes aware of a potential business opportunity, transaction or other matter (other than one expressly offered to that director or officer in writing solely in his or her capacity as an director or officer of us), that director or officer will have no duty to communicate or offer that opportunity to us, and will be permitted to communicate or offer that opportunity to any other entity or individual and that director or officer will not be deemed to have acted in a manner inconsistent with his or her fiduciary duty to us or our stockholders.

These provisions create the possibility that a corporate opportunity that would otherwise be available to us may be used for the benefit of others.

Our Amended and Restated Certificate of Incorporation designates the Court of Chancery of the State of Delaware (the "Court of Chancery") as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our stockholders, which could limit our stockholders' ability to obtain a favorable judicial forum for disputes with us or our directors, officers, employees or agents.

Our Amended and Restated Certificate of Incorporation provides that, unless we consent in writing to the selection of an alternative forum, the Court of Chancery will be the sole and exclusive forum for (i) any derivative action or proceeding brought on behalf of us, (ii) any action asserting a claim of breach of a fiduciary duty owed by any of our current or former directors, officers, employees, agents or stockholders (including a beneficial owner of stock) to us or our stockholders, (iii) any action asserting a claim arising pursuant to any provision of the Delaware General Corporation Law, our Amended and Restated Certificate of Incorporation or Amended and Restated Bylaws, or (iv) any action asserting a claim governed by the internal affairs doctrine, in each case subject to the Court of Chancery having personal jurisdiction over the indispensable parties named as defendants in the case. Section 27 of the Exchange Act creates exclusive federal jurisdiction over all suits brought to enforce any duty or liability created by the Exchange Act or the rules and regulations promulgated thereunder. As a result, the exclusive forum provision will not apply to actions arising under the Exchange Act or the rules and regulations promulgated thereunder. However, Section 22 of the Securities Act provides for concurrent federal and state court jurisdiction over actions under the Securities Act and the rules and regulations promulgated thereunder, subject to a limited exception for certain "covered class actions" as defined in Section 16 of the Securities Act and interpreted by the courts. Accordingly, we believe that the exclusive forum provision would apply to actions arising under the Securities Act or the rules and regulations promulgated thereunder, except to the extent a particular action fell within the exception for covered class actions or the exception in the certificate of incorporation described above otherwise applied to such action, which could occur if, for example, the action also involved claims under the Exchange Act. Stockholders will not be deemed, by operation of Article 12 of our Amended and Restated Certificate of Incorporation alone, to have waived claims arising under the federal securities laws and the rules and regulations promulgated thereunder.

Any person or entity purchasing or otherwise acquiring any interest in any share of our capital stock will be deemed to have notice of and consent to these provisions of our Amended and Restated Certificate of Incorporation. This exclusive forum provision may limit a stockholder's ability to bring a claim in a judicial forum that it finds favorable for disputes with us or our directors, officers, employees or agents, which may discourage such lawsuits against us and such persons. Alternatively, if a court were to find these provisions of our Amended and Restated Certificate of Incorporation inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect our business, financial condition or results of operations.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Information regarding our properties is included in Part I, Item 1. Business and Part IV, Item 15. Exhibits, Financial Statement Schedules — Note 3 — *Acquisitions* and Note 4 — *Property, Plant and Equipment.*

Item 3. Legal Proceedings

We are named as a party in certain lawsuits and regulatory proceedings arising in the ordinary course of business. We do not expect that these matters, individually or in the aggregate, will have a material adverse effect on our financial condition.

On May 29, 2020, a lawsuit was filed in the Court of Chancery asserting derivative and class action claims against us relating to the ILX and Castex Acquisition. Specifically, the lawsuit relates to the fairness of the consideration paid for such acquisitions in light of the fact that certain of the sellers are our affiliates. We disagree with the claims made in the lawsuit and we have filed for dismissal. We cannot currently predict the manner and timing of the resolution of this matter and are currently unable to estimate a range of possible losses from such matter.

The following proceedings represent previous Stone litigation that was assumed as part of the Stone Combination.

On November 11, 2013, two lawsuits were filed, and on November 12, 2013, a third lawsuit was filed, against Stone and other named co-defendants, by the Parish of Jefferson (“Jefferson Parish”), on behalf of Jefferson Parish and the State of Louisiana, in the 24th Judicial District Court for the Parish of Jefferson, State of Louisiana, alleging violations of the State and Local Coastal Resources Management Act of 1978, as amended, and the applicable regulations, rules, orders and ordinances thereunder (collectively, the “CRMA”), relating to certain of the defendants’ alleged oil and gas operations in Jefferson Parish, and seeking to recover alleged unspecified damages to the Jefferson Parish Coastal Zone and remedies, including unspecified monetary damages and declaratory relief, restoration of the Jefferson Parish Coastal Zone and related costs and attorney’s fees. In March and April 2016, the Louisiana Attorney General and the Louisiana Department of Natural Resources, respectively, intervened in the three lawsuits. In connection with Stone’s filing of bankruptcy in December 2016, Jefferson Parish dismissed its claims against Stone in two of the three Jefferson Parish Coastal Zone Management lawsuits without prejudice to refiling; the claims of the Louisiana Attorney General and the Louisiana Department of Natural Resources were not similarly dismissed. The Jefferson Parish lawsuits have been removed to the United States District Court for the Eastern District of Louisiana. The plaintiffs have moved to remand the lawsuit to the state courts.

On November 8, 2013, a lawsuit was filed against Stone and other named co-defendants by the Parish of Plaquemines (“Plaquemines Parish”), on behalf of Plaquemines Parish and the State of Louisiana, in the 25th Judicial District Court for the Parish of Plaquemines, State of Louisiana, alleging violations of the CRMA, relating to certain of the defendants’ alleged oil and gas operations in Plaquemines Parish, and seeking to recover alleged unspecified damages to the Plaquemines Parish Coastal Zone and remedies, including unspecified monetary damages and declaratory relief, restoration of the Plaquemines Parish Coastal Zone, and related costs and attorney’s fees. In March and April 2016, the Louisiana Attorney General and the Louisiana Department of Natural Resources, respectively, intervened in the lawsuit. In connection with Stone’s filing of bankruptcy in December 2016, Plaquemines Parish dismissed its claims against Stone without prejudice to refiling; the claims of the Louisiana Attorney General and the Louisiana Department of Natural Resources were not similarly dismissed. The Plaquemines Parish lawsuit has been stayed pending the conclusion of trials in five other cases, also filed in Plaquemines Parish and alleging violations of the CRMA, but not involving Stone. The Plaquemines Parish lawsuit has been removed to the United States District Court for the Eastern District of Louisiana. The plaintiffs have moved to remand the lawsuit to the state courts.

Legal proceedings are subject to substantial uncertainties concerning the outcome of material factual and legal issues relating to the litigation. Accordingly, we cannot currently predict the manner and timing of the resolution of some of these matters and may be unable to estimate a range of possible losses or any minimum loss from such matters. See Part IV, Item 15. Exhibits, Financial Statement Schedules — Note 12 — *Commitments and Contingencies* for more information.

Item 4. Mine Safety Disclosures.

Not applicable.

PART II

Item 5. Market for Registrant’s Common Equity, Related Stockholder Matters and Issuers Purchases of Equity Securities

Market for Common Stock

Our common stock is listed on the NYSE under the symbol “TALO”.

Holders of Record

Pursuant to the records of our transfer agent, as of March 3, 2021, there were approximately 189 holders of record of our common stock.

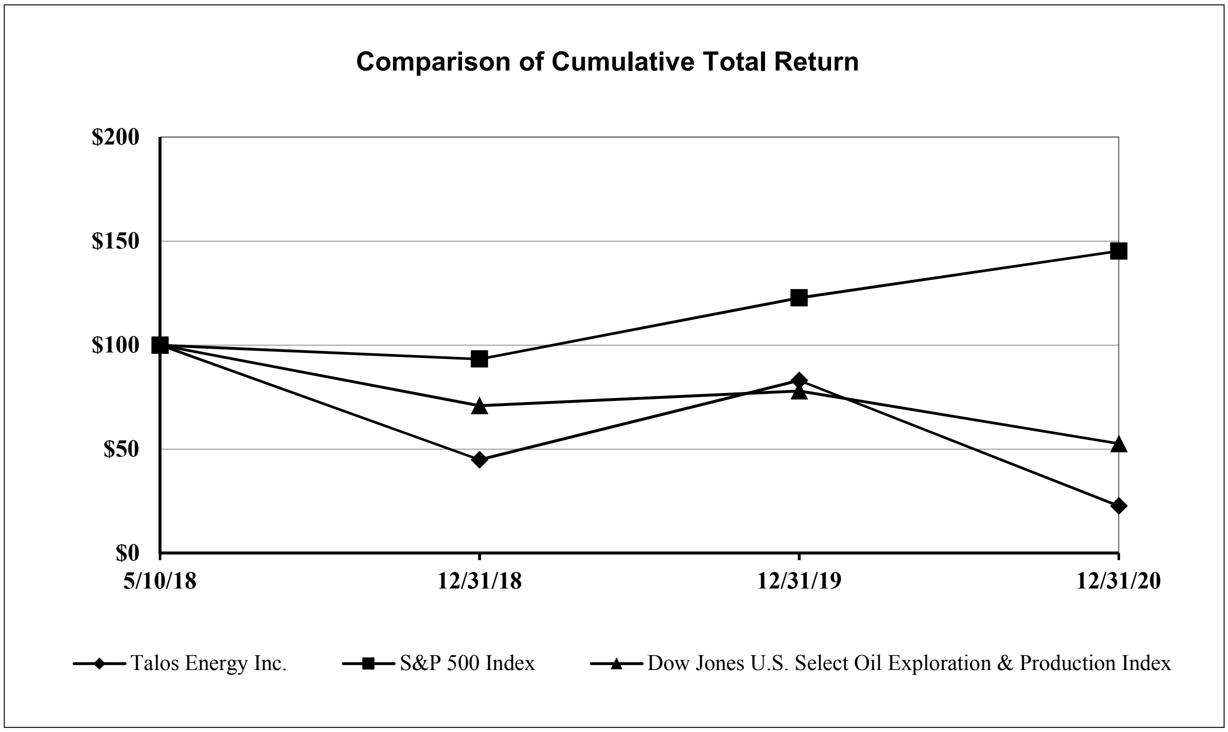
For additional information about shares authorized for issuance under equity compensation plans, see Part IV, Item 15. Exhibits, Financial Statement Schedules — Note 8 — *Employee Benefits Plans and Share-Based Compensation*.

Dividends

We have never declared or paid any cash dividends on our common stock, and we anticipate that any available cash, other than the cash distributed to us to pay taxes and cover our corporate and other overhead expenses, will be retained by Talos Production Inc. to satisfy its operational and other cash needs. Accordingly, we do not anticipate paying any cash dividends on our common stock in the foreseeable future. Although we do not expect to pay dividends on our common stock, if our board of directors decides to do so in the future, our ability to do so may be limited to the extent Talos Production Inc. is limited in its ability to make distributions to us, including the significant restrictions that the agreements governing Talos Production Inc.’s debt impose on the ability of Talos Production Inc. to make distributions and other payments to us.

Stockholder Return Performance Presentation

The following graph is included in accordance with the SEC's executive compensation disclosure rules. This historic stock price performance is not necessarily indicative of future stock performance. The graph compares the change in the cumulative total return of our common stock, the Dow Jones U.S. Exploration and Production Index, and the S&P 500 Index for May 10, 2018 through December 31, 2020. The graph assumes that $100 was invested in our common stock and each index on May 10, 2018 and that dividends were reinvested.



	May 10, 2018	Year Ended December 31, 2018	2019	2020
Talos Energy Inc.	$ 100	$ 45	$ 83	$ 23
S&P 500 Index	$ 100	$ 93	$ 123	$ 145
Dow Jones U.S. Exploration and Production Index	$ 100	$ 71	$ 78	$ 53

The performance graph and the information contained in this section is not "soliciting material," is being "furnished" not "filed" with the SEC and is not to be incorporated by reference into any of our filings under the Securities Act or the Exchange Act whether made before or after the date hereof and irrespective of any general incorporation language contained in such filing.

Item 6. Selected Financial Data

The following table sets forth our selected consolidated historical financial data as of and for the periods ended on the dates indicated below. The selected historical statement of operations data for the years ended December 31, 2020, 2019 and 2018 and the selected historical balance sheet data as of December 31, 2020 and 2019, have been derived from our audited Consolidated Financial Statements and related notes for the year ended December 31, 2020, which are included elsewhere in this report. The selected historical statement of operations data for the years ended December 31, 2017 and 2016, and the selected historical balance sheet data as of December 31, 2018, 2017 and 2016 have been derived from our audited Consolidated Financial Statements, which have not been included in this report. Our Consolidated Financial Statements have been prepared in accordance with GAAP. Our results of operations in any period may not necessarily be indicative of the results that may be expected for any future period. See Part I, Item 1A. Risk Factors for additional information.

As previously described, Stone and Talos Energy LLC became our wholly-owned subsidiaries on the Stone Closing Date in connection with the Stone Combination. Prior to the Stone Closing Date, Talos Energy Inc. had not conducted any material activities other than those incident to its incorporation and certain matters contemplated by the Stone Transaction Agreement. Talos Energy LLC is the acquirer of Stone for financial reporting and accounting purposes. Talos Energy LLC was considered the accounting acquirer in the Stone Combination under GAAP. Accordingly, the selected consolidated historical financial data presented in the tables below, which covers periods prior to the Stone Closing Date, reflects the assets, liabilities and operations of Talos Energy LLC prior to the Stone Closing Date and does not reflect the assets, liabilities and operations of Stone prior to the Stone Closing Date. In addition, we incurred material costs associated with the Stone Combination that are reflected in our historical results of operations for periods prior to the Stone Closing Date, and Talos Energy LLC did not incur United States federal income tax expense or the incremental expense associated with being a public company.

The selected consolidated historical financial information should be read in conjunction with our financial statements and the related notes included elsewhere in this report, as well as Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations (in thousands, except for per share amounts):

	Year Ended December 31,				
	2020[(1)]	2019[(1)]	2018	2017	2016
Consolidated Statements of Operations data:					
Revenues and Other:					
Oil	$ 506,788	$ 833,118	$ 781,815	$ 344,781	$ 197,583
Natural gas	53,714	55,278	73,610	48,886	42,705
NGL	15,434	19,668	35,863	16,658	9,532
Other	11,550	19,556	—	2,503	8,934
Total revenues and other	$ 587,486	$ 927,620	$ 891,288	$ 412,828	$ 258,754
Operating income (expense)	$ (421,310)	$ 213,094	$ 253,129	$ 45,300	$ (80,679)
Net income (loss)	$ (465,605)	$ 58,729	$ 221,540	$ (62,868)	$ (208,087)
Net income (loss) per common share:					
Basic	$ (6.88)	$ 1.08	$ 4.81	$ (2.01)	$ (7.99)
Diluted	$ (6.88)	$ 1.08	$ 4.81	$ (2.01)	$ (7.99)
Weighted average common shares outstanding:					
Basic	67,664	54,185	46,058	31,244	26,036
Diluted	67,664	54,413	46,061	31,244	26,036
Consolidated Balance Sheets data (at period end):					
Total assets	$2,834,546	$2,589,482	$2,479,986	$1,239,293	$1,212,298
Total debt	$ 985,512	$ 732,981	$ 655,304	$ 697,558	$ 701,175
Stockholders' equity (deficit)	$ 926,601	$1,078,277	$1,007,496	$ (54,087)	$ 6,986

(1) For more information, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of our financial condition and results of operations is based on, and should be read in conjunction with our Consolidated Financial Statements and the Notes to Consolidated Financial Statements set forth in Part IV, Item 15. Exhibits, Financial Statement Schedules; Part I, Items 1 and 2. Business and Properties; Part I, Item 1A. Risk Factors; and Part II, Item 7A. Quantitative and Qualitative Disclosures About Market Risk. This discussion and analysis contains forward-looking statements that involve risk and uncertainties. Actual results may differ materially from those anticipated in these forward-looking statements.

This section of this Annual Report generally discusses 2020 and 2019 items and year-to-year comparisons between 2020 and 2019. Discussions of 2018 items and year-to-year comparisons between 2019 and 2018 that are not included in this Annual Report can be found in "Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" of the Company's Annual Report on Form 10-K for the year ended December 31, 2019.

Our Business

We are a technically driven independent exploration and production company focused on safely and efficiently maximizing value through our operations, currently in the U.S. Gulf of Mexico and offshore Mexico. We leverage decades of geology, geophysics and offshore operations expertise towards the acquisition, exploration, exploitation and development of assets in key geological trends that are present in many offshore basins around the world.

We have historically focused our operations in the U.S. Gulf of Mexico because of our deep experience and technical expertise in the basin, which maintains favorable geologic and economic conditions, including multiple reservoir formations, comprehensive geologic and geophysical databases, extensive infrastructure and an attractive and robust asset acquisition market. Additionally, we have access to state-of-the-art three-dimensional seismic data, some of which is aided by new and enhanced reprocessing techniques that have not been previously applied to our current acreage position. We use our broad regional seismic database and our reprocessing efforts to generate a large and expanding inventory of high-quality prospects, which we believe greatly improves our development and exploration success. The application of our extensive seismic database, coupled with our ability to effectively reprocess this seismic data, allows us to both optimize our organic drilling program and better evaluate a wide range of business development opportunities, including acquisitions and joint venture opportunities, among others.

In order to determine the most attractive returns for our drilling program, we employ a disciplined portfolio management approach to stochastically evaluate all of our drilling prospects, whether they are generated organically from our existing acreage, an acquisition or joint venture opportunities. We add to and reevaluate our inventory in order to deploy capital as efficiently as possible.

Outlook

The impacts of the COVID-19 outbreak on our business are unprecedented. Please see Part I, Item 1A. Risk Factors in this Annual Report for additional information. We will continue to focus on maintaining safe and reliable operations, protecting our balance sheet and preserving long-term shareholder value.

COVID-19 — In the first quarter of 2020, the COVID-19 outbreak spread quickly across the globe. Federal, state and local governments mobilized to implement containment mechanisms and minimize impacts to their populations and economies. Various containment measures, such as stay-at-home orders, closures of restaurants and banning of group gatherings have resulted in a severe drop in general economic activity, as well as a corresponding decrease in global energy demand. During 2020, containment measures and responsive actions to the COVID-19 pandemic continued to result in severe declines in general economic activity and energy demand. As a result, the global economy has experienced a slowing of economic growth, disruption of global manufacturing supply chains, stagnation of crude oil and natural gas consumption and interference with workforce continuity. As cities, states and countries continue easing the confinement restrictions, the risk for the resurgence and recurrence of COVID-19 remains. The reinstatement of the containment measures generally, across the globe, has led to an extended period of reduced demand for crude oil and natural gas commodities, as well as asserting further pressure on the global economy. Additionally, the risks associated with COVID-19 have impacted our workforce and the way we meet our business objectives.

Due to concerns over health and safety, we asked the vast majority of our corporate workforce to work remotely. We continue the process of allowing employees to return to the office in phases during the first quarter of 2021. Our offshore employees have continued to work offshore with modified rotations. Working remotely has not significantly impacted our ability to maintain operations, or caused us to incur significant additional expenses; however, we are unable to predict the duration or ultimate impact of these measures. Further, the rapid and unprecedented decreases in energy demand have impacted certain elements of our distribution channels. Inventory surpluses have overwhelmed the United States' storage capacity, leading to a further strain on the supply chain. The Company has evaluated the effect of these factors on the business as we developed a flexible capital spending budget for fiscal year 2021 and shut-in a limited number of operated oil and gas properties. The Company continues to monitor the economic environment, U.S. global and political and economic developments, including the potential for changes to U.S. energy policies, and evaluate their continuing impact on the business.

Decline in Commodity Prices — In March 2020, OPEC and non-OPEC producers failed to agree to production cuts intended to stabilize and support commodity prices. With no agreement in place, Saudi Arabia, Russia and other producers committed to ramping up production in an attempt to protect, or increase, their global market share. This increased production has been coupled with significant demand declines caused by the global response to COVID-19, such as travel restrictions, business closures and the institution of quarantining which has contributed to a decrease in economic activity across the world. These extreme supply and demand dynamics have contributed to significant crude oil price declines. Although pricing stabilized during the fourth quarter of 2020 and increased slightly in 2021, the overall commodity price environment is expected to remain depressed based on over-supply, decreased demand and a potential global economic recession. Saudi Arabia, Russia and other crude oil-producing nations ("OPEC Plus") met in December 2020, with the parties agreeing to increase production by 500,000 barrels a day in January 2021 and, potentially, by a similar amount in the following months; however, that plan was paused during a subsequent meeting in January 2021. The OPEC Plus parties are scheduled to meet again in March 2021 and are expected to choose whether to restore as much as 500,000 barrels a day, the next step in a gradual revival of production that was agreed upon in December 2020. Additionally, Saudi Arabia has recently pledged 1 million barrels a day of voluntary cuts during February and March 2021 but that voluntary commitment is expected to be reconsidered during the March 2021 meeting. It is possible OPEC Plus may agree to further production increases during the March 2021 meeting. As such, we cannot predict whether or when oil production and economic activities will return to normalized levels. The decline in commodity prices has adversely affected oil and natural gas exploration and production in the United States. In response, the Company has developed a flexible fiscal year 2021 capital spending budget that is within operating cash flows and does not require any long-term commitments.

Global Economic Environment — COVID-19 and the numerous public and political responses thereto have contributed to equity market volatility and potentially the risk of a global recession. We expect the global equity market volatility experienced in 2020 to continue at least until the outbreak of COVID-19 stabilizes, if not longer. The response to the COVID-19 outbreak (such as stay-at-home orders, closures of restaurants and banning of group gatherings) and slowing of the global economy has contributed to increased unemployment rates. On March 27, 2020, the U.S. government passed the Coronavirus Aid, Relief, and Economic Security Act (the "CARES Act"), the largest relief package in U.S. history. The CARES Act, a $2.2 trillion stimulus package, includes various provisions intended to provide relief to individuals and businesses in the form of tax law changes, loans and grants, among others. We have evaluated the potential impact of these measures, and we do not meet the criteria to participate. President Biden is currently pursuing a $1.9 trillion stimulus package, which was passed in the U.S. House of Representatives on February 27, 2021 and is now under consideration in the U.S. Senate.

FERC Regulatory Matters — On June 18, 2020, the Federal Energy Regulatory Commission ("FERC") issued a Notice of Inquiry requesting comments on a proposed oil pipeline index using the Producer Price Index for Finished Goods (PPI-FG) plus 0.09% as the index level, and requested comments on whether and how the index should reflect changes to FERC's policies regarding income tax costs and return on equity. FERC issued its Five-Year Review of the Oil Pipeline Index establishing an index level of 0.78% (PPI-FG+0.78%) on December 17, 2020 for the five-year period commencing July 1, 2021. A number of parties requested rehearing of FERC's order and these requests remain pending as a result of FERC's February 18, 2021 order granting rehearing for further consideration. FERC's final application of its indexing rate methodology for the next five-year term of index rates may impact our revenues associated with any transportation services we may provide pursuant to rates adjusted by the FERC oil pipeline index.

Recent Developments

On January 4, 2021, the Company issued $500.0 million in aggregate principal amount of 12.00% Second-Priority Senior Secured Notes due January 2026 (the "12.00% Notes"). The 12.00% Notes were issued pursuant to an indenture dated January 4, 2021 between the Company, Talos Production Inc., the subsidiary guarantors party thereto and Wilmington Trust, National Association, as trustee and collateral agent. On January 14, 2021, we issued an additional $150.0 million in aggregate principal amount of the 12.00% Notes pursuant to the first supplemental indenture dated January 14, 2021. The $150.0 million and $500.0 million in the 12.00% Notes rank pari passu in right of payment and constitute a single class of securities for all purposes under the indenture. The issuances of the 12.00% Notes on January 4, 2021 and January 14, 2021 resulted in $600.5 million in gross proceeds, which was primarily utilized to redeem $347.3 million aggregate principal amount of the 11.00% Notes and to repay $175.0 million of the outstanding borrowings under the Bank Credit Facility during the first quarter of 2021.

As result of the issuances of the 12.00% Notes exceeding $550.0 million, the Bank Credit Facility borrowing base was reduced from $985.0 million to $960.0 million under the terms of the Bank Credit Facility. Additionally, the redemption of the 11.00% Notes eliminated the Bank Credit Facility mandated springing maturity that was 120 days prior to the maturity date of the 11.00% Notes, if greater than $25.0 million of the 11.00% Notes.

Factors Affecting the Comparability of our Financial Condition and Results of Operations

The following items affect the comparability of our financial condition and results of operations for periods presented herein and could potentially continue to affect our future financial condition and results of operations.

***LLOG Acquisition* —** On November 16, 2020, the Company completed the acquisition of select interests in oil and natural gas assets from LLOG Exploration & Production Company, LLC, for $13.2 million in cash, inclusive of customary closing adjustments and transaction related expenses (the "LLOG Acquisition"). See Part IV, Item 15. Exhibits, Financial Statement Schedules — Note 3 — *Acquisitions* for more information.

***Castex 2005 Acquisition* —** On August 5, 2020, the Company completed the acquisition of select interest in oil and natural gas assets from affiliates of Castex Energy 2005 Holdco, LLC, for $43.3 million (comprised of $6.5 million in cash, $35.4 million in 4.6 million shares of the Company's common stock and $1.4 million in transaction related expenses) (the "Castex 2005 Acquisition"). See Part IV, Item 15. Exhibits, Financial Statement Schedules — Note 3 — *Acquisitions* for more information.

***ILX and Castex Acquisition* —** On February 28, 2020 we acquired the outstanding limited liability interests in certain wholly owned subsidiaries of ILX Holdings, LLC, ILX Holdings II, LLC, ILX Holdings III LLC and Castex Energy 2014, LLC, each a related party and an affiliate with the entities controlled by or affiliated with Riverstone Energy Partners V, L.P. (the "Riverstone Sellers"), and Castex Energy 2016, LP (together with the Riverstone Sellers, the "Sellers"), for $459.3 million (comprised of $303.1 million in net cash paid and $156.2 million in 110,000 shares of a series of the Company's preferred stock, which subsequently converted to an aggregate 11.0 million shares of our common stock) (collectively, the "ILX and Castex Acquisition"). See Part IV, Item 15. Exhibits, Financial Statement Schedules — Note 3 — *Acquisitions* for more information.

***Gunflint Acquisition* —** On January 11, 2019, pursuant to a Purchase Sale Agreement with Samson Offshore Mapleleaf, LLC, we acquired an approximate 9.6% non-operated working interest in the Gunflint Field located in the Mississippi Canyon area for $29.6 million ($27.9 million after customary purchase price adjustments). See Part IV, Item 15. Exhibits, Financial Statement Schedules — Note 3 — *Acquisitions* for more information.

***Transaction Expenses* —** We have incurred and will continue to incur transaction related and restructuring costs associated with our business development activities that may vary significantly in our comparative historical results of operations. See Part IV, Item 15. Exhibits, Financial Statement Schedules — Note 3 — *Acquisitions* for more information.

***Hurricanes and Tropical Storms* —** During 2020, production from the U.S. Gulf of Mexico was impacted due to precautionary shut-ins of facilities and evacuations associated with Hurricanes Hanna, Laura, Marco, Sally, Delta and Zeta and Tropical Storms Cristobal and Beta. Although there was no major storm-related damage to our facilities, we incurred production downtime associated with the shut-ins for the storms. For the year ended December 31, 2020, we estimate deferred production related to these storms was approximately 4.1 MBoepd.

Ram Powell Shut-In — Production at our Ram Powell facility was shut-in since late June 2020 while waiting on the repair of the platform's oil export riser. We received final regulatory approvals and completed the repair of the export riser. Production commenced on November 21, 2020. For the year ended December 31, 2020, the Ram Powell facility shut-in resulted in deferred production of 2.1 MBoepd.

Third Party Planned Downtime — Since our operations are offshore, we are vulnerable to third party downtime events impacting the transportation, gathering and processing of production. We produce the Phoenix Field through the HP-I that is operated by Helix Energy Solutions Group, Inc. ("Helix"). Helix is required to disconnect and dry-dock the HP-I every two to three years for inspection as required by the United States Coast Guard, during which time we are unable to produce the Phoenix Field. During the first quarter of 2019, Helix dry-docked the HP-I. After conducting sea trials, production resumed in late March 2019, resulting in a total shut-in period of 57 days.

Known Trends and Uncertainties

Volatility in Oil, Natural Gas and NGL Prices — Historically, the markets for oil and natural gas have been volatile, and prices experienced a steep decline in March and April 2020. In March 2020, Saudi Arabia and Russia failed to reach a decision to cut production of oil and gas along with the OPEC countries. Subsequently, Saudi Arabia significantly reduced the prices at which it sells oil and announced plans to increase production. These events, combined with the continued outbreak of COVID-19, contributed to a sharp drop in prices for oil and natural gas during the year ended December 31, 2020. For example, from January 1, 2020 through December 31, 2020, the daily spot prices for NYMEX WTI crude oil ranged from a high of $63.27 per Bbl to a low of $(36.98) per Bbl and the daily spot prices for NYMEX Henry Hub natural gas ranged from a high of $3.14 per MMBtu to a low of $1.33 per MMBtu. Our revenue, profitability, access to capital and future rate of growth depends upon the price we receive for our sales of oil, natural gas and NGL production. Oil, natural gas and NGL prices are subject to wide fluctuations in supply and demand, and we cannot predict whether or when oil production and economic activities will return to normalized levels.

Impairment of Oil and Natural Gas Properties — Under the full cost method of accounting that we use for our oil and gas operations, our capitalized costs are limited to a ceiling based on the present value of future net revenues from proved reserves, computed using a discount factor of 10 percent, plus the lower of cost or estimated fair value of unproved oil and natural gas properties not being amortized less the related tax effects. Any costs in excess of the ceiling are recognized as a non-cash "Write-down of oil and natural gas properties" on the Consolidated Statements of Operations and an increase to "Accumulated depreciation, depletion and amortization" on our Consolidated Balance Sheets. The expense may not be reversed in future periods, even though higher oil, natural gas and NGL prices may subsequently increase the ceiling. We perform this ceiling test calculation each quarter. In accordance with the SEC rules and regulations, we utilize SEC Pricing when performing the ceiling test. We also hold prices and costs constant over the life of the reserves, even though actual prices and costs of oil and natural gas are often volatile and may change from period to period. During 2020 and 2019 the Company's ceiling test computations resulted in a write down of $267.9 million and nil, respectively. At December 31, 2020, the Company's ceiling test computation was based on SEC pricing of $39.47 per Bbl of oil, $1.97 per Mcf of natural gas and $9.89 per Bbl of NGLs.

If the unweighted average first-day-of-the-month commodity price for crude oil or natural gas for the period beginning January 1, 2020 and ending December 1, 2020 used in the determination of the SEC pricing was 10% lower, resulting in $35.51 per Bbl of oil, $1.76 per Mcf of natural gas and $8.90 per Bbl of NGLs, while all other factors remained constant, our oil and natural gas properties would have been impaired by an additional $446.7 million.

As part of our period end reserves estimation process for future periods, we expect changes in the key assumptions used, which could be significant, including updates to future pricing estimates and differentials, future production estimates to align with our anticipated five-year drilling plan and changes in our capital costs and operating expense assumptions, which we expect to decrease further as a result of sustained lower commodity prices. There is a significant degree of uncertainty with the assumptions used to estimate future undiscounted cash flows due to, but not limited to the risk factors referred to in Part I, Item 1A. Risk Factors. Any decrease in pricing, negative change in price differentials, or increase in capital or operating costs could negatively impact the estimated undiscounted cash flows related to our proved oil and natural gas properties.

BOEM Bonding Requirements — In order to cover the various decommissioning obligations of lessees on the OCS, the BOEM generally requires that lessees post some form of acceptable financial assurances that such obligations will be met, such as surety bonds. The cost of such bonds or other financial assurance can be substantial, and we can provide no assurance that we can continue to obtain bonds or other surety in all cases. As many BOEM regulations are being reviewed by the agency, we may be subject to additional financial assurance requirements in the future. For example, in 2016, the BOEM under the Obama Administration issued the 2016 NTL to clarify the procedures and guidelines that BOEM Regional Directors use to determine if and when additional financial assurances may be required for OCS leases, ROWs and RUEs. The 2016 NTL, which bolstered supplemental bonding requirements, became effective in September 2016, but was not fully implemented as the BOEM under the Trump Administration first paused, and then in 2020 rescinded, the implementation of this NTL while the BOEM and BSEE issued a jointly proposed rulemaking in October 2020 in which BOEM proposed amendments to its financial assurance program. The October 2020 rulemaking proposes to clarify and provide greater transparency to decommissioning and related financial assurance requirements imposed on oil and gas lessees (record title owners), sublessees (operating rights owners) and RUE and ROW grant holders conducting operations on the federal OCS. However, with President Biden taking office in January 2021, it is possible that the new Administration will reconsider regulatory actions undertaken by the former Administration with respect to financial assurance requirements, including rescission of the 2016 NTL and publication of the October 2020 proposed rule, and may adopt and implement more stringent supplemental bonding requirements.

The future cost of compliance with respect to supplemental bonding, including the obligations imposed on us, whether as current or predecessor lessee or grant holder, as a result of the 2016 NTL, to the extent re-implemented or the October 2020 proposed rule, to the extent finalized, as well as to the provisions of any new, more stringent NTLs or final rules on supplemental bonding published by the BOEM under the Biden Administration, could materially and adversely affect our financial condition, cash flows and results of operations. Moreover, the BOEM has the right to issue liability orders in the future, including if it determines there is a substantial risk of nonperformance of the interest holder's decommissioning liabilities.

Deepwater Operations — We have interests in deepwater fields in the U.S. Gulf of Mexico. Operations in the deepwater can result in increased operational risks as has been demonstrated by the Deepwater Horizon disaster in 2010. Despite technological advances since this disaster, liabilities for environmental losses, personal injury and loss of life and significant regulatory fines in the event of a disaster could be well in excess of insured amounts and result in significant current losses on our statements of operations as well as going concern issues.

Oil Spill Response Plan — We maintain a Regional Oil Spill Response Plan that defines our response requirements, procedures and remediation plans in the event we have an oil spill. Oil Spill Response Plans are generally approved by BSEE bi-annually, except when changes are required, in which case revised plans are required to be submitted for approval at the time changes are made. Additionally, these plans are tested and drills are conducted periodically at all levels.

Hurricanes — Since our operations are in the U.S. Gulf of Mexico, we are particularly vulnerable to the effects of hurricanes on production. Additionally, affordable insurance coverage for property damage to our facilities for hurricanes has become less effective due to rising retentions and limitations on named windstorm coverage and has become difficult to obtain at times in recent years. Significant hurricane impacts could include reductions and/or deferrals of future oil and natural gas production and revenues, increased lease operating expenses for evacuations and repairs and possible acceleration of plugging and abandonment costs.

How We Evaluate Our Operations

We use a variety of financial and operational metrics to assess the performance of our oil and natural gas operations, including:

- production volumes;
- realized prices on the sale of oil, natural gas and NGLs, including the effect of our commodity derivative contracts;
- lease operating expenses;
- capital expenditures; and
- Adjusted EBITDA, which is discussed under "—Supplemental Non-GAAP Measure" below.

Basis of Presentation

Sources of Revenues and Other

Our revenues are derived from the sale of our oil and natural gas production, as well as the sale of NGLs, that are extracted from our natural gas during processing. Our oil, natural gas and NGL revenues do not include the effects of derivatives, which are reported in "Price risk management activities income (expense)" in our Consolidated Statements of Operations. The following table presents a breakout of each revenue component:

	Year Ended December 31,		
	2020	2019	2018
Revenues and Other breakout:			
Oil	86%	90%	88%
Natural gas	9%	6%	8%
NGL	3%	2%	4%
Other	2%	2%	—%

Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices.

Realized Prices on the Sale of Oil, Natural Gas and NGLs **—** The NYMEX WTI prompt month oil settlement price is a widely used benchmark in the pricing of domestic oil in the United States. The actual prices we realize from the sale of oil differ from the quoted NYMEX WTI price as a result of quality and location differentials. For example, the prices we realize on the oil we produce are affected by the Gulf of Mexico Basin's proximity to U.S. Gulf Coast refineries and the quality of the oil production sold in Eugene Island Crude, Louisiana Light Sweet Crude and Heavy Louisiana Sweet Crude markets.

The NYMEX Henry Hub price of natural gas is a widely used benchmark for the pricing of natural gas in the United States. The actual prices we realize from the sale of natural gas differ from the quoted NYMEX Henry Hub price as a result of quality and location differentials. Currently, the sales points of our gas production are generally within close proximity to the Henry Hub which creates a minimal differential in the prices we receive for our production versus average Henry Hub prices.

In the past, oil and natural gas prices have been extremely volatile, and we expect this volatility to continue, as indicated in the table below, which provides the high, low and average prices for NYMEX WTI and NYMEX Henry Hub monthly contract prices as well as our average realized oil, natural gas, and NGL sales prices for the periods indicated.

	Year Ended December 31,		
	2020	2019	2018
Oil:			
NYMEX WTI High per Bbl	$ 57.52	$ 63.86	$ 70.98
NYMEX WTI Low per Bbl	$ 16.55	$ 51.38	$ 49.52
Average NYMEX WTI per Bbl	$ 39.16	$ 56.98	$ 65.23
Average Oil Sales Price per Bbl (including commodity derivatives)	$ 47.36	$ 59.23	$ 57.12
Average Oil Sales Price per Bbl (excluding commodity derivatives)	$ 37.09	$ 60.17	$ 66.42
Natural Gas:			
NYMEX Henry Hub High per MMBtu	$ 2.61	$ 3.11	$ 4.09
NYMEX Henry Hub Low per MMBtu	$ 1.63	$ 2.22	$ 2.67
Average NYMEX Henry Hub per MMBtu	$ 2.03	$ 2.56	$ 3.15
Average Natural Gas Sales Price per Mcf (including commodity derivatives)	$ 2.00	$ 2.55	$ 3.16
Average Natural Gas Sales Price per Mcf (excluding commodity derivatives)	$ 1.87	$ 2.37	$ 3.23
NGLs:			
NGL Realized Price as a % of Average NYMEX WTI	25%	28%	47%

To achieve more predictable cash flow, and to reduce exposure to adverse fluctuations in commodity prices, from time to time we enter into commodity derivative arrangements for our anticipated production. By removing a significant portion of price volatility associated with our anticipated production, we believe it will mitigate, but not eliminate, the potential negative effects of reductions in oil and natural gas prices on our cash flow from operations for those periods. However, our price risk management activity may also reduce our ability to benefit from increases in prices. We will sustain losses to the extent our commodity derivatives contract prices are lower than market prices and, conversely, we will sustain gains to the extent our commodity derivatives contract prices are higher than market prices.

We will continue to use commodity derivative instruments to manage commodity price risk in the future. Our hedging strategy and future hedging transactions will be determined at our discretion and may be different from what we have done on a historical basis.

Expenses

Lease operating expense — Lease operating expense consists of the daily costs incurred to bring oil, natural gas and NGLs out of the underground formation and to the market, together with the daily costs incurred to maintain our producing properties. Expenses for direct labor, insurance, a portion of the HP-I lease, materials and supplies, rental and third party costs comprise the most significant portion of our lease operating expense. It further consists of costs associated with major remedial operations on completed wells to restore, maintain or improve the well's production. Because the amount of workover and maintenance expense is closely correlated to the levels of workover activity, which is not regularly scheduled, workover and maintenance expense is not necessarily comparable from period to period.

Production taxes — Production taxes consist of severance taxes levied by the Louisiana Department of Revenue on production of oil and natural gas from land or water bottoms within the boundaries of the state of Louisiana.

Depreciation, depletion and amortization expense — Depreciation, depletion and amortization expense is the expensing of the capitalized costs incurred to acquire, explore and develop oil and natural gas reserves. We use the full cost method of accounting for oil and natural gas activities. See Part IV, Item 15. Exhibits, Financial Statement Schedules — Note 2 — *Summary of Significant Accounting Policies* for further discussion.

Accretion expense — We have obligations associated with the retirement of our oil and natural gas wells and related infrastructure. We have obligations to plug wells when production on those wells is exhausted, when we no longer plan to use them or when we abandon them. We accrue a liability with respect to these obligations based on our estimate of the timing and amount to replace, remove or retire the associated assets. Accretion of the liability is recognized for changes in the value of the liability as a result of the passage of time over the estimated productive life of the related assets as the discounted liabilities are accreted to their expected settlement values.

General and administrative expense — General and administrative expense generally consists of costs incurred for overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our production operations, bad debt expense, equity based compensation expense, audit and other fees for professional services and legal compliance.

Interest expense — We finance a portion of our working capital requirements, capital expenditures and acquisitions with borrowings under our Bank Credit Facility and term based debt. As a result, we incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. Interest includes interest incurred under our debt agreements, the amortization of deferred financing costs (including origination and amendment fees), commitment fees, imputed interest on our capital lease, performance bond premiums and annual agency fees. Interest expense is net of capitalized interest on expenditures made in connection with exploratory projects that are not subject to current amortization.

Price risk management activities — We utilize commodity derivative instruments to reduce our exposure to fluctuations in the price of oil and natural gas. We recognize gains and losses associated with our open commodity derivative contracts as commodity prices and the associated fair value of our commodity derivative contracts change. The commodity derivative contracts we have in place are not designated as hedges for accounting purposes. Consequently, these commodity derivative contracts are marked-to-market each quarter with fair value gains and losses recognized currently as a gain or loss in our results of operations. Cash flow is only impacted to the extent the actual settlements under the contracts result in making a payment to or receiving a payment from the counterparty.

Results of Operations

Revenues and Other

The information below provides a discussion of, and an analysis of significant variance in, our oil, natural gas and NGL revenues, production volumes and sales prices for the years ended December 31, 2020 and 2019 (in thousands):

	Year Ended December 31,		
	2020	2019	Change
Revenues and Other:			
Oil	$ 506,788	$ 833,118	$ (326,330)
Natural gas	53,714	55,278	(1,564)
NGL	15,434	19,668	(4,234)
Other	11,550	19,556	(8,006)
Total revenues and other	$ 587,486	$ 927,620	$ (340,134)
Total Production Volumes:			
Oil (MBbls)	13,665	13,847	(182)
Natural gas (MMcf)	28,652	23,306	5,346
NGL (MBbls)	1,559	1,228	331
Total production volume (MBoe)	19,999	18,959	1,040
Daily Production Volumes by Product:			
Oil (MBblpd)	37.3	37.9	(0.6)
Natural gas (MMcfpd)	78.3	63.9	14.4
NGL (MBblpd)	4.3	3.4	0.9
Total production volume (MBoepd)	54.7	52.0	2.7
Average sale price per unit:			
Oil (per Bbl)	$ 37.09	$ 60.17	$ (23.08)
Natural gas (per Mcf)	$ 1.87	$ 2.37	$ (0.50)
NGL (per Bbl)	$ 9.90	$ 16.02	$ (6.12)
Price per Boe	$ 28.80	$ 47.90	$ (19.10)
Price per Boe (including realized commodity derivatives)	$ 35.99	$ 47.43	$ (11.44)

The information below provides an analysis of the change in our oil, natural gas and NGL revenues, due to changes in sales prices and production volumes for the years ended December 31, 2020 and 2019 (in thousands):

	Price	Volume	Total
Oil	$ (315,379)	$ (10,951)	$ (326,330)
Natural gas	$ (14,234)	$ 12,670	$ (1,564)
NGL	$ (9,537)	$ 5,303	$ (4,234)
Total	$ (339,150)	$ 7,022	$ (332,128)

Volumetric Analysis — Production volumes increased by 2.7 MBoepd to 54.7 MBoepd. The increase in production was primarily attributable to 15.5 MBoepd in production from the oil and natural gas assets acquired in the ILX and Castex Acquisition and Castex 2005 Acquisition. The increase in production volumes was partially offset by a 3.2 MBoepd, 2.9 MBoepd and 1.4 MBoepd reduction in production from the Ram Powell Field, Phoenix Field and Pompano Field, respectively. The decline in the Ram Powell Field was primarily a result of a shut-in for repairs and maintenance on the platform's oil export riser. The Ram Powell Field returned to production during the fourth quarter of 2020. The decline in production volumes in the Phoenix Field and Pompano Field were associated with deferred production for weather related events, rig work, other miscellaneous shut-ins and natural declines, partially offset by first quarter 2019 downtime for the Helix HP-I dry-dock repairs and maintenance in the Phoenix Field.

Expenses

Lease Operating Expense

The following table highlights lease operating expense items in total and on a cost per Boe production basis. The information below provides the financial results and an analysis of significant variances in these results for the years ended December 31, 2020 and 2019 (in thousands, except per Boe data):

	Year Ended December 31,	
	2020	**2019**
Lease operating expenses	$ 246,564	$ 243,427
Lease operating expenses per Boe	$ 12.33	$ 12.84

Total lease operating expense for the year ended December 31, 2020 increased by approximately $3.1 million, or 1%. This increase was primarily related to $44.4 million of lease operating expense in connection with the ILX and Castex Acquisition and $3.8 million of lease operating expense in connection with the Castex 2005 Acquisition. The increase was partially offset by a $34.8 million reduction direct operating expenses, primarily due to shuttering certain shelf fields, cost cutting measures taken due to the current economic environment, reduction in costs attributable to economic shut-ins and an increase in PHA reimbursements. While total lease operating expense increased, lease operating expense per Boe decreased $0.51 per Boe to $12.33 per Boe.

Depreciation, Depletion and Amortization

The following table highlights depreciation, depletion and amortization items in total and on a cost per Boe production basis. The information below provides the financial results and an analysis of significant variances in these results for the years ended December 31, 2020 and 2019 (in thousands, except per Boe data):

	Year Ended December 31,	
	2020	**2019**
Depreciation, depletion and amortization	$ 364,346	$ 345,931
Depreciation, depletion and amortization per Boe	$ 18.22	$ 18.25

Depreciation, depletion and amortization expense for the year ended December 31, 2020 increased by approximately $18.4 million, or 5%. This was due to an increase in production of 2.7 MBoepd as discussed above and offset slightly by a decrease in the depletion rate on our proved oil and natural gas properties of $0.02 per Boe, during the year ended December 31, 2020.

General and Administrative Expense

The following table highlights general and administrative expense items in total and on a cost per Boe production basis. The information below provides the financial results and an analysis of significant variances in these results for the years ended December 31, 2020 and 2019 (in thousands, except per Boe data):

	Year Ended December 31,	
	2020	**2019**
General and administrative expense	$ 79,175	$ 77,209
General and administrative expense per Boe	$ 3.96	$ 4.07

General and administrative expense for the year ended December 31, 2020, increased by approximately $2.0 million, or 3%. Transaction and non-recurring costs were $14.1 million or $0.70 per Boe for 2020, which is an increase of $6.6 million primarily due to the ILX and Castex Acquisition and Castex 2005 Acquisition. The increase was offset with the realized benefit of cost savings initiatives in the current economic environment, primarily related to a reduction of employee and contract labor costs of $5.2 million. On a per unit basis, general and administrative expense decreased $0.11 per Boe.

Other Income and Expense

The following table highlights other income and expense items in total. The information below provides the financial results and an analysis of significant variances in these results for the years ended December 31, 2020 and 2019 (in thousands):

	Year Ended December 31,	
	2020	**2019**
Write-down of oil and natural gas properties	$ 267,916	$ 12,221
Accretion expense	$ 49,741	$ 34,389
Price risk management activities income (expense)	$ 87,685	$ (95,337)
Income tax benefit (expense)	$ (35,583)	$ 36,141

***Write-down of oil and natural gas properties* —** During the year ended December 31, 2020, we recorded a $267.9 million write-down of our oil and natural gas properties. The write-down is a result of our ceiling test evaluation as described in Part IV, Item 15. Exhibits, Financial Statement Schedules — Note 4 — *Property, Plant and Equipment*.

***Price risk management activities* —** Price risk management activities for year ended December 31, 2020, increased by approximately $183.0 million, or 192%. The income of $87.7 million for the year ended December 31, 2020 consists of $143.9 million in cash received on settled derivative instruments gains and $56.2 million in non-cash losses from the decrease in the fair value of our open derivative contracts. The expense of $95.3 million for the year ended December 31, 2019 consists of $8.8 million in cash paid on settled derivative instruments losses and $86.5 million in non-cash losses from the decrease in the fair value of our open derivative contracts. These unrealized gains on open derivative contracts relate to production for future periods; however, changes in the fair value of all of our open derivative contracts are recorded as a gain or loss on our Consolidated Statements of Operations at the end of each month. As a result of the derivative contracts we have on our anticipated production volumes through 2023, we expect these activities to continue to impact net income (loss) based on fluctuations in market prices for oil and natural gas.

***Income tax benefit (expense)* —** During the year ended December 31, 2020, we recorded $35.6 million of income tax expense compared to $36.1 million of income tax benefit during the year ended December 31, 2019. The change is primarily a result of the reversal and subsequent recording of a valuation allowance on our deferred tax assets. The realization of our deferred tax asset depends on recognition of sufficient future taxable income in specific tax jurisdictions in which temporary differences or net operating losses relate. In assessing the need for a valuation allowance, we consider whether it is more likely than not that some portion of all of the deferred tax assets will not be realized. See additional information on the valuation allowance as described in Part IV, Item 15. Exhibits, Financial Statement Schedules — Note 9 — *Income Taxes*.

Commitments and Contingencies

For a further discussion of our commitments and contingencies, see Part IV, Item 15. Exhibits, Financial Statement Schedules — Note 12 — *Commitments and Contingencies*. Additionally, we are party to lawsuits arising in the ordinary course of our business. We cannot predict the outcome of any such lawsuit with certainty, but our management believes it is remote that any such pending or threatened lawsuit will have a material adverse impact on our financial condition. See Part I, Item 3. Legal Proceedings for additional information.

Due to the nature of our business, we are, from time to time, involved in other routine litigation or subject to disputes or claims related to business activities, including workers' compensation claims, employment related disputes and civil penalties by regulators. In the opinion of our management, none of these other pending litigations, disputes or claims against us, if decided adversely, will have a material adverse effect on our financial condition, cash flows or results of operations. See Part I, Item 3. Legal Proceedings for additional information.

Supplemental Non-GAAP Measure

EBITDA and Adjusted EBITDA

"EBITDA" and "Adjusted EBITDA" are non-GAAP financial measures used to provide management and investors with (i) additional information to evaluate, with certain adjustments, items required or permitted in calculating covenant compliance under our debt agreements, (ii) important supplemental indicators of the operational performance of our business, (iii) additional criteria for evaluating our performance relative to our peers and (iv) supplemental information to investors about certain material non-cash and/or other items that may not continue at the same level in the future. EBITDA and Adjusted EBITDA have limitations as analytical tools and should not be considered in isolation or as substitutes for analysis of our results as reported under GAAP or as alternatives to net income (loss), operating income (loss) or any other measure of financial performance presented in accordance with GAAP.

We define these as the following:

EBITDA **—** Net income (loss) plus interest expense, income tax expense (benefit), depreciation, depletion and amortization, and accretion expense.

Adjusted EBITDA **—** EBITDA plus non-cash write-down of oil and natural gas properties, loss on debt extinguishment, transaction related costs, the net change in the fair value of derivatives (mark to market effect, net of cash settlements and premiums related to these derivatives), non-cash (gain) loss on sale of assets, non-cash write-down of other well equipment inventory and non-cash equity based compensation expense.

The following tables present a reconciliation of the GAAP financial measure of net income (loss) to Adjusted EBITDA for each of the periods indicated (in thousands):

	Year Ended December 31,		
	2020	**2019**	**2018**
Reconciliation of net income (loss) to Adjusted EBITDA:			
Net income (loss)	$ (465,605)	$ 58,729	$ 221,540
Interest expense	99,415	97,847	90,114
Income tax expense (benefit)	35,583	(36,141)	2,922
Depreciation, depletion and amortization	364,346	345,931	288,719
Accretion expense	49,741	34,389	35,344
EBITDA	83,480	500,755	638,639
Write-down of oil and natural gas properties	267,916	12,221	—
Transaction and non-recurring expenses[1]	14,917	7,460	32,484
Derivative fair value (gain) loss[2]	(87,685)	95,337	(60,435)
Net cash received (paid) on settled derivative instruments[2]	143,905	(8,820)	(111,147)
Non-cash gain on sale of assets	—	—	(1,710)
(Gain) loss on debt extinguishment	(1,662)	132	1,764
Non-cash write-down of other well equipment inventory	699	165	244
Non-cash equity-based compensation expense (net of amount capitalized)	8,669	6,964	2,893
Adjusted EBITDA	$ 430,239	$ 614,214	$ 502,732

(1) Includes transaction related expenses, restructuring expenses and cost saving initiatives.

(2) The adjustments for the derivative fair value (gains) losses and net cash receipts on settled commodity derivative instruments have the effect of adjusting net loss for changes in the fair value of derivative instruments, which are recognized at the end of each accounting period because we do not designate commodity derivative instruments as accounting hedges. This results in reflecting commodity derivative gains and losses within Adjusted EBITDA on a cash basis during the period the derivatives settled.

Liquidity and Capital Resources

Our primary sources of liquidity are cash generated by our operations and borrowings under our Bank Credit Facility. Our primary uses of cash are for capital expenditures, working capital, debt service and for general corporate purposes. As of December 31, 2020, our available liquidity (cash plus available capacity under the Bank Credit Facility) was $340.7 million, or $365.7 million inclusive of the $25.0 million requiring certain lender approval.

We fund exploration and development activities primarily through operating cash flows, cash on hand and through borrowings under the Bank Credit Facility, if necessary. Historically, we have funded significant property acquisitions with the issuance of senior notes, borrowings under the Bank Credit Facility and through additional equity issuances. We occasionally adjust our capital budget in response to changing operating cash flow forecasts and market conditions, including the prices of oil, natural gas and NGLs, acquisition opportunities and the results of our exploration and development activities.

***Capital Expenditures* —** The following is a table of our capital expenditures, excluding acquisitions, for the year ended December 31, 2020 (in thousands):

U.S. drilling & completions	$	253,753
Mexico appraisal & exploration		732
Asset management		42,606
Seismic and G&G, land, capitalized G&A and other[1]		64,501
Total capital expenditures		361,592
Plugging & abandonment		43,933
Total capital expenditures and plugging & abandonment	$	405,525

(1) Amount excludes $7.8 million of non-cash share-based awards.

Based on our current level of operations and available cash, we believe our cash flows from operations, combined with availability under the Bank Credit Facility, provide sufficient liquidity to fund our board approved 2021 capital spending program of $340.0 million to $370.0 million. However, our ability to (i) generate sufficient cash flows from operations or obtain future borrowings under the Bank Credit Facility, and (ii) repay or refinance any of our indebtedness on commercially reasonable terms or at all for any potential future acquisitions, joint ventures or other similar transactions, depends on operating and economic conditions, some of which are beyond our control. To the extent possible, we have attempted to mitigate certain of these risks (e.g. by entering into oil and natural gas derivative contracts to reduce the financial impact of downward commodity price movements on a substantial portion of our anticipated production), but we could be required to, or we or our affiliates may from time to time, take additional future actions on an opportunistic basis. To address further changes in the financial and/or commodity markets, future actions may include, without limitation, raising debt, including secured debt, or issuing equity to directly or independently repurchase or refinance our outstanding debt.

***Guarantor Financial Information* —** Talos owns no operating assets and has no operations independent of its subsidiaries. The Talos Issuers issued the 11.00% Notes on May 10, 2018, which are fully and unconditionally guaranteed, jointly and severally, by Talos and certain 100% owned subsidiaries (the "Guarantors") on a senior unsecured basis. Our non-domestic subsidiaries (the "Non-Guarantors") are 100% owned by Talos but do not guarantee the 11.00% Notes issued on May 10, 2018.

In lieu of providing separate financial statements for Talos Issuers and Guarantors, we have presented the accompanying supplemental summarized combined balance sheet and income statement information for Talos, the Talos Issuers and Guarantors on a combined basis after elimination of intercompany transactions and amounts related to investment in any subsidiary that is a Non-Guarantor.

The following table presents the balance sheet information for the respective periods (in thousands):

	Year Ended December 31,			
	2020		2019	
Current assets	$	231,669	$	281,008
Non-current assets		2,444,886		2,168,537
Total Assets	$	2,676,555	$	2,449,545
Current liabilities	$	438,340	$	357,893
Non-current liabilities		1,459,816		1,139,859
Talos Energy Inc. stockholders' equity		778,399		951,793
Total liabilities and stockholders' equity	$	2,676,555	$	2,449,545

The following table presents the income statement information for the year ended December 31, 2020 (in thousands):

		Year Ended December 31, 2020
Revenues and Other	$	587,479
Cost and expenses		(1,050,117)
Net Loss	$	(462,638)

Overview of Cash Flow Activities — The following table summarizes cash flows provided by (used in) by type of activity, for the following periods (in thousands):

	Year Ended December 31,			
	2020		2019	
Operating activities	$	301,923	$	393,733
Investing activities	$	(678,904)	$	(495,956)
Financing activities	$	324,192	$	48,083

Operating Activities — Net cash provided by operating activities decreased $91.8 million in 2020 from 2019 primarily attributable to a decrease in revenues of $340.1 million. This was offset by an increase in cash receipts on derivatives of $152.7 million and decrease in settlements of asset retirement obligations of $31.4 million.

Investing Activities — Net cash used in investing activities increased $182.9 million in 2020 from 2019 primarily due to an increase in payments for acquisitions of $278.0 million, which was offset by a decrease in capital expenditures of $100.5 million.

Financing Activities — Net cash provided by financing activities increased $276.1 million in 2020 from 2019 primarily attributable to net proceeds of approximately $205.0 million from the Bank Credit Facility and $71.1 million in proceeds from the issuance of our common stock.

Financing Arrangements — As of December 31, 2020, total debt, net of discount and deferred financing costs, was approximately $985.5 million, comprised of our $343.6 million aggregate principal amount of the 11.00% Notes due 2022 and $6.1 million aggregate principal amount of our 7.50% Senior Notes due 2022 issued by Stone ("7.50% Notes"), and $635.9 million outstanding under our Bank Credit Facility. We were in compliance with all debt covenants at December 31, 2020. For additional details on our debt, see Part IV, Item 15. Exhibits, Financial Statement Schedules — Note 7 — *Debt*.

Bank Credit Facility – matures May 2022 — The Company maintains a Bank Credit Facility with a syndicate of financial institutions, with a borrowing base of $985.0 million as of December 31, 2020. The Bank Credit Facility matures on May 10, 2022, provided that the Bank Credit Facility mandates a springing maturity that is prior to the maturity date of the 11.00% Notes (such 120 days prior being December 4, 2021), if greater than $25.0 million of the 11.00% Notes or any permitted refinancing indebtedness in respect thereof is outstanding on such date. During January 2021, we redeemed the aggregate principal amount of the 11.00% Notes and issued 12.00% Notes. See Part II, Item 7. Management Discussion and Analysis of Financial Condition and Results of Operations — *Recent Developments* for additional information.

The Bank Credit Facility bears interest based on the borrowing base usage, at the applicable LIBOR, plus applicable margins ranging from 3.00% to 4.00% or an alternate base rate based on the federal funds effective rate plus applicable margins ranging from 2.00% to 3.00%. In addition, we are obligated to pay a commitment fee of 0.50% on the unutilized portion of the commitments. The Bank Credit Facility has certain debt covenants, the most restrictive of which requires that we maintain a total debt to EBITDAX Ratio (as defined in the Bank Credit Facility) of no greater than 3.00 to 1.00 calculated each quarter utilizing the most recent twelve months to determine EBITDAX. We must also maintain a current ratio no less than 1.00 to 1.00 each quarter. According to the Bank Credit Facility, unutilized commitments are included in current assets in the current ratio calculation. The Bank Credit Facility is secured by substantially all of our oil and natural gas assets. The Bank Credit Facility is fully and unconditionally guaranteed by us and certain of our wholly-owned subsidiaries.

The Bank Credit Facility provides for determination of the borrowing base based on our proved producing reserves and a portion of our PUD reserves. The borrowing base is redetermined by the lenders at least semi-annually during the second quarter and fourth quarter each year. Upon closing of the ILX and Castex Acquisition on February 28, 2020, the maximum borrowing base and commitments were increased from $950.0 million to $1.15 billion. On June 19, 2020, the borrowing base was redetermined by the lenders and decreased from $1.15 billion to $985.0 million. The redetermination on June 19, 2020 also required certain lender approval to access the last $25.0 million of the borrowing base. On December 7, 2020, the borrowing base was reaffirmed at $985.0.

As of December 31, 2020, no more than $200.0 million of the borrowing base can be used as letters of credit. The amount that we are able to borrow with respect to the borrowing base is subject to compliance with the financial covenants and other provisions of the Bank Credit Facility. We were in compliance with all debt covenants at December 31, 2020. As of December 31, 2020, the Company has $640.0 million of outstanding borrowings and $13.6 million letters of credit issued under the Bank Credit Facility.

11.00% Second-Priority Senior Secured Notes—due April 2022 — The 11.00% Notes were issued pursuant to an indenture dated May 10, 2018, between the Talos Issuers, the subsidiary guarantors party thereto and Wilmington Trust, National Association, as trustee and collateral agent. The 11.00% Notes mature April 3, 2022 and have interest payable semi-annually each April 15 and October 15.

On June 15, 2020, the Company entered into an exchange agreement pursuant to which the Company agreed to exchange $37.2 million aggregate principal amount of the 11.00% Notes from certain holders in exchange for 3.1 million shares of the Company's common stock plus cash in an amount equal to accrued interest up to the June 18, 2020 settlement date. Additionally, during the year ended December 31, 2020, the Company repurchased $6.4 million of the 11.00% Notes. The exchange agreement and debt repurchases resulted in a gain on extinguishment of debt for the year ended December 31, 2020 of $1.7 million, which is presented as "Other income (expense)" on our Consolidated Statements of Operations.

7.50% Senior Notes—due May 2022 — The 7.50% Notes represent the remaining $6.1 million of long-term debt assumed in the Stone Combination that were not exchanged for 11.00% Notes pursuant to the exchange offer and consent solicitation, and thus remain outstanding. As a result of the exchange offer and consent solicitation, substantially all of the restrictive covenants relating to the 7.50% Notes have been removed and collateral securing the 7.50% Notes has been released. The 7.50% Notes mature May 31, 2022 and have interest payable semiannually each May 31 and November 30.

Performance Bonds — As of December 31, 2020, we had secured performance bonds primarily related to plugging and abandonment of wells and removal of facilities in the U.S. Gulf of Mexico and to guarantee the completion of the minimum work program under the Mexico production sharing contracts totaling approximately $651.8 million. In 2016, the BOEM under the Obama Administration issued the 2016 NTL to clarify the procedures and guidelines that BOEM Regional Directors use to determine if and when additional financial assurances may be required for OCS leases, ROWs and RUEs. The 2016 NTL, which bolstered supplemental bonding requirements, became effective in September 2016, but was not fully implemented as the BOEM under the Trump Administration first paused, and then in 2020 rescinded, the implementation of this NTL while the BOEM and BSEE issued a jointly proposed rulemaking in October 2020 in which BOEM proposed amendments to its financial assurance program. The October 2020 rulemaking proposes to clarify and provide greater transparency to decommissioning and related financial assurance requirements imposed on oil and gas lessees (record title owners), sublessees (operating rights owners) and RUE and ROW grant holders conducting operations on the federal OCS. However, with President Biden taking office in January 2021, it is possible that the new Administration will reconsider regulatory actions undertaken by the former Administration with respect to financial assurance requirements, including rescission of the 2016 NTL and publication of the October 2020 proposed rule, and may adopt and implement more stringent supplemental bonding requirements.

The future cost of compliance with respect to supplemental bonding, including the obligations imposed on us, whether as current or predecessor lessee or grant holder, as a result of the 2016 NTL, to the extent re-implemented or the October 2020 proposed rule, to the extent finalized, as well as to the provisions of any new, more stringent NTLs or final rules on supplemental bonding published by the BOEM under the Biden Administration, could materially and adversely affect our financial condition, cash flows and results of operations. Moreover, the BOEM has the right to issue liability orders in the future, including if it determines there is a substantial risk of nonperformance of the interest holder's decommissioning liabilities.

Off Balance Sheet Arrangements

We did not have any off balance sheet arrangements as of December 31, 2020.

Contractual Obligations

We are party to various contractual obligations. Some of these obligations may be reflected in our accompanying Consolidated Financial Statements, while other obligations, such as certain operating leases and capital commitments, are not reflected on our accompanying Consolidated Financial Statements.

The following table and discussion summarizes our contractual cash obligations as of December 31, 2020 (in thousands):

	2021	2022	2023	2024	Thereafter	Total(5)
Long-term financing obligations:						
Debt Principal(1)	$ —	$ 993,314	$ —	$ —	$ —	$ 993,314
Debt Interest(1)	64,136	19,083	—	—	—	83,219
Vessel Commitments(2)	800	—	—	—	—	800
Derivative liabilities	66,010	9,625	—	—	—	75,635
Operating Lease Obligations	4,079	4,302	4,239	3,315	15,790	31,725
Capital lease(3)	45,000	45,000	18,750	—	—	108,750
Purchase Obligations(4)	2,165	—	—	—	—	2,165
Other Liabilities	7,921	—	—	—	—	7,921
Total contractual obligations(5)	$190,111	$1,071,324	$ 22,989	$ 3,315	$ 15,790	$1,303,529

(1) During January 2021, we redeemed the aggregate principal amount of the 11.00% Notes and partially repaid the outstanding borrowings under the Bank Credit Facility. See Part II, Item 7. Management Discussion and Analysis of Financial Condition and Results of Operations — *Recent Developments* for additional information.

(2) Includes vessel commitments we will utilize for certain deep water well intervention and decommissioning activities. These commitments represent gross contractual obligations and accordingly, other joint owners in the properties operated by us will be billed for their working interest share of such costs. Includes commitments for drilling rigs we will utilize for certain deep water well intervention and decommissioning activities.

(3) Lease agreement for the HP-I floating production facility in the Phoenix Field.

(4) Includes committed purchase orders to execute planned future drilling and completion activities.

(5) This table does not include our estimated discounted liability for dismantlement, abandonment and restoration costs of oil and natural gas properties of $442.3 million as of December 31, 2020. For additional information regarding these liabilities, please see Part IV, Item 15. Exhibits, Financial Statement Schedules — Note 4 — *Property, Plant and Equipment*.

Performance Bonds — As of December 31, 2020 and 2019, we had secured performance bonds primarily related to P&A of wells and removal of facilities and executing the minimum work program under the PSCs totaling approximately $651.8 million and $637.3 million, respectively. As of December 31, 2020 and 2019, we had $13.6 million and $13.6 million, respectively, in letters of credit issued under our Bank Credit Facility and our previous credit facility primarily for the P&A of wells and the removal of facilities.

For additional information about certain of our obligations and contingencies, see Part IV, Item 15. Exhibits, Financial Statement Schedules — Note 12 — *Commitments and Contingencies*.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with GAAP requires our management to make estimates and assumptions that affect the reported amount of assets, liabilities, revenue and expense, and the disclosures of contingent assets and liabilities. We consider our critical accounting estimates to be those estimates that require complex or subjective judgment in the application of the accounting policy and that could significantly impact our financial results based on changes in those judgments. Changes in facts and circumstances may result in revised estimates and actual results may differ materially from those estimates. Our management has identified the following critical accounting estimates. Our significant accounting policies are described in Part IV, Item 15. Exhibits, Financial Statement Schedules — Note 2 — *Summary of Significant Accounting Policies*.

Oil and Natural Gas Properties — The Company follows the full cost method of accounting for oil and natural gas exploration and development activities. Under the full cost method, substantially all costs incurred in connection with the acquisition, development and exploration of oil and natural gas reserves are capitalized. These capitalized amounts include the internal costs directly related to acquisition, development and exploration activities, asset retirement costs and capitalized interest. Under the full cost method, dry hole costs and geological and geophysical costs are capitalized into the full cost pool, which is subject to amortization and assessed for impairment on a quarterly basis through a ceiling test calculation as discussed below.

Capitalized costs associated with proved reserves are amortized on a country by country basis over the life of the total proved reserves using the unit of production method, computed quarterly. Conversely, capitalized costs associated with unproved properties and related geological and geophysical costs, exploration wells currently drilling and capitalized interest are initially excluded from the amortizable base. The Company transfers unproved property costs into the amortizable base when properties are determined to have proved reserves or when the Company has completed an unproved properties evaluation resulting in an impairment. The Company evaluates each of these unproved properties individually for impairment at least quarterly. Additionally, the amortizable base includes future development costs, dismantlement, restoration and abandonment costs, net of estimated salvage values, and geological and geophysical costs incurred that cannot be associated with specific unproved properties or prospects in which the Company owns a direct interest. The Company capitalizes overhead costs that are directly related to exploration, acquisition and development activities.

The Company's capitalized costs are limited to a ceiling based on the present value of future net revenues from proved reserves, computed using a discount factor of 10 percent, plus the lower of cost or estimated fair value of unproved oil and natural gas properties not being amortized less the related tax effects. Any costs in excess of the ceiling are recognized as a non-cash "Write-down of oil and natural gas properties" on the Consolidated Statements of Operations and an increase to "Accumulated depreciation, depletion and amortization" on the Company's Consolidated Balance Sheets. The expense may not be reversed in future periods, even though higher oil, natural gas and NGL prices may subsequently increase the ceiling. The Company performs this ceiling test calculation each quarter. In accordance with the SEC rules and regulations, the Company utilizes SEC Pricing when performing the ceiling test. The Company also holds prices and costs constant over the life of the reserves, even though actual prices and costs of oil and natural gas are often volatile and may change from period to period.

Under the full cost method of accounting for oil and natural gas operations, assets whose costs are currently being depreciated, depleted or amortized are assets in use in the earnings activities of the enterprise and do not qualify for capitalization of interest cost. Investments in unproved properties for which exploration and development activities are in progress and other major development projects that are not being currently depreciated, depleted or amortized are assets qualifying for capitalization of interest costs.

When the Company sells or conveys interests in oil and natural gas properties, the Company reduces its oil and natural gas reserves for the amount attributable to the sold or conveyed interest. The Company treats sales proceeds on non-significant sales as reductions to the cost of the Company's oil and natural gas properties. The Company does not recognize a gain or loss on sales of oil and natural gas properties, unless those sales would significantly alter the relationship between capitalized costs and proved reserves.

Proved Reserve Estimates — We estimate our proved oil, natural gas and NGL reserves in accordance with the guidelines established by the SEC. Proved oil, natural gas and NGL reserves are those quantities of oil, natural gas and NGLs, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible in future periods from known reservoirs and under existing economic conditions, operating methods and governmental regulations. Prices are determined using SEC pricing.

Our estimates of proved reserves are made using available geological and reservoir data, as well as production performance data. The estimates of proved reserves are reviewed annually by internal reservoir engineers and revised, either upward or downward, as warranted by additional data. Revisions are necessary due to changes in, among other things, reservoir performance, prices, economic conditions and governmental restrictions. Decreases in price, for example, may cause a reduction in some proved reserves due to reaching economic limits at an earlier projected date. A material adverse change in the estimated volumes of proved reserves could have a negative impact on depreciation, depletion and amortization or could result in property impairments.

Fair Value Measure of Financial Instruments — Our financial instruments generally consisted of cash and cash equivalents, restricted cash, accounts receivable, commodity derivatives, accounts payable and debt as of December 31, 2020. The carrying amount of cash and cash equivalents, restricted cash, accounts receivable and accounts payable approximates fair value due to the highly liquid nature of these instruments.

Fair value accounting standards define fair value, establish a consistent framework for measuring fair value and stipulate the related disclosure requirements for each major asset and liability category measured at fair value on either a recurring or nonrecurring basis. These standards also clarify fair value as an exit price, presenting the amount that would be received to sell an asset or paid to transfer a liability, in an orderly transaction between market participants. We follow a three-level hierarchy, prioritizing and defining the types of inputs used to measure fair value depending on the degree to which they are observable as follows:

Level 1 — Inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.

Level 2 — Inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial statement.

Level 3 — Inputs to the valuation methodology are unobservable (little or no market data), which require us to develop our own assumptions, and are significant to the fair value measurement.

Assets and liabilities measured at fair value are based on one or more of three valuation techniques. The valuation techniques are as follows:

Market Approach — Prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities.

Cost Approach — Amount that would be required to replace the service capacity of an asset (replacement cost).

Income Approach — Techniques to convert expected future cash flows to a single present value amount based on market expectations (including present value techniques, option-pricing and excess earnings models).

Authoritative guidance on financial instruments requires certain fair value disclosures to be presented. The estimated fair value amounts have been determined using available market information and valuation methodologies. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

Asset Retirement Obligations — The Company has obligations associated with the retirement of its oil and natural gas wells and related infrastructure. The Company has obligations to plug wells when production on those wells is exhausted, when the Company no longer plans to use them or when the Company abandons them. The Company accrues a liability with respect to these obligations based on its estimate of the timing and amount to replace, remove or retire the associated assets.

In estimating the liability associated with its asset retirement obligations, the Company utilizes several assumptions, including a credit-adjusted risk-free interest rate, estimated costs of decommissioning services, estimated timing of when the work will be performed and a projected inflation rate. Changes in estimate in the table below represent changes to the expected amount and timing of payments to settle its asset retirement obligations. Typically, these changes result from obtaining new information about the timing of its obligations to plug and abandon oil and natural gas wells and the costs to do so. After initial recording, the liability is increased for the passage of time, with the increase being reflected as “Accretion expense” in the Company’s Consolidated Statements of Operations. If the Company incurs an amount different from the amount accrued for decommissioning obligations, the Company recognizes the difference as an adjustment to proved properties.

Revenue Recognition, Imbalances and Production Handling Fees — *R*evenues are recorded based from the sale of oil, natural gas and NGLs based on quantities of production sold to purchasers under short-term contracts (less than twelve months) at market prices when delivery to the customer has occurred, title has transferred, prices are fixed and determinable and collection is reasonably assured. This occurs when production has been delivered to a pipeline or when a barge lifting has occurred.

Revenues are recorded based on the actual sales volumes sold to purchasers. An imbalance receivable or payable is recorded only to the extent the imbalance is in excess of its share of remaining proved developed reserves in an underlying property. The change in accounting method from the entitlements method to the sales method resulted in an immaterial cumulative-effect adjustment to members’ deficit on the date of adoption. Our imbalances are recorded gross on our Consolidated Balance Sheets. At December 31, 2020 and 2019, our imbalance receivable was approximately $1.7 million and $1.7 million, respectively, and imbalance payable was approximately $3.6 million and $3.6 million, respectively.

Income Taxes — Our provision for income taxes includes U.S. state and federal and foreign taxes. We record our federal income taxes in accordance with accounting for income taxes under GAAP which results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the book carrying amounts and the tax basis of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized. As of December 31, 2020, we believe it is more likely than not that some or all of the benefits from our federal and state deferred tax assets will not be realized and reduced the net federal and state deferred tax assets by a valuation allowance. We maintain a valuation allowance on most of our Mexico deferred tax assets.

We apply significant judgment in evaluating our tax positions and estimating our provision for income taxes. During the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. The actual outcome of these future tax consequences could differ significantly from our estimates, which could impact our financial position, results of operations and cash flows.

We also account for uncertainty in income taxes recognized in the financial statements in accordance with GAAP by prescribing a recognition threshold and measurement attribute for a tax position taken or expected to be taken in a tax return. Authoritative guidance for accounting for uncertainty in income taxes requires that we recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more likely than not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with the relevant tax authority.

Recently Adopted Accounting Standards

See Part IV, Item 15. Exhibits, Financial Statement Schedules — Note 1 — *Formation and Basis of Presentation* to the Consolidated Financial Statements included elsewhere in this Annual Report for our Recently Adopted Accounting Standards.

Recently Issued Accounting Standards

See Part IV, Item 15. Exhibits, Financial Statement Schedules — Note 1 — *Formation and Basis of Presentation* to the Consolidated Financial Statements included elsewhere in this Annual Report for Recently Issued Accounting Standards applicable to us.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are currently exposed to market risk in two areas: commodity prices and, to a lesser extent, interest rate risk. Our risk management activities involve the use of derivative financial instruments to mitigate the impact of market price risk exposures primarily related to our oil and natural gas production. All derivatives are recorded on the Consolidated Balance Sheets at fair value with settlements of such contracts and changes in the unrealized fair value recorded as "Price risk management activities income (expense)" on the Consolidated Statements of Operations in each period.

Commodity Price Risks

Oil and natural gas prices can fluctuate significantly and have a direct impact on our revenues, earnings and cash flow. During year ended December 31, 2020, our average oil price realizations after the effect of derivatives decreased 20% to $47.36 per Bbl from $59.23 per Bbl in the comparable 2019 period. Our average natural gas price realizations after the effect of derivatives decreased 22% during the year ended December 31, 2020 to $2.00 per Mcf from $2.55 per Mcf in the comparable 2019 period.

Price Risk Management Activities

We have attempted to mitigate commodity price risk and stabilize cash flows associated with our forecasted sales of oil and natural gas production through the use of oil and natural gas swaps. These contracts will impact our earnings as the fair value of these derivatives changes. Our derivatives will not mitigate all of the commodity price risks of our forecasted sales of oil and natural gas production and, as a result, we will be subject to commodity price risks on our remaining forecasted production.

We had commodity derivative instruments in place to reduce the price risk associated with future production of 13,711 MBbls of crude oil and 35,053 MMBtu of natural gas at December 31, 2020, with a net derivative liability position of $67.8 million. For additional information regarding our commodity derivative instruments, see Part IV, Item 15. Exhibits, Financial Statement Schedules — Note 6 — *Financial Instruments*, included elsewhere in this Annual Report. The table below presents the hypothetical sensitivity of our commodity price risk management activities to changes in fair values arising from immediate selected potential changes in oil and natural gas prices at December 31, 2020 (in thousands):

		Oil and Natural Gas Derivatives			
		10 Percent Increase		10 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
Price impact[(1)]	$ (67,814)	$(141,066)	$ (73,252)	$ 5,371	$ 73,185

(1) Presents the hypothetical sensitivity of our commodity price risk management activities to changes in fair values arising from changes in oil and natural gas prices.

Variable Interest Rate Risks

We had total debt outstanding of $993.3 million at December 31, 2020, before unamortized original issue discount and deferred financing costs. Of this, $353.3 million aggregate principal was from our 11.00% Notes and 7.50% Notes, which bear interest at fixed rates. The remaining $640.0 million is from outstanding borrowings under our Bank Credit Facility with variable interest rates. We are subject to the risk of changes in interest rates under our Bank Credit Facility. In addition, the terms of our Bank Credit Facility require us to pay higher interest rates as we utilize a larger percentage of our available borrowing base. We manage our interest rate exposure by maintaining a combination of fixed and variable rate debt and monitoring the effect of market changes in interest rates. We believe our interest rate risk exposure is partially mitigated as a result of fixed interest rates on 35% of our debt. The interest rate on our variable rate debt at December 31, 2020 was 3.65%. A 10% change in the interest rate on this variable rate debt balance at December 31, 2020 would change interest expense for the year ended December 31, 2020 by approximately $0.1 million.

Item 8. Financial Statements and Supplementary Data

See the Consolidated Financial Statements and Report of Independent Registered Public Accounting Firm as of December 31, 2020 and 2019 and for the years ended December 31, 2020, 2019 and 2018, included in Part IV, Item 15. Exhibits, Financial Statements Schedules.

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

Our management, with the participation of our chief executive officer and chief financial officer, has evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a- 15(e) and 15d- 15(e) under the Exchange Act) as of the end of the period covered by this Annual Report on Form 10-K. Based on such evaluation, our chief executive officer and chief financial officer have concluded that as of December 31, 2020, our disclosure controls and procedures are designed at a reasonable assurance level and are effective to provide reasonable assurance that information we are required to disclose in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of SEC, and that such information is accumulated and communicated to our management, including our chief executive officer and chief financial officer, as appropriate, to allow timely decisions regarding required disclosures.

Management's Annual Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) under the Exchange Act. Management conducted an assessment of the effectiveness of our internal control over financial reporting based on the criteria set forth in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework). Based on the assessment, management has concluded that its internal control over financial reporting was effective as of December 31, 2020 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with GAAP. Our independent registered public accounting firm, Ernst & Young LLP, has issued an audit report with respect to our internal control over financial reporting, which is included in this Annual Report on Form 10-K.

Changes in Internal Control over Financial Reporting

There were no changes in our internal controls over financial reporting identified in management's evaluation pursuant to Rules 13a-15(d) or 15d-15(d) of the Exchange Act during the fourth quarter of 2020 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

The information required by this item is incorporated by reference to our Proxy Statement for the 2021 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2020.

Our board of directors has adopted a Code of Business Conduct and Ethics applicable to all officers, directors and employees, which is available on our website (*www.talosenergy.com*) under “Corporate Governance and Board Committees.” We intend to satisfy the disclosure requirement under Item 5.05 of Form 8-K regarding amendment to, or waiver from, a provision of our Code of Business Conduct and Ethics by posting such information on the website address and location specified above.

Item 11. Executive Compensation

The information required by this item is incorporated by reference to our Proxy Statement for the 2021 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2020.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

The information required by this item is incorporated by reference to our Proxy Statement for the 2021 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2020.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required by this item is incorporated by reference to our Proxy Statement for the 2021 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2020.

Item 14. Principal Accounting Fees and Services

The information required by this item is incorporated by reference to our Proxy Statement for the 2021 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2020.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) 1 **Financial Statements**

Refer to the Index to Consolidated Financial Statements on page F-1 for a list of all financial statements filed as part of this Annual Report on Form 10-K.

(a) 2 **Financial Statement Schedules**

Financial statement schedules have been omitted because they are either not required, not applicable or the information required to be presented is included in our Consolidated Financial Statements and related notes.

(a) 3 **Exhibits:**

Exhibit Number	Description
2.1#	Transaction Agreement, dated as of November 21, 2017, by and among Stone Energy Corporation, Sailfish Energy Holdings Corporation, Sailfish Merger Sub Corporation, Talos Energy LLC and Talos Production LLC (incorporated by reference to Exhibit 2.1 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
2.2#	Purchase and Sale Agreement, dated as of December 10, 2019, by and among Talos Energy Inc., Talos Production Inc. and ILX Holdings, LLC (incorporated by reference to Exhibit 2.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on December 16, 2019).
2.3	Amendment to Purchase and Sale Agreement, dated as of February 24, 2020, by and among Talos Energy Inc., Talos Production Inc. and ILX Holdings LLC (incorporated by reference to Exhibit 2.2 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on February 25, 2020).
2.4#	Purchase and Sale Agreement, dated as of December 10, 2019, by and among Talos Energy Inc., Talos Production Inc. and ILX Holdings II, LLC (incorporated by reference to Exhibit 2.2 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on December 16, 2019).
2.5	Amendment to Purchase and Sale Agreement, dated as of February 24, 2020, by and among Talos Energy Inc., Talos Production Inc. and ILX Holdings II LLC (incorporated by reference to Exhibit 2.4 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on February 25, 2020).
2.6#	Purchase and Sale Agreement, dated as of December 10, 2019, by and among Talos Energy Inc., Talos Production Inc. and ILX Holdings III LLC (incorporated by reference to Exhibit 2.3 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on December 16, 2019).
2.7	Amendment to Purchase and Sale Agreement, dated as of February 24, 2020, by and among Talos Energy Inc., Talos Production Inc. and ILX Holdings III LLC (incorporated by reference to Exhibit 2.6 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on February 25, 2020).
2.8#	Purchase and Sale Agreement, dated as of December 10, 2019, by and among Talos Energy Inc., Talos Production Inc. and Castex Energy 2014, LLC (incorporated by reference to Exhibit 2.4 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on December 16, 2019).
2.9	Amendment to Purchase and Sale Agreement, dated as of February 24, 2020, by and among Talos Energy Inc., Talos Production Inc. and Castex Energy 2014, LLC (incorporated by reference to Exhibit 2.8 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on February 25, 2020).
2.10#	Purchase and Sale Agreement, dated as of December 10, 2019, by and among Talos Energy Inc., Talos Production Inc. and Castex Energy 2016, LP (incorporated by reference to Exhibit 2.5 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on December 16, 2019).
3.1	Amended and Restated Certificate of Incorporation of Talos Energy Inc. (incorporated by reference to Exhibit 3.1 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).

Exhibit Number	Description
3.2	Amended and Restated Bylaws of Talos Energy Inc. (incorporated by reference to Exhibit 3.2 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
3.3	Certificate of Designation, dated as of February 27, 2020 (incorporated by reference to Exhibit 3.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on March 2, 2020).
4.1	Form of Stock Certificate for Common Stock of Talos Energy Inc. (incorporated by reference to Exhibit 4.2 to Talos Energy Inc.'s Amendment No. 1 to the Registration Statement on Form S-4 (File No. 333-222341) filed with the SEC on February 9, 2018).
4.2	Indenture, dated as of May 10, 2018, by and among Talos Production LLC, Talos Production Finance, Inc., the subsidiary guarantors party thereto and Wilmington Trust, National Association, as trustee and collateral agent (incorporated by reference to Exhibit 4.5 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
4.3	Supplemental Indenture No. 1, dated as of September 12, 2018, by and among Talos Production LLC, Talos Production Finance, Inc., Talos Energy Inc. and Wilmington Trust, National Association, as trustee and collateral agent. (incorporated by reference to Exhibit 4.2 to Talos Energy Inc.'s Registration Statement on Form S-4 (File No. 333-227362) filed with the SEC on September 14, 2018).
4.4	Registration Rights Agreement, dated as of May 10, 2018, by and among Talos Production LLC, Talos Production Finance, Inc., the subsidiary guarantors named therein and each of the holders set forth on the signature pages thereto (incorporated by reference to Exhibit 4.6 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
4.5	Form of 11.00% Second-Priority Senior Secured Note due 2022 (included in Exhibit 4.2).
4.6	Indenture, dated as of January 4, 2021, by and among Talos Production Inc., the Guarantors named therein and Wilmington Trust, National Association, as trustee and as collateral agent (incorporated by reference to Exhibit 4.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on January 8, 2021).
4.7	First Supplemental Indenture, dated as of January 14, 2021, by and among Talos Production Inc., the Guarantors named therein and Wilmington Trust, National Association, as trustee and as collateral agent (incorporated by reference to Exhibit 4.3 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on January 14, 2021).
4.8	Form of 12.00% Second-Priority Senior Secured Note due 2026 (included as Exhibit A to Exhibit 4.6 hereto) (incorporated by reference to Exhibit 4.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on January 8, 2021).
4.9	Registration Rights Agreement, dated as of January 4, 2021, by and among Talos Production Inc., the Guarantors named therein and J.P. Morgan Securities LLC, as representative of the initial purchasers of the 2026 Notes (incorporated by reference to Exhibit 4.3 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on January 8, 2021).
4.10	Registration Rights Agreement, dated as of January 14, 2021, by and among Talos Production Inc., the Guarantors named therein and J.P. Morgan Securities LLC, as representative of the initial purchasers of the 2026 Notes (incorporated by reference to Exhibit 4.4 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on January 14, 2021).
4.11	Stockholders' Agreement, dated as of May 10, 2018, by and among Talos Energy Inc. and each of the other parties set forth on the signature pages thereto (incorporated by reference to Exhibit 4.1 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
4.12	Stockholders' Agreement Amendment, dated as of February 24, 2020, by and among Talos Energy Inc. and each of the other parties set forth on the signature pages thereto (incorporated by reference to Exhibit 4.2 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on February 25, 2020).

Exhibit Number	Description
4.13	Registration Rights Agreement, dated as of May 10, 2018, by and among Talos Energy Inc. and each of the other parties set forth on the signature pages thereto (incorporated by reference to Exhibit 4.2 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
4.14	Registration Rights Agreement Amendment, dated as of February 28, 2020, by and among Talos Energy Inc. and each of the other parties set forth on the signature pages thereto (incorporated by reference to Exhibit 4.2 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on March 2, 2020).
4.15	Warrant Agreement, dated as of February 28, 2017, by and among Stone Energy Corporation, Computershare Inc. and Computershare Trust Company, N.A. (incorporated by reference to Exhibit 4.3 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
4.16	Amendment No. 1 to Warrant Agreement, dated as of May 10, 2018, by and among Talos Energy Inc., Stone Energy Corporation, Computershare Inc. and Computershare Trust Company, N.A. (incorporated by reference to Exhibit 4.4 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
4.17	Description of Registrant's Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934 (incorporated by reference to Exhibit 4.12 to Talos Energy Inc.'s Form 10-K (File No. 001-38497) filed with the SEC on March 12, 2020).
10.1	Credit Agreement, dated as of May 10, 2018, by and among Talos Production LLC, as borrower, Talos Energy Inc., as holdings, JPMorgan Chase Bank, N.A., as administrative agent, and the lenders named therein (incorporated by reference to Exhibit 10.2 to Talos Energy Inc.'s Form 8-K12B/A filed with the SEC on July 18, 2018).
10.2	Intercreditor Agreement, dated as of May 10, 2018, between JPMorgan Chase Bank, N.A., as First Lien Agent, and Wilmington Trust, National Association, as Second Lien Agent (incorporated by reference to Exhibit 10.3 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
10.3†	Separation and Release Agreement, dated as of January 22, 2020, between Stephen E. Heitzman and Talos Energy Operating Company LLC (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on January 23, 2020).
10.4†	Transition, Separation and Release Agreement between Michael L. Harding II and Talos Energy Operating Company LLC, dated as of June 18, 2019 (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 8-K filed with the SEC on June 19, 2019).
10.5†	Offer Letter between Talos Energy Inc. and Shannon Young, dated as of April 13, 2019 (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 8-K filed with the SEC on April 24, 2019).
10.6†	Offer Letter between Talos Energy Inc. and Robert D. Abendschein, dated as of December 26, 2019 (incorporated by reference to Exhibit 10.2 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on January 23, 2020).
10.7†	Employment Agreement, dated as of February 3, 2012, by and between Talos Energy Operating Company LLC and Timothy S. Duncan (incorporated by reference to Exhibit 10.10 to Talos Energy Inc.'s Amendment No. 3 to the Registration Statement on Form S-4 (File No. 333-222341) filed with the SEC on March 30, 2018).
10.8†	Employment Agreement, dated as of February 3, 2012, by and between Talos Energy Operating Company LLC and Stephen E. Heitzman (incorporated by reference to Exhibit 10.11 to Talos Energy Inc.'s Amendment No. 3 to the Registration Statement on Form S-4 (File No. 333-222341) filed with the SEC on March 30, 2018).

Exhibit Number	Description
10.9†	Employment Agreement, dated as of February 3, 2012, by and between Talos Energy Operating Company LLC and John A. Parker (incorporated by reference to Exhibit 10.12 to Talos Energy Inc.'s Amendment No. 3 to the Registration Statement on Form S-4 (File No. 333-222341) filed with the SEC on March 30, 2018).
10.10†	Employment Agreement, dated as of March 14, 2016, by and between Talos Energy Operating Company LLC and Michael L. Harding II (incorporated by reference to Exhibit 10.13 to Talos Energy Inc.'s Amendment No. 3 to the Registration Statement on Form S-4 (File No. 333-222341) filed with the SEC on March 30, 2018).
10.11†	Employment Agreement, dated as of August 30, 2013, by and between Talos Energy Operating Company LLC and William S. Moss III (incorporated by reference to Exhibit 10.14 to Talos Energy Inc.'s Amendment No. 3 to the Registration Statement on Form S-4 (File No. 333-222341) filed with the SEC on March 30, 2018).
10.12†	Talos Energy Inc. Long Term Incentive Plan (incorporated by reference to Exhibit 10.4 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
10.13	Support Agreement, dated as of November 21, 2017, by and among Stone Energy Corporation, Sailfish Energy Holdings Corporation, Apollo Management VII, L.P., Apollo Commodities Management, L.P., with respect to Series I, and Riverstone Energy Partners V, L.P. (incorporated by reference to Exhibit 10.3 to Talos Energy Inc.'s Amendment No. 1 to the Registration Statement on Form S-4 (File No. 333-222341) filed with the SEC on February 9, 2018).
10.14	Exchange Agreement, dated as of November 21, 2017, by and among Talos Production LLC, Talos Production Finance Inc., Stone Energy Corporation, Sailfish Energy Holdings Corporation and the lenders and noteholders listed on the schedules thereto (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
10.15	Contract for the Exploration and Extraction of Hydrocarbons under Production Sharing Modality (Contract Area 2), dated as of September 4, 2015, by and among the National Hydrocarbons Commission, Sierra O&G Exploración y Producción, S. de R.L. de C.V., Talos Energy Offshore México 2, S. de R.L. de C.V. and Premier Oil Exploration and Production Mexico, S.A. de C.V. (incorporated by reference to Exhibit 10.8 to Talos Energy Inc.'s Amendment No. 2 to the Registration Statement on Form S-4 (File No. 333-222341) filed with the SEC on March 15, 2018).
10.16	Contract for the Exploration and Extraction of Hydrocarbons under Production Sharing Modality (Contract Area 7), dated as of September 4, 2015, by and among the National Hydrocarbons Commission, Sierra O&G Exploración y Producción, S. de R.L. de C.V., Talos Energy Offshore México 7, S. de R.L. de C.V. and Premier Oil Exploration and Production Mexico, S.A. de C.V. (incorporated by reference to Exhibit 10.9 to Talos Energy Inc.'s Amendment No. 4 to the Registration Statement on Form S-4 (File No. 333-222341) filed with the SEC on April 4, 2018).
10.17†	Indemnification Agreement (Timothy S. Duncan) (incorporated by reference to Exhibit 10.5 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
10.18†	Indemnification Agreement (Stephen E. Heitzman) (incorporated by reference to Exhibit 10.6 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
10.19†	Indemnification Agreement (John A. Parker) (incorporated by reference to Exhibit 10.7 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
10.20†	Indemnification Agreement (Michael L. Harding II) (incorporated by reference to Exhibit 10.8 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
10.21†	Indemnification Agreement (William S. Moss III) (incorporated by reference to Exhibit 10.9 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).

Exhibit Number	Description
10.22†	Indemnification Agreement (Olivia C. Wassenaar) (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 8-K filed with the SEC on November 23, 2018).
10.23†	Indemnification Agreement (Christine Hommes) (incorporated by reference to Exhibit 10.11 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
10.24†	Indemnification Agreement (Robert M. Tichio) (incorporated by reference to Exhibit 10.12 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
10.25†	Indemnification Agreement (Neal P. Goldman) (incorporated by reference to Exhibit 10.14 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
10.26†	Indemnification Agreement (John "Brad" Juneau) (incorporated by reference to Exhibit 10.15 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
10.27†	Indemnification Agreement (James M. Trimble) (incorporated by reference to Exhibit 10.16 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
10.28†	Indemnification Agreement (Charles M. Sledge) (incorporated by reference to Exhibit 10.17 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
10.29†	Indemnification Agreement (Donald R. Kendall, Jr.) (incorporated by reference to Exhibit 10.18 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
10.30†	Indemnification Agreement (Rajen Mahagaokar) (incorporated by reference to Exhibit 10.19 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
10.31†	Indemnification Agreement (Shannon E. Young III), effective as of May 16, 2019 (incorporated by reference to Exhibit 10.2 to Talos Energy Inc.'s Form 8-K filed with the SEC on April 24, 2019).
10.32†	Indemnification Agreement (Robert D. Abendschein) (incorporated by reference to Exhibit 10.3 to Talos Energy Inc.'s Form 8-K filed with the SEC on January 23, 2020).
10.33†	Form of Restricted Stock Unit Grant Notice and Restricted Stock Agreement (Directors) (incorporated by reference to Exhibit 10.20 to Talos Energy Inc.'s Form 10-Q filed with the SEC on August 9, 2018).
10.34†	Form of Restricted Stock Unit Grant Notice and Restricted Stock Unit Agreement (Executives) (incorporated by reference to Exhibit 10.32 to Talos Energy Inc.'s Registration Statement on Form S-4 (File No. 333-227362) filed with the SEC on September 14, 2018)
10.35†	Form of Performance Share Unit Grant Notice and Performance Share Unit Agreement (Executives) (incorporated by reference to Exhibit 10.33 to Talos Energy Inc.'s Registration Statement on Form S-4 (File No. 333-227362) filed with the SEC on September 14, 2018).
10.36†	Talos Energy Operating Company LLC Executive Severance Plan (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 8-K filed with the SEC on September 5, 2018).
10.37†	Form of Participation Agreement pursuant to the Talos Energy Operating Company LLC Executive Severance Plan (incorporated by reference to Exhibit 10.2 to Talos Energy Inc.'s Form 8-K filed with the SEC on September 5, 2018).
10.38	First Amendment Agreement to the Contract for the Exploration and Extraction of Hydrocarbons in the Form of Shared Production, dated as of August 8, 2018, between the National Hydrocarbons Commission and Talos Energy Offshore México 2, S. de R.L. de C.V., Premier Oil Exploration and Production México, S.A. de C.V., and Sierra Blanca P&D, S. de R.L. de C.V. (incorporated by reference to Exhibit 10.34 to Talos Energy Inc.'s Form 10-K (File No. 01-38497) filed with the SEC on March 13, 2019).

Exhibit Number	Description
10.39	Second Amendment Agreement to the Contract for the Exploration and Extraction of Hydrocarbons in the Form of Shared Production, dated as of December 20, 2018, between the National Hydrocarbons Commission and Hokchi Energy, S.A. de C.V., Sierra Blanca P&D, S. de R.L. de C.V., Talos Energy Offshore México 2, S. de R.L. de C.V., and Premier Oil Exploration and Production México, S.A. de C.V. (incorporated by reference to Exhibit 10.35 to Talos Energy Inc.'s Form 10-K (File No. 01-38497) filed with the SEC on March 13, 2019).
10.40	Joinder, First Amendment to Credit Agreement, and Borrowing Base Reaffirmation Agreement, dated as of July 3, 2019, by and among Talos Energy Inc., as holdings, Talos Production LLC, as borrower, each other credit party, JPMorgan Chase Bank, N.A., as administrative agent, each issuing bank, the swingline lender, and the lenders (including the new lenders) party thereto (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 8-K filed with the SEC on July 10, 2019).
10.41	Joinder, Commitment Increase Agreement, Second Amendment to Credit Agreement, Borrowing Base Redetermination Agreement, and Amendment to Other Credit Documents, dated as of December 10, 2019, by and among Talos Energy Inc., as holdings, Talos Production Inc., as borrower, each other credit party, JPMorgan Chase Bank, N.A., as administrative agent, each issuing bank, the swingline lender, and the lenders (including the new lenders) party thereto (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on December 16, 2019).
10.42	Third Amendment to Credit Agreement and Borrowing Base Redetermination Agreement, dated as of June 19, 2020, by and among Talos Energy Inc., as holdings, Talos Production Inc., as borrower, each other credit party, JPMorgan Chase Bank, N.A., as administrative agent, each issuing bank, the swing line lender, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on June 25, 2020).
10.43†	Talos Energy Operating Company LLC Amended and Restated Executive Severance Plan (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on March 2, 2020).
10.44†	Form of Participation Agreement pursuant to Talos Energy Operating Company LLC Amended and Restated Executive Severance Plan (incorporated by reference to Exhibit 10.2 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on October 26, 2020).
21.1*	List of Subsidiaries of Talos Energy Inc.
23.1*	Consent of Ernst & Young LLP.
23.2*	Consent of Netherland, Sewell & Associates, Inc.
24.1*	Powers of Attorney (included on signature pages of this Part IV)
31.1*	Certification of Chief Executive Officer of Talos Energy Inc. pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer of Talos Energy Inc. pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of Chief Executive Officer and Chief Financial Officer of Talos Energy Inc. pursuant to 18 U.S.C. § 1350, as adopted pursuant to the Sarbanes-Oxley Act of 2002.
99.1*	Netherland, Sewell & Associates, Inc. reserve report for Talos Energy Inc. as of December 31, 2020.
99.2	Netherland, Sewell & Associates, Inc. reserve report for Talos Energy Inc. as of December 31, 2019 (incorporated by reference to Exhibit 99.1 to Talos Energy Inc.'s Form 10-K (File No. 001-38497) filed with the SEC on March 12, 2020).

Exhibit Number	Description
99.3	Netherland, Sewell & Associates, Inc. reserve report for Talos Energy Inc. as of December 31, 2018 (incorporated by reference to Exhibit 99.1 to Talos Energy Inc.'s Annual Report on Form 10-K (File No. 001-38497) filed with the SEC on March 13, 2019).
101.INS*	Inline XBRL Instance.
101.SCH*	Inline XBRL Taxonomy Extension Schema.
101.CAL*	Inline XBRL Taxonomy Extension Calculation.
101.DEF*	Inline XBRL Taxonomy Extension Definition.
101.LAB*	Inline XBRL Taxonomy Extension Label.
101.PRE*	Inline XBRL Taxonomy Extension Presentation.
104*	Cover Page Interactive Data File – The cover page interactive data file does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.

* Filed herewith.

** Furnished herewith.

† Identifies management contracts and compensatory plans or arrangements.

\# Certain schedules, annexes or exhibits have been omitted pursuant to Item 601(a)(5) of Regulation S-K, but will be furnished supplementally to the SEC upon request.

Item 16. Form 10-K Summary

None.

SIGNATURES

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

TALOS ENERGY INC.

Date:	March 10, 2021	By:	/s/ Shannon E. Young III
			Shannon E. Young III
			Executive Vice President and Chief Financial Officer

POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Timothy S. Duncan and Shannon E. Young III, and each of them, as his or her true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this report, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite and necessary to be done in connection therewith, as fully to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming that all said attorneys-in-fact and agents, or any of them or their or his or her substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Timothy S. Duncan Timothy S. Duncan	Chief Executive Officer (Principal Executive Officer, Director)	March 10, 2021
/s/ Shannon E. Young III Shannon E. Young III	Chief Financial Officer (Principal Financial Officer, Authorized Signatory)	March 10, 2021
/s/ Gregory Babcock Gregory Babcock	Chief Accounting Officer (Principal Accounting Officer, Authorized Signatory)	March 10, 2021
/s/ Rajen Mahagaokar Rajen Mahagaokar	Director	March 10, 2021
/s/ James M. Trimble James M. Trimble	Director	March 10, 2021
/s/ Olivia C. Wassenaar Olivia C. Wassenaar	Director	March 10, 2021
/s/ Christine Hommes Christine Hommes	Director	March 10, 2021
/s/ Neal P. Goldman Neal P. Goldman	Director	March 10, 2021
/s/ Charles M. Sledge Charles M. Sledge	Director	March 10, 2021
/s/ Robert M. Tichio Robert M. Tichio	Director	March 10, 2021
/s/ John “Brad” Juneau John “Brad” Juneau	Director	March 10, 2021
/s/ Donald R. Kendall, Jr. Donald R. Kendall, Jr.	Director	March 10, 2021

Index to Consolidated Financial Statements

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of
Talos Energy Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Talos Energy Inc. (the Company) as of December 31, 2020 and 2019, the related consolidated statements of operations, changes in stockholders' equity (deficit), and cash flows for each of the three years in the period ended December 31, 2020, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020, in conformity with U.S. generally accepted accounting principles.

We also have 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, 2020, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), and our report dated March 10, 2021 expressed an unqualified opinion thereon.

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 Matters

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 the critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing a separate opinion on the critical audit matters or on the accounts or disclosures to which they relate.

	Business Combination
Description of the Matter	As disclosed in Note 3 to the consolidated financial statements, the Company completed the acquisition of oil and gas properties in the Gulf of Mexico from ILX Holdings, LLC, ILX Holdings II, LLC, ILX Holdings III LLC, Castex Energy 2014, LLC, and Castex Energy 2016, LP (collectively, the "ILX and Castex Acquisition") for net consideration of $459.3 million. The transaction was accounted for as a business combination.

How We Addressed the Matter in Our Audit

We obtained an understanding, evaluated the design and tested the operating effectiveness of controls over the Company's accounting for acquisitions process, including management's controls over the completeness and accuracy of the financial data provided to the engineers for use in estimating oil and gas reserves.

Our audit procedures included, among others, evaluating the professional qualifications and objectivity of the Company's internal reservoir engineers primarily responsible for overseeing the preparation of the reserve estimates. In assessing whether we can use the work of the reservoir engineers. We also evaluated the completeness and accuracy of the financial data and inputs, described above, used by the engineers in estimating oil and gas reserves. For example, we agreed the financial data and inputs used to source documentation, and we identified and evaluated corroborative and contrary evidence. We involved our valuation specialists to assist with our testing of significant assumptions used in the fair value estimates, including, risk adjustment factors for oil and gas reserve classifications and the discount rate, discussed above. For example, we compared the significant assumptions used in the fair value estimates to current industry and economic trends as well as third party industry data.

Depreciation, depletion and amortization and write-down of oil and natural gas properties

Description of the Matter

At December 31, 2020, the carrying value of the Company's property and equipment was $2.5 billion, depreciation, depletion and amortization (DD&A) expense was $364.3 million and the write-down of oil and natural gas properties expense was $267.9 million for the year then ended. As described in Note 2, the Company follows the full cost method of accounting for its oil and gas properties. Pursuant to SEC Regulation S-X, Rule 4-10, under the full cost method of accounting, the Company's capitalized oil and natural gas costs are limited to a ceiling based on the present value of future net revenues from proved reserves, computed using a discount factor of 10%, plus the lower of cost or estimated fair value of unproved oil and natural gas properties not being amortized, less the related tax effects. The Company performs this ceiling test calculation each quarter utilizing SEC pricing. DD&A of the cost of proved oil and gas properties is calculated using the unit-of-production method based on proved oil and gas reserves, as estimated by the Company's internal reservoir engineers.

Proved oil and gas reserves are those quantities of natural gas, crude oil, condensate, and natural gas liquids, 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. Significant judgment is required by the Company's internal reservoir engineers in evaluating geological and engineering data when estimating oil and gas reserves. Estimating reserves also requires the selection of inputs, including oil and gas price assumptions, future operating and capital costs assumptions, among others. Because of the complexity involved in estimating oil and gas reserves, management engaged independent petroleum engineers to audit the proved oil and gas reserve estimates prepared by the Company's internal reservoir engineers for select properties as of December 31, 2020.

Auditing the Company's DD&A and write-down of oil and natural gas properties calculations is complex because of the use of the work of the internal reservoir engineers and independent petroleum engineers and the evaluation of management's determination of the inputs described above used by the engineers in estimating proved oil and gas reserves.

How We Addressed the Matter in Our Audit	We obtained an understanding, evaluated the design, and tested the operating effectiveness of the Company's controls over its process to calculate DD&A and write-down of oil and natural gas properties, including management's controls over the completeness and accuracy of the financial data provided to the engineers for use in estimating oil and gas reserves. Our audit procedures included, among others, evaluating the professional qualifications and objectivity of the Company's internal reservoir engineers primarily responsible for overseeing the preparation of the reserve estimates and the independent petroleum engineers used to audit the proved oil and gas reserve estimates. In addition, in assessing whether we can use the work of the engineers, we evaluated the completeness and accuracy of the financial data and inputs described above used by the engineers in estimating oil and gas reserves by agreeing them to source documentation, and we identified and evaluated corroborative and contrary evidence. For proved undeveloped reserves, we evaluated management's development plan for compliance with the SEC rule that undrilled locations are scheduled to be drilled within five years, unless specific circumstances justify a longer time, by assessing consistency of the development projections with the Company's development plan and the availability of capital relative to the development plan. We also tested the mathematical accuracy of the DD&A and write-down of oil and natural gas properties calculations, including comparing the oil and gas reserve amounts used in the calculations to the Company's reserve reports.

/s/ Ernst & Young LLP

We have served as the Company's auditor since 2010.

Houston, Texas
March 10, 2021

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of
Talos Energy Inc.

Opinion on Internal Control Over Financial Reporting

We have audited Talos Energy Inc.'s internal control over financial reporting as of December 31, 2020, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, Talos Energy Inc. (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2020, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2020 and 2019, the related consolidated statements of operations, changes in stockholders' equity (deficit) and cash flows for each of the three years in the period ended December 31, 2020, and the related notes (collectively referred to as the "consolidated financial statements") and our report dated March 10, 2021 expressed an unqualified opinion thereon.

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 Report of Management 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/ Ernst & Young LLP

Houston, Texas
March 10, 2021

TALOS ENERGY INC.
CONSOLIDATED BALANCE SHEETS
(In thousands, except share amounts)

	Year Ended December 31, 2020	Year Ended December 31, 2019
ASSETS		
Current assets:		
Cash and cash equivalents	$ 34,233	$ 87,022
Accounts receivable		
Trade, net	106,220	107,842
Joint interest, net	50,471	16,552
Other	18,448	6,346
Assets from price risk management activities	6,876	8,393
Prepaid assets	29,285	65,877
Other current assets	1,859	1,952
Total current assets	247,392	293,984
Property and equipment:		
Proved properties	4,945,550	4,066,260
Unproved properties, not subject to amortization	254,994	194,532
Other property and equipment	32,853	29,843
Total property and equipment	5,233,397	4,290,635
Accumulated depreciation, depletion and amortization	(2,697,228)	(2,065,023)
Total property and equipment, net	2,536,169	2,225,612
Other long-term assets:		
Assets from price risk management activities	945	—
Other well equipment inventory	18,927	7,732
Operating lease assets	6,855	7,779
Other assets	24,258	54,375
Total assets	$ 2,834,546	$ 2,589,482
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 104,864	$ 71,357
Accrued liabilities	163,379	154,816
Accrued royalties	27,903	31,729
Current portion of asset retirement obligations	49,921	61,051
Liabilities from price risk management activities	66,010	19,476
Accrued interest payable	9,509	10,249
Current portion of operating lease liabilities	1,793	1,594
Other current liabilities	24,155	20,180
Total current liabilities	447,534	370,452
Long-term liabilities:		
Long-term debt, net of discount and deferred financing costs	985,512	732,981
Asset retirement obligations	392,348	308,427
Liabilities from price risk management activities	9,625	511
Operating lease liabilities	18,554	17,239
Other long-term liabilities	54,372	81,595
Total liabilities	1,907,945	1,511,205
Commitments and contingencies (Note 12)		
Stockholders' Equity:		
Preferred stock, $0.01 par value; 30,000,000 shares authorized and no shares issued or outstanding as of December 31, 2020 and 2019	—	—
Common stock $0.01 par value; 270,000,000 shares authorized; 81,279,989 and 54,197,004 shares issued and outstanding as of December 31, 2020 and 2019, respectively	813	542
Additional paid-in capital	1,659,800	1,346,142
Accumulated deficit	(734,012)	(268,407)
Total stockholders' equity	926,601	1,078,277
Total liabilities and stockholders' equity	$ 2,834,546	$ 2,589,482

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

TALOS ENERGY INC.
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except share amounts)

	Year Ended December 31,		
	2020	2019	2018
Revenues and Other:			
Oil	$ 506,788	$ 833,118	$ 781,815
Natural gas	53,714	55,278	73,610
NGL	15,434	19,668	35,863
Other	11,550	19,556	—
Total revenues and other	587,486	927,620	891,288
Operating expenses:			
Lease operating expense	246,564	243,427	226,291
Production taxes	1,054	1,349	1,989
Depreciation, depletion and amortization	364,346	345,931	288,719
Write-down of oil and natural gas properties	267,916	12,221	—
Accretion expense	49,741	34,389	35,344
General and administrative expense	79,175	77,209	85,816
Total operating expenses	1,008,796	714,526	638,159
Operating income (expense)	(421,310)	213,094	253,129
Interest expense	(99,415)	(97,847)	(90,114)
Price risk management activities income (expense)	87,685	(95,337)	60,435
Other income	3,018	2,678	1,012
Net income (loss) before income taxes	(430,022)	22,588	224,462
Income tax benefit (expense)	(35,583)	36,141	(2,922)
Net income (loss)	$ (465,605)	$ 58,729	$ 221,540
Net income (loss) per common share:			
Basic	$ (6.88)	$ 1.08	$ 4.81
Diluted	$ (6.88)	$ 1.08	$ 4.81
Weighted average common shares outstanding:			
Basic	67,664	54,185	46,058
Diluted	67,664	54,413	46,061

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

TALOS ENERGY INC.
CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY (DEFICIT)
(In thousands, except share amounts)

	Shares		Par Value		Additional		Total Stockholders
	Common Stock	Preferred Stock	Common Stock	Preferred Stock	Paid- In Capital	Accumulated Deficit	Equity (Deficit)
Balance at December 31, 2017	31,244,085	—	$ 312	$ —	$ 493,952	$ (548,351)	$ (54,087)
Cumulative effect adjustment	—	—	—	—	—	(325)	(325)
Sponsor Debt Exchange	2,874,049	—	29	—	101,971	—	102,000
Stone Combination	20,037,634	—	201	—	731,763	—	731,964
Equity based compensation	—	—	—	—	6,404	—	6,404
Net income	—	—	—	—	—	221,540	221,540
Balance at December 31, 2018	54,155,768	—	542	—	1,334,090	(327,136)	1,007,496
Equity based compensation	53,787	—	—	—	12,385	—	12,385
Shares withheld for taxes on equity transactions	(12,551)	—	—	—	(333)	—	(333)
Net income	—	—	—	—	—	58,729	58,729
Balance at December 31, 2019	54,197,004	—	542	—	1,346,142	(268,407)	1,078,277
Equity based compensation	248,357	—	2	—	16,460	—	16,462
Shares withheld for taxes on equity transactions	(67,832)	—	(1)	—	(826)	—	(827)
Issuances of preferred shares (Note 3)	—	110,000	—	1	156,199	—	156,200
Conversion of preferred shares into common shares (Note 3)	11,000,000	(110,000)	110	(1)	(109)	—	—
Issuance of common stock	8,250,000	—	83	—	70,658	—	70,741
Issuance of common stock for acquisitions (Note 3)	4,602,460	—	46	—	35,347	—	35,393
Issuance of common stock for debt exchange (Note 7)	3,050,000	—	31	—	35,929	—	35,960
Net loss	—	—	—	—	—	(465,605)	(465,605)
Balance at December 31, 2020	81,279,989	—	$ 813	$ —	$1,659,800	$ (734,012)	$ 926,601

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

TALOS ENERGY INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31, 2020	2019	2018
Cash flows from operating activities:			
Net income (loss)	$ (465,605)	$ 58,729	$ 221,540
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Depreciation, depletion, amortization and accretion expense	414,087	380,320	324,063
Write-down of oil and natural gas properties and other well inventory	268,615	12,386	244
Amortization of deferred financing costs and original issue discount	6,804	5,207	4,253
Equity based compensation, net of amounts capitalized	8,669	6,964	2,893
Price risk management activities expense (income)	(87,685)	95,337	(60,435)
Net cash received (paid) on settled derivative instruments	143,905	(8,820)	(111,147)
Gain on Extinguishment of debt	(1,662)	—	—
Settlement of asset retirement obligations	(43,933)	(75,331)	(112,946)
Changes in operating assets and liabilities:			
Accounts receivable	(34,645)	5,788	(786)
Other current assets	35,934	(15,114)	(2,624)
Accounts payable	27,096	7,523	(48,825)
Other current liabilities	4,200	(35,459)	32,044
Other non-current assets and liabilities, net	26,143	(43,797)	15,171
Net cash provided by operating activities	301,923	393,733	263,445
Cash flows from investing activities:			
Exploration, development and other capital expenditures	(362,942)	(463,409)	(240,914)
Cash (paid for) received from acquisitions, net of cash acquired	(315,962)	(37,916)	278,409
Proceeds from sale of other property and equipment	—	5,369	—
Net cash provided by (used in) investing activities	(678,904)	(495,956)	37,495
Cash flows from financing activities:			
Proceeds from issuance of common stock	71,100	—	—
Redemption of Senior Notes and other long-term debt	(5,364)	(10,567)	(25,257)
Proceeds from Bank Credit Facility	350,000	110,000	319,000
Repayment of Bank Credit Facility	(60,000)	(25,000)	(54,000)
Repayment of LLC Bank Credit Facility	—	—	(403,000)
Deferred financing costs	(1,287)	(1,963)	(17,002)
Other deferred payments	(11,921)	(9,921)	—
Payments of finance lease	(17,509)	(14,133)	(12,952)
Employee stock transactions	(827)	(333)	—
Net cash provided by (used in) financing activities	324,192	48,083	(193,211)
Net increase (decrease) in cash, cash equivalents and restricted cash	(52,789)	(54,140)	107,729
Cash, cash equivalents and restricted cash:			
Balance, beginning of period	87,022	141,162	33,433
Balance, end of period	$ 34,233	$ 87,022	$ 141,162
Supplemental Non-Cash Transactions:			
Capital expenditures included in accounts payable and accrued liabilities	$ 74,957	$ 90,956	$ 100,664
Debt exchanged for common stock	$ 35,960	$ —	$ —
Supplemental Cash Flow Information:			
Interest paid, net of amounts capitalized	$ 67,443	$ 62,571	$ 53,476

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

Note 1 — Formation and Basis of Presentation

Formation and Nature of Business

Talos Energy Inc. ("Talos" or the "Company") is a technically driven independent exploration and production company focused on safely and efficiently maximizing value through its operations, currently in the United States ("U.S.") Gulf of Mexico and offshore Mexico. The Company leverages decades of geology, geophysics and offshore operations expertise towards the acquisition, exploration, exploitation and development of assets in key geological trends that are present in many offshore basins around the world.

Talos Energy Inc. was formed in connection with the previously disclosed business combination between Talos Energy LLC and Stone Energy Corporation ("Stone") that occurred on May 10, 2018, pursuant to which Talos Energy LLC and Stone became indirect wholly owned subsidiaries of Talos Energy Inc.

Talos Energy LLC — Talos Energy LLC was formed in 2011 and commenced commercial operations on February 6, 2013. Prior to February 6, 2013, Talos Energy LLC had incurred certain general and administrative expenses associated with the start-up of its operations.

On February 3, 2012, Talos Energy LLC completed a transaction with funds and other alternative investment vehicles managed by Apollo Management VII, L.P. and Apollo Commodities Management, L.P., with respect to Series I ("Apollo Funds"), and entities controlled by or affiliated with Riverstone Energy Partners V, L.P. ("Riverstone Funds", and together with the Apollo Funds, the "Sponsors") and members of management pursuant to which the Company received a private equity capital commitment.

Stone Combination — On May 10, 2018 (the "Stone Closing Date"), the Company (f/k/a Sailfish Energy Holdings Corporation) consummated the transactions contemplated by that certain Transaction Agreement, dated as of November 21, 2017 (the "Transaction Agreement"), by and among Stone, the Company, Sailfish Merger Sub Corporation ("Merger Sub"), Talos Energy LLC and Talos Production LLC (which was converted into a Delaware Corporation and named Talos Production Inc. in 2019), pursuant to which, among other items, each of Stone, Talos Production LLC and Talos Energy LLC became wholly-owned subsidiaries of the Company (the "Stone Combination"). Prior to the Stone Closing Date, the Company did not conduct any material activities other than those incident to its formation and the matters contemplated by the Transaction Agreement.

On the Stone Closing Date, the following transactions, among others, occurred: (i) Stone underwent a reorganization pursuant to which Merger Sub merged with and into Stone, with Stone continuing as the surviving corporation and a direct wholly-owned subsidiary of the Company (the "Merger") and each share of Stone's common stock outstanding immediately prior to the Merger (other than treasury shares held by Stone, which were cancelled for no consideration) was converted into the right to receive one share of the Company's common stock, par value $0.01 (the "Common Stock") and (ii) the Sponsors contributed all of the equity interests in Talos Production LLC (which at that time owned 100% of the equity interests in Talos Energy LLC) to the Company in exchange for an aggregate of 31,244,085 shares of Common Stock (the "Sponsor Equity Exchange").

Concurrently with the consummation of the Transaction Agreement, the Company consummated the transactions contemplated by that certain Exchange Agreement, dated as of November 21, 2017 (the "Exchange Agreement"), among the Company, Stone, the Talos Issuers (defined below), the various lenders and noteholders of the Talos Issuers listed therein, certain funds controlled by Franklin Advisers, Inc. ("Franklin") (such controlled noteholders, the "Franklin Noteholders"), and certain clients of MacKay Shields LLC ("MacKay Shields") (such noteholders, the "MacKay Noteholders"), pursuant to which (i) the Apollo Funds and Riverstone Funds contributed $102.0 million in aggregate principal amount of 9.75% Senior Notes due 2022 ("9.75% Senior Notes") issued by Talos Production LLC and Talos Production Finance, Inc. (together, the "Talos Issuers") to the Company in exchange for an aggregate of 2,874,049 shares of Common Stock (the "Sponsor Debt Exchange"); (ii) the holders of second lien bridge loans ("11.00% Bridge Loans") issued by the Talos Issuers exchanged such 11.00% Bridge Loans for $172.0 million aggregate principal amount of 11.00% Second-Priority Senior Secured Notes due 2022 of the Talos Issuers ("11.00% Notes") and (iii) Franklin Noteholders and MacKay Noteholders exchanged their 7.50% Senior Notes due 2022 issued by Stone ("7.50% Notes") for $137.4 million aggregate principal amount of 11.00% Notes.

Substantially concurrent therewith, the Company consummated an exchange offer and consent solicitation, pursuant to which the holders of the 7.50% Notes, excluding the 7.50% Notes held by the Franklin Noteholders and the MacKay Noteholders, exchanged their 7.50% Notes for 11.00% Notes and a cash payment, and a solicitation of consents to proposed amendments to the 7.50% Notes. Approximately $81.5 million in aggregate principal amount of the 7.50% Notes were validly tendered, and approximately $6.1 million in aggregate principal amount of 7.50% Notes remained outstanding as of the Stone Closing Date.

As a result of the closing of the transactions contemplated by the Transaction Agreement and the Exchange Agreement (the "Transactions") the former stakeholders of Talos Energy LLC held approximately 63% of the Company's outstanding Common Stock and the former stockholders of Stone held approximately 37% of the Company's outstanding Common Stock as of the Stone Closing Date.

Basis of Presentation and Consolidation

The Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") and include each subsidiary from the date of inception. All intercompany transactions have been eliminated. All adjustments are of a normal, recurring nature and are necessary to fairly present the financial position, results of operations and cash flows for the periods are reflected herein. The Company has evaluated subsequent events through the date the Consolidated Financial Statements were issued.

Talos Energy LLC was considered the accounting acquirer in the Stone Combination under GAAP. Accordingly, the historical financial and operating data of Talos Energy Inc., which covers periods prior to the Stone Closing Date, reflects the assets, liabilities and results of operations of Talos Energy LLC and does not reflect the assets, liabilities and results of operations of Stone. For the periods prior to May 10, 2018, the Company retrospectively adjusted its Consolidated Statement of Changes in Stockholders' Equity and the weighted average shares used in determining earnings per share to reflect the number of shares Talos Energy LLC received in the Stone Combination. Beginning on May 10, 2018, common stock is presented to reflect the legal capital of Talos Energy Inc.

The preparation of 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 as of the date of the financial statements, the reported amounts of revenues and expenses during the reporting periods and the reported amounts of proved oil and natural gas reserves. Actual results could differ from those estimates.

For presentation purposes, as of December 31, 2020, operating expenses previously presented as "Direct lease operating expense," "Insurance" and "Workover and maintenance expense" have been combined and presented as "Lease operating expense" on the Company's Consolidated Statements of Operations. Such reclassification had no effect on our results of operations, financial position or cash flows.

The Company has one reportable segment, which is the exploration and production of oil, natural gas and NGLs. Substantially all the Company's long-lived assets, proved reserves and production sales are related to the Company's operations in the United States.

Recently Adopted Accounting Standards

Credit Risk Losses — In June 2016, the Financial Accounting Standards Board issued ASU 2016-13, Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments, which changes accounting requirements for the recognition of credit losses from an incurred or probable impairment methodology to a current expected credit losses ("CECL") methodology. The CECL model is applicable to the measurement of credit losses on financial assets measured at amortized cost, including, but not limited to trade receivables. The guidance was adopted on January 1, 2020 using a modified retrospective approach. The adoption of this guidance did not have a material effect on the Company's Consolidated Financial Statements or related disclosures.

Accounts receivable resulting from the sale of crude oil, natural gas and NGL production and joint interest billings to our partners for their share of expenditures on joint venture projects for which we are the operator are the primary financial assets within the scope of the standard. Although these receivables are from a diverse group of companies, including major energy companies, pipeline companies and joint interest owners, they are concentrated in the oil and gas industry. This concentration has the potential to impact our overall exposure to credit risk in that these companies may be similarly affected by changes in economic and financial conditions, commodity prices or other conditions. A loss-rate methodology is used to estimate the allowance for expected credit losses to be accrued on material receivables to reflect the net amount to be collected. At each reporting period the loss-rate is determined utilizing historical data, current market conditions and reasonable and supported forecast of future economic conditions. Our allowance for uncollectable receivables was $9.2 million at December 31, 2020 and $9.9 million at December 31, 2019.

Guarantor Financial Information — In March 2020, the SEC adopted final rules that simplify the disclosure requirements related to certain registered securities under SEC Regulation S-X, Rules 3-10 and 3-16, permitting registrants to provide certain alternative financial disclosures and non-financial disclosures in lieu of separate Consolidated Financial Statements for subsidiary issuers and guarantors of registered debt securities (which the Company previously presented within the notes to the Financial Statements included in its Annual Report on Form 10-K and Quarterly Reports on Form 10-Q) if certain conditions are met. The disclosure requirements, as amended, are now located in newly created Rules 13-01 and 13-02 of Regulation S-X and are generally effective for filings on or after January 4, 2021, with early adoption permitted. The Company early adopted the new disclosure requirements effective as of July 1, 2020 and are providing the summarized financial information and related disclosures in Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations in this Form 10-K.

Note 2 — Summary of Significant Accounting Policies

Overview of Significant Accounting Policies

Cash and Cash Equivalents — The Company presents cash as "Cash and cash equivalents" on the Company's Consolidated Balance Sheets. The Company considers all cash, money market funds and highly liquid investments with an original maturity of three months or less as cash and cash equivalents. Cash and cash equivalents are carried at cost, which approximates fair value.

Accounts Receivable and Allowance for Uncollectible Accounts — Accounts receivable are stated at the historical carrying amount net of an allowance for uncollectible accounts of $9.2 million at December 31, 2020 and $9.9 million at December 31, 2019. At each reporting period, the recoverability of material receivables is assessed using historical data, current market conditions and reasonable and supported forecasts of future economic conditions to determine their expected collectability. A loss-rate methodology is used to estimate the allowance for expected credit losses to be accrued on material receivables to reflect the net amount to be collected. The Company presented $19.1 million and $18.0 million of refund claims for value added taxes paid in Mexico in "Other assets" on the Consolidated Balance Sheets as of December 31, 2020 and 2019, respectively.

Prepaid Assets — Prepaid assets primarily represent deposits with the Office of Natural Resources Revenue ("ONRR") and transaction escrow related to the ILX and Castex Acquisition as further defined in Note 3 — *Acquisitions.* The deposits with ONRR represent the Company's estimated federal royalties payable within thirty days of the production date. On a monthly basis the Company adjusts the deposit based on actual royalty payments remitted to the ONRR. The transaction escrow was applied to the purchase price that closed in the first quarter of 2020. The escrow for the years ended December 31, 2020 and 2019 were nil and $31.8 million, respectively.

Revenue Recognition — Revenues are recorded based from the sale of oil, natural gas and NGL quantities sold to purchasers. The Company records revenues from the sale of oil, natural gas and NGLs based on quantities of production sold to purchasers under short-term contracts (less than twelve months) at market prices when delivery to the customer has occurred, title has transferred, prices are fixed and determinable and collection is reasonably assured. This occurs when production has been delivered to a pipeline or when a barge lifting has occurred. The Company recognizes transportation costs as a component of lease operating expense when it is the shipper of the product. Each unit of product typically 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.

Gas Imbalances — Revenues are recorded based on the actual sales volumes sold to purchasers. An imbalance receivable or payable is recorded only to the extent the imbalance is in excess of its share of remaining proved developed reserves in an underlying property. Our imbalances are recorded gross on our Consolidated Balance Sheets. At December 31, 2020 and 2019, our imbalance receivable was approximately $1.7 million and $1.7 million, respectively, and imbalance payable was approximately $3.6 million and $3.6 million, respectively.

Production Handling Fees — The Company presented certain reimbursements for costs from certain third parties as a reduction of "Lease operating expense" on the Consolidated Statements of Operations.

ONRR Federal Royalty Refund — Included in "Other" within "Revenues and Other" on the Consolidated Statements of Operations is income from the Company's multi-year federal royalty refund claim from the ONRR. The Company records income when a refund is filed and its collection is reasonably assured. The refunds for the years ended December 31, 2020, 2019 and 2018 were $8.9 million, $19.3 million and nil, respectively.

Accounting for Oil and Natural Gas Activities — The Company follows the full cost method of accounting for oil and natural gas exploration and development activities. Under the full cost method, substantially all costs incurred in connection with the acquisition, development and exploration of oil and natural gas reserves are capitalized. These capitalized amounts include the internal costs directly related to acquisition, development and exploration activities, asset retirement costs and capitalized interest. Under the full cost method, dry hole costs and geological and geophysical costs are capitalized into the full cost pool, which is subject to amortization and assessed for impairment on a quarterly basis through a ceiling test calculation as discussed below.

Capitalized costs associated with proved reserves are amortized on a country by country basis over the life of the total proved reserves using the unit of production method, computed quarterly. Conversely, capitalized costs associated with unproved properties and related geological and geophysical costs, exploration wells currently drilling and capitalized interest are initially excluded from the amortizable base. The Company transfers unproved property costs into the amortizable base when properties are determined to have proved reserves or when the Company has completed an unproved properties evaluation resulting in an impairment. The Company evaluates each of these unproved properties individually for impairment at least quarterly. Additionally, the amortizable base includes future development costs, dismantlement, restoration and abandonment costs, net of estimated salvage values, and geological and geophysical costs incurred that cannot be associated with specific unproved properties or prospects in which the Company owns a direct interest. The Company capitalizes overhead costs that are directly related to exploration, acquisition and development activities.

The Company's capitalized costs are limited to a ceiling based on the present value of future net revenues from proved reserves, computed using a discount factor of 10 percent, plus the lower of cost or estimated fair value of unproved oil and natural gas properties not being amortized less the related tax effects. Any costs in excess of the ceiling are recognized as a non-cash "Write-down of oil and natural gas properties" on the Consolidated Statements of Operations and an increase to "Accumulated depreciation, depletion and amortization" on the Company's Consolidated Balance Sheets. The expense may not be reversed in future periods, even though higher oil, natural gas and NGL prices may subsequently increase the ceiling. The Company performs this ceiling test calculation each quarter. In accordance with the SEC rules and regulations, the Company utilizes SEC Pricing when performing the ceiling test. The Company also holds prices and costs constant over the life of the reserves, even though actual prices and costs of oil and natural gas are often volatile and may change from period to period.

Under the full cost method of accounting for oil and natural gas operations, assets whose costs are currently being depreciated, depleted or amortized are assets in use in the earnings activities of the enterprise and do not qualify for capitalization of interest cost. Investments in unproved properties for which exploration and development activities are in progress and other major development projects that are not being currently depreciated, depleted or amortized are assets qualifying for capitalization of interest costs.

When the Company sells or conveys interests in oil and natural gas properties, the Company reduces its oil and natural gas reserves for the amount attributable to the sold or conveyed interest. The Company treats sales proceeds on non-significant sales as reductions to the cost of the Company's oil and natural gas properties. The Company does not recognize a gain or loss on sales of oil and natural gas properties, unless those sales would significantly alter the relationship between capitalized costs and proved reserves.

Other Property and Equipment — Other property and equipment is recorded at cost and consists primarily of leasehold improvements, office furniture and fixtures, computer hardware and software. Acquisitions, renewals and betterments are capitalized; maintenance and repairs are expensed as incurred. Depreciation is provided using the straight-line method over estimated useful lives of three to ten years.

Other Well Equipment Inventory — Other well equipment inventory primarily represents the cost of equipment to be used in the Company's oil and natural gas drilling and development activities such as drilling pipe, tubulars and certain wellhead equipment. When this inventory is supplied to wells, the cost of this inventory is capitalized in oil and gas properties, and if such property is jointly owned, the proportionate costs will be reimbursed by third party participants. The Company's inventory is stated at the lower of cost or net realizable value. The Company recorded $0.7 million, $0.2 million, and $0.2 million of impairment to adjust inventory to net realizable value, which was expensed and reflected in lease operating expense, during the years ended December 31, 2020, 2019 and 2018, respectively.

Fair Value Measure of Financial Instruments — Financial instruments generally consist of cash and cash equivalents, restricted cash, accounts receivable, commodity derivatives, accounts payable and debt. The carrying amount of cash and cash equivalents, restricted cash, accounts receivable and accounts payable approximates fair value due to the highly liquid nature of these instruments.

Current fair value accounting standards define fair value, establish a consistent framework for measuring fair value and stipulate the related disclosure requirements for each major asset and liability category measured at fair value on either a recurring or nonrecurring basis. These standards also clarify fair value is an exit price, presenting the amount that would be received to sell an asset or paid to transfer a liability, in an orderly transaction between market participants. The Company follows a three-level hierarchy, prioritizing and defining the types of inputs used to measure fair value depending on the degree to which they are observable as follows:

Level 1 – Inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.

Level 2 – Inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial statement.

Level 3 – Inputs to the valuation methodology are unobservable (little or no market data), which require the reporting entity to develop its own assumptions, and are significant to the fair value measurement.

Assets and liabilities measured at fair value are based on one or more of three valuation techniques. The valuation techniques are as follows:

Market Approach – Prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities.

Cost Approach – Amount that would be required to replace the service capacity of an asset (replacement cost).

Income Approach – Techniques to convert expected future cash flows to a single present value amount based on market expectations (including present value techniques, option-pricing and excess earnings models).

Authoritative guidance on financial instruments requires certain fair value disclosures to be presented. The estimated fair value amounts have been determined using available market information and valuation methodologies. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

Asset Retirement Obligations — The Company has obligations associated with the retirement of its oil and natural gas wells and related infrastructure. The Company has obligations to plug wells when production on those wells is exhausted, when the Company no longer plans to use them or when the Company abandons them. The Company accrues a liability with respect to these obligations based on its estimate of the timing and amount to replace, remove or retire the associated assets.

In estimating the liability associated with its asset retirement obligations, the Company utilizes several assumptions, including a credit-adjusted risk-free interest rate, estimated costs of decommissioning services, estimated timing of when the work will be performed and a projected inflation rate. Changes in estimate represent changes to the expected amount and timing of payments to settle its asset retirement obligations. Typically, these changes result from obtaining new information about the timing of its obligations to plug and abandon oil and natural gas wells and the costs to do so. After initial recording, the liability is increased for the passage of time, with the increase being reflected as “Accretion expense” in the Company’s Consolidated Statements of Operations. If the Company incurs an amount different from the amount accrued for decommissioning obligations, the Company recognizes the difference as an adjustment to proved properties.

Price Risk Management Activities — The Company uses commodity price derivatives to manage fluctuating oil and natural gas market risks. The Company periodically enters into commodity derivative contracts, which may require payments to (or receipts from) counterparties based on the differential between a fixed price and a variable price for a fixed quantity of oil or natural gas without the exchange of underlying volumes.

Commodity derivatives are recorded on the Consolidated Balance Sheets at fair value with settlements of such contracts and changes in the unrealized fair value recorded in earnings each period. Realized gains and losses on the settlement of commodity derivatives and changes in their unrealized gains and losses are reported in “Price risk management activities income (expense)” in the Consolidated Statements of Operations. The Company classifies cash flows related to derivative contracts based on the nature and purpose of the derivative. As the derivative cash flows are considered an integral part of the Company’s oil and natural gas operations, they are classified as cash flows from operating activities. The Company does not enter into derivative agreements for trading or other speculative purposes.

The commodity derivative’s fair value reflects the Company’s best estimate with priority based upon exchange or over-the-counter quotations. Quoted valuations may not be available due to location differences or terms that extend beyond the period for which quotations are available. Where quotes are not available, the Company then utilizes other valuation techniques or models to estimate market values. These modeling techniques require the Company to make estimations of future prices, price correlation, market volatility and liquidity. The Company’s actual results may differ from its estimates, and these differences can be favorable or unfavorable.

Leases — At inception, contracts are reviewed to determine whether the agreement contains a lease. To the extent an arrangement is determined to include a lease, it is classified as either an operating or a finance lease, which dictates the pattern of expense recognition in the income statement. Operating leases are reflected as “Operating lease assets”, “Current portion of operating lease liabilities” and “Operating lease liabilities” on the Consolidated Balance Sheets. Finance leases are included in “Property and equipment”, “Other current liabilities”, and “Other long-term liabilities” on the Consolidated Balance Sheets.

A right-of-use (“ROU”) asset representing our right to use an underlying asset for the lease term and a lease liability representing our obligation to make lease payments arising from the lease are recognized on the Consolidated Balance Sheets for all leases, regardless of classification. The ROU asset is initially measured as the present value of the lease liability adjusted for any payments made prior to commencement, including any initial direct costs incurred and incentives received. Lease liabilities are initially measured at the present value of future minimum lease payments, excluding variable lease payments, over the lease term. As most of our leases do not provide an implicit rate, we generally use our incremental borrowing rate based on the estimated rate of interest for collateralized borrowing over a similar term of the lease payments at commencement date.

The Company has elected to account for lease and non-lease components in its contracts as a single lease component for all asset classes. Our lease terms may include options to extend or terminate the lease when it is reasonably certain that we will exercise that option. The Company has elected to not apply the recognition requirements of Topic 842 to leases with durations of twelve months or less (i.e. short-term).

Income Taxes — Prior to the Stone Combination, Talos Energy LLC was a partnership for U.S. federal income tax purposes and was not subject to U.S. federal income tax or state income tax (in most states) at the entity level. As such, Talos Energy LLC did not recognize U.S. federal income tax expense or state income tax expense in most states. In connection with the Stone Combination, Talos Energy LLC was contributed to the Company, which is subject to U.S. federal and state income taxes. The Company records current income taxes based on estimates of current taxable income and provides for deferred income taxes to reflect estimated future income tax payments and receipts. Changes in tax laws are recorded in the period they are enacted. Deferred taxes represent the tax impacts of differences between the financial statement and tax bases of assets and liabilities and carryovers at each year end. The Company classifies all deferred tax assets and liabilities, along with any related valuation allowance, as long-term on the Consolidated Balance Sheets.

The realization of deferred tax assets depends on recognition of sufficient future taxable income during periods in which those temporary differences are deductible. The Company reduces deferred tax assets by a valuation allowance when, based on estimates, it is more likely than not that a portion of those assets will not be realized in a future period. The deferred tax asset estimates are subject to revision, either up or down, in future periods based on new facts or circumstances. In evaluating the Company's valuation allowances, the Company considers cumulative book losses, the reversal of existing temporary differences, the existence of taxable income in carryback years, tax planning strategies and future taxable income for each of its taxable jurisdictions, the latter two of which involve the exercise of significant judgment. Changes to the Company's valuation allowances could materially impact its results of operations.

The Company's policy is to classify interest and penalties associated with underpayment of income taxes as "Interest expense" and "General and administrative expense" on the Consolidated Statements of Operations, respectively.

Income (Loss) Per Share — Basic net income per common share ("EPS") is computed by dividing net income (loss) by the weighted average number of shares of common stock outstanding during the period. Except when the effect would be antidilutive, diluted EPS includes the impact of restricted stock units ("RSUs"), performance share units ("PSUs") and outstanding warrants. See Note 10 — *Income (Loss) Per Share* for additional information.

Share-Based Compensation — Certain of the Company's employees participate in its equity based compensation. The Company measures all employee equity based compensation awards at fair value as calculated using an option pricing method for valuing such securities on the date awards are granted to its employees and recognize compensation cost on a straight-line basis in the Company's financial statements over the vesting period of each grant according to ASC 718, *Compensation—Stock Compensation.*

During 2020, the Company issued RSUs and PSUs to certain employees and non-employee directors. The fair value of the stock-based awards is determined at the date of grant and is not remeasured for awards classified as equity, but is remeasured at each reporting period for awards classified as a liability. The Company records share-based compensation, net of actual forfeitures, for the RSUs and PSUs in "General and administrative expense" on the Consolidated Statements of Operations, net of amounts capitalized to oil and gas properties. See Note 8 — *Employee Benefits Plans and Share-Based Compensation* for additional information.

RSUs — Share-based compensation is based on the market price of the Company's Common Stock on the grant date and recognized over the vesting period using the straight-line method as the requisite service period is fulfilled.

PSUs — Share-based compensation is based on the grant date fair value determined using a Monte Carlo valuation model and recognized over the vesting period using the straight-line method. Estimates used in the Monte Carlo valuation model are considered highly-complex and subjective. The number of shares of Common Stock issuable upon vesting ranges from zero to 200% of the number of PSUs granted based on the Company's total shareholder return ("TSR") relative to the TSR achieved by a specified industry peer group. Share-based compensation related to PSUs is recognized as the requisite service period is fulfilled, even if the market condition is not achieved.

Concentration of Credit Risk

Consisting principally of cash and cash equivalents, accounts receivable and commodity derivatives, the Company is subject to concentrated financial instruments credit risk.

Cash and cash equivalents and balances are maintained in financial institutions, which at times, exceed federally insured limits. The Company monitors the financial condition of these institutions and has not experienced losses on these accounts.

Commodity derivatives are entered into with registered swap dealers, all of which participate in the Company's senior reserve-based revolving credit facility (the "Bank Credit Facility"). The Company monitors the financial condition of these institutions and has not experienced losses due to counterparty default on these instruments.

The Company markets substantially all of its oil and natural gas production, and substantially all of its revenues are attributable to the U.S. The majority of the Company's oil, natural gas and NGL production is sold to customers under short-term (less than 12 months) contracts at market-based prices. The Company's customers consist primarily of major oil and natural gas companies, well-established oil and pipeline companies and independent oil and gas producers and suppliers. The Company performs ongoing credit evaluations of its customers and provide allowances for probable credit losses when necessary. The percent of consolidated revenue of major customers, those whose total represented 10% or more of the Company's oil, natural gas and NGL revenues, was as follows:

	Year Ended December 31,		
	2020	2019	2018
Shell Trading (US) Company	47%	58%	65%
Phillips 66	22%	28%	18%
Chevron Products Company	12%	**	**

** Less than 10%

The loss of a major customer could have material adverse effect on the Company in the short term. However, the Company believes it would be able to obtain other customers to market its oil, natural gas and NGL production.

Note 3 — Acquisitions

Asset Acquisitions

Acquisitions qualifying as an asset acquisition requires, among other items, that the cost of the assets acquired and liabilities assumed to be recognized on the Consolidated Balance Sheets by allocating the asset cost on a relative fair value basis. The fair value measurements of the oil and natural gas properties acquired and asset retirement obligations assumed were derived utilizing an income approach and based, in part, on significant inputs not observable in the market. These inputs represent Level 3 measurements in the fair value hierarchy and include, but are not limited to, estimates of reserves, future operating and development costs, future commodity prices, estimated future cash flows and appropriate discount rates. These inputs required significant judgments and estimates by the Company's management at the time of the valuation. Transaction costs incurred on an asset acquisition are capitalized as a component of the assets acquired and any contingent consideration is recognized as the contingency is resolved.

Acquisition of LLOG Properties — On November 16, 2020, the Company completed the acquisition of select oil and natural gas assets from LLOG Exploration & Production Company, L.L.C. with an effective date of August 1, 2020 (the "LLOG Acquisition"). The oil and natural gas assets consist of interests in the Mississippi Canyon core area. The LLOG Acquisition was consummated pursuant to a Purchase and Sale Agreement executed on November 16, 2020 for $13.2 million in cash, inclusive of customary closing adjustments and $0.2 million of transaction related expenses.

The following table presents the allocation of the purchase price to the assets acquired and liabilities assumed, based on their relative fair values, on November 16, 2020 (in thousands):

Property and equipment	$ 17,421
Asset retirement obligations	(4,234)
Allocated purchase price	$ 13,187

Acquisition of Castex Energy 2005 — On August 5, 2020, the Company completed the acquisition of select oil and natural gas assets from affiliates of Castex Energy 2005 Holdco, LLC with an effective date of April 1, 2020 (the "Castex Energy 2005 Acquisition"). The oil and natural gas assets consist of interests in 16 properties in the U.S. Gulf of Mexico Shelf and Gulf Coast core area. The Castex Energy 2005 Acquisition was consummated pursuant to a Purchase and Sale Agreement dated June 19, 2020 for consideration consisting of (i) $6.5 million in cash, (ii) 4.6 million shares of the Company's common stock and (iii) $1.4 million in transaction related expenses, inclusive of customary closing adjustments.

The following table summarizes the purchase price, inclusive of customary closing adjustments (in thousands except share and per share data):

Talos common stock		4,602,460
Talos common stock price per share[1]	$	7.69
Talos common stock value	$	35,393
Cash consideration	$	6,500
Transaction cost	$	1,413
Total purchase price	$	43,306

(1) Represents the closing price of the Company's common stock on August 5, 2020, the date of the closing of the Castex Energy 2005 Acquisition.

The following table presents the allocation of the purchase price to the assets acquired and liabilities assumed, based on their relative fair values, on August 5, 2020 (in thousands):

Property and equipment	$	46,626
Asset retirement obligations		(3,320)
Allocated purchase price	$	43,306

Acquisition of Gunflint Field — On January 11, 2019, the Company completed the acquisition of an approximate 9.6% non-operated working interest in the Gunflint Field located in the Mississippi Canyon area (the "Gunflint Acquisition") from Samson Offshore Mapleleaf, LLC for $29.6 million ($27.9 million after customary purchase price adjustments).

The following table presents the allocation of the purchase price to the assets acquired and liabilities assumed, based on their relative fair values, on January 11, 2019 (in thousands):

Property and equipment	$	28,912
Asset retirement obligations		(996)
Allocated purchase price	$	27,916

Acquisition of Whistler Energy II, LLC — On August 31, 2018, the Company completed the acquisition of all the issued and outstanding membership interests of Whistler Energy II, LLC ("Whistler") from Whistler Energy II Holdco, LLC, an affiliate of the Apollo Funds (the "Whistler Acquisition"), for $52.6 million ($14.8 million, net of $37.8 million of cash acquired). The $37.8 million of cash acquired consists of $30.8 million of cash collateral posted by Whistler and released by third party surety companies at closing and $7.0 million of cash on hand for working capital purposes. Through the acquisition, the Company acquired and assumed all of Whistler's oil and natural gas assets and the associated asset retirement obligations for interests located in Green Canyon Block 18, Green Canyon Block 60 and Ewing Bank Blocks 944 and 988, including a fixed production platform on Green Canyon Block 18.

The following table presents the allocation of the purchase price to the assets acquired and liabilities assumed, based on their relative fair values, on August 31, 2018 (in thousands):

Current assets[(1)]	$	45,337
Property and equipment		35,344
Other long-term assets		66
Current liabilities		(4,261)
Asset retirement obligations		(23,862)
Allocated purchase price	$	52,624

(1) Includes $37.8 million of cash acquired and trade receivables of $3.2 million, which the Company expects all to be realizable.

Business Combination

Acquisitions qualifying as business combinations are accounted for under the acquisition method of accounting, which requires, among other items, that assets acquired and liabilities assumed be recognized on the Consolidated Balance Sheets at their fair values as of the acquisition date. The fair value measurements of the oil and natural gas properties acquired and asset retirement obligations assumed were derived utilizing an income approach and based, in part, on significant inputs not observable in the market. These inputs represent Level 3 measurements in the fair value hierarchy and include, but are not limited to, estimates of reserves, future operating and development costs, future commodity prices, estimated future cash flows and appropriate discount rates. These inputs required significant judgments and estimates at the time of the valuation.

***ILX and Castex Acquisition* —** On February 28, 2020, the Company acquired the outstanding limited liability interests in certain wholly owned subsidiaries of ILX Holdings, LLC, ILX Holdings II, LLC, ILX Holdings III LLC and Castex Energy 2014, LLC, each a related party and an affiliate of the Riverstone Funds (the "Riverstone Sellers"), and Castex Energy 2016, LP (together with the Riverstone Sellers, the "Sellers") with an effective date of July 1, 2019 (collectively, the "ILX and Castex Acquisition"). The ILX and Castex Acquisition was consummated pursuant to separate Purchase and Sale Agreements, dated December 10, 2019 (as amended from time to time, the "Purchase Agreements") for aggregate consideration consisting of (i) $385.0 million in cash subject to customary closing adjustments and (ii) an aggregate 110,000 shares (the "Preferred Shares") of a series of the Company's preferred stock designated as "Series A Convertible Preferred Stock" which subsequently converted to 11.0 million shares of the Company's common stock on March 30, 2020 (such common stock, the "Conversion Stock"). The cash payment and escrow deposit were funded with borrowings under the Bank Credit Facility.

The following table summarizes the purchase price (in thousands except share and per share data):

Talos Conversion Stock		11,000,000
Talos common stock price per share[(1)]	$	14.20
Conversion Stock value	$	156,200
Cash consideration	$	385,000
Customary closing and post-closing adjustments		(81,878)
Net cash consideration	$	303,122
Total purchase price	$	459,322

(1) Represents the closing price of the Company's common stock on February 28, 2020, the date of the closing of the ILX and Castex Acquisition. The purchase price was based on the value of the Conversion Stock as the value approximates the value of the Preferred Shares as a result of the automatic conversion and dividend rights described in that certain Certificate of Designation, Preferences, Rights and Limitations.

The following table presents the final allocation of the purchase price to the assets acquired and liabilities assumed, based on their fair values on February 28, 2020 (in thousands):

Current assets[1]	$	11,060
Property and equipment		496,835
Other long-term assets		148
Current liabilities		(16,520)
Other long-term liabilities		(32,201)
Allocated purchase price	$	459,322

(1) Includes trade and other receivables of $8.2 million, which the Company expects all to be realizable.

The Company incurred approximately $12.1 million of transaction related costs, of which $8.7 million and $3.4 million were recognized in the years ended December 31, 2020 and 2019, respectively. These costs have been reflected in "General and administrative expense" on the Consolidated Statements of Operations.

The following table presents revenue and net income attributable to the assets acquired in the ILX and Castex Acquisition for the year ended December 31, 2020:

	Year Ended December 31, 2020	
Revenue	$	126,857
Net loss	$	(6,011)

Pro Forma Financial Information (Unaudited) — The following supplemental pro forma financial information (in thousands, except per common share amounts), presents the consolidated results of operations for the years ended December 31, 2020 and 2019 as if the ILX and Castex Acquisition had occurred on January 1, 2019. The unaudited pro forma information was derived from historical statements of operations of the Company and the Sellers adjusted to (i) include depletion expense applied to the adjusted basis of the oil and natural gas properties acquired, (ii) include interest expense to reflect borrowings under the Bank Credit Facility, (iii) eliminate the write-down of oil and natural gas properties on the assets acquired to reflect the pro-forma ceiling test calculation and (iv) include weighted average basic and diluted shares of common stock outstanding, which was calculated assuming the 11.0 million shares of Conversion Stock were issued to the Sellers. This information does not purport to be indicative of results of operations that would have occurred had the ILX and Castex Acquisition occurred on January 1, 2019, nor is such information indicative of any expected future results of operations.

	Year Ended December 31,			
	2020		2019	
Revenue	$	634,921	$	1,246,391
Net income (loss)	$	(449,988)	$	148,091
Basic net income (loss) per common share	$	(6.48)	$	2.27
Diluted net income (loss) per common share	$	(6.48)	$	2.26

Combination Between Talos Energy LLC and Stone Energy Corporation — On May 10, 2018, the Company consummated the Transactions contemplated by the Transaction Agreement and Exchange Agreement, pursuant to which, among other things, Talos Energy LLC and Stone became wholly-owned subsidiaries of the Company. The combination was executed as an all-stock transaction whereby the former stakeholders of Talos Energy LLC held approximately 63% of the Company's outstanding Common Stock and the former stockholders of Stone held approximately 37% of the Company's outstanding Common Stock as of the Stone Closing Date.

The purchase price of $732.0 million is based on the closing price of Stone common stock and common warrants immediately prior to closing. The following table summarizes the purchase price (in thousands, except per share data):

Stone Energy common stock - issued and outstanding as of May 9, 2018		20,038
Stone Energy common stock price	$	35.49
Common stock value	$	711,149
Stone Energy common stock warrants - issued and outstanding as of May 9, 2018		3,528
Stone Energy common stock warrants price	$	5.90
Common stock warrants value	$	20,815
Total purchase price	$	731,964

During 2018, the Company incurred approximately $88.6 million of transaction related costs, of which, $32.5 million was expensed and reflected in "General and administrative expense" on the Consolidated Statements of Operations. The remaining $56.1 million was the result of (i) $9.3 million in work fees paid to holders of the 11.00% Notes reflected as a debt discount reducing "Long-term debt" on the Consolidated Balance Sheets and (ii) $46.8 million in fees for seismic use agreements for change in control provisions and reflected in "Proved properties" on the Consolidated Balance Sheets.

The following table presents the final allocation of the purchase price to the assets acquired and liabilities assumed, based on their fair values on May 10, 2018 (in thousands):

Current assets[(1)]	$	372,963
Property and equipment		886,406
Other long-term assets		19,494
Current liabilities		(132,846)
Long-term debt		(235,416)
Other long-term liabilities		(178,637)
Allocated purchase price	$	731,964

(1) Includes $293.0 million of cash acquired. The fair values of current assets acquired includes trade receivables and joint interest receivables of $43.3 million and $3.5 million, respectively, which the Company expects all to be realizable.

The follow table presents revenue and net income attributable to the assets acquired in the Stone Combination for the years ended December 31, 2020, 2019 and 2018:

		Year Ended December 31,		
		2020	2019	2018
Revenue	$	187,211	414,056	332,944
Net income (loss)	$	(1,232)	187,428	148,473

Pro Forma Financial Information (Unaudited) — The following supplemental pro forma information (in thousands, except per common share amounts), presents the consolidated results of operations for the year ended December 31, 2018 as if the Stone Combination had occurred on January 1, 2018. The unaudited pro forma information was derived from historical statements of operations of the Company and Stone and adjusted to include (i) depletion and accretion expense applied to the adjusted basis of the oil and natural gas properties acquired, (ii) interest expense to reflect the debt transactions contemplated by the Exchange Agreement and (iii) general and administrative expense adjusted for transaction related costs incurred. This information does not purport to be indicative of results of operations that would have occurred had the Stone Combination occurred on January 1, 2018, nor is such information indicative of any expected future results of operations.

		Year Ended December 31, 2018
Revenue	$	1,013,184
Net income	$	274,577
Basic net income per common share	$	5.07
Diluted net income per common share	$	5.07

Note 4 — Property, Plant and Equipment

Proved Properties

The Company's interests in oil and natural gas proved properties are located in the United States, primarily in the Gulf of Mexico deep and shallow waters. The Company follows the full cost method of accounting for its oil and natural gas exploration and development activities.

Pursuant to SEC Regulation S-X, Rule 4-10, under the full cost method of accounting, the Company's capitalized oil and natural gas costs are limited to a ceiling based on the present value of future net revenues from proved reserves, computed using a discount factor of 10%, plus the lower of cost or estimated fair value of unproved oil and natural gas properties not being amortized less the related tax effects. The Company performs this ceiling test calculation each quarter utilizing SEC pricing. During 2020, 2019 and 2018, the Company's ceiling test computations resulted in a write-down of its U.S. oil and natural gas properties of $267.9 million, nil and nil, respectively. At December 31, 2020, its ceiling test computation was based on SEC pricing of $39.47 per Bbl of oil, $1.97 per Mcf of natural gas and $9.89 per Bbl of NGLs.

Unproved Properties

Unproved capitalized costs of oil and natural gas properties excluded from amortization relate to unevaluated properties associated with acquisitions, leases awarded in the U.S. Gulf of Mexico federal lease sales, certain geological and geophysical costs, expenditures associated with certain exploratory wells in progress and capitalized interest. Unproved properties also include expenditures associated with exploration and appraisal activities in Block 7 and Block 31 located in the shallow waters off the coast of Mexico's Veracruz and Tabasco states.

The following table sets forth a summary of the Company's oil and natural gas property costs not being amortized at December 31, 2020, by the year in which such costs were incurred (in thousands):

		Year Ended December 31,			
	Total	2020	2019	2018	2017 and Prior
Acquisition United States	$ 80,799	$ 61,315	$ 3,268	$ 16,216	$ —
Exploration United States	52,470	12,714	32,698	5,761	1,297
Exploration Mexico	121,725	14,811	61,809	14,362	30,743
Total unproved properties, not subject to amortization	$ 254,994	$ 88,840	$ 97,775	$ 36,339	$ 32,040

The excluded costs will be included in the amortization base as properties are evaluated and proved reserves are established or impairment is determined.

The Company's evaluation of unproved property located in Block 2 offshore Mexico, specifically future exploratory drilling opportunities, results from exploratory wells drilled during the second quarter of 2019 and the Block 2 production sharing contract's expiration date resulted in the Company recording a non-cash impairment presented as "Write-down of oil and natural gas properties" on the Consolidated Statements of Operations. For the years ended December 31, 2020, 2019 and 2018, the Company recorded an impairment of $0.1 million, $12.2 million and nil, respectively.

Asset Retirement Obligations

The discounted asset retirement obligations included in the Consolidated Balance Sheets in current and non-current liabilities, and the changes in that liability during each of the years ended December 31, 2020 and 2019 were as follows (in thousands):

	Year Ended December 31,	
	2020	2019
Asset retirement obligations at January 1	$ 369,478	$ 382,817
Fair value of asset retirement obligations acquired[(1)]	44,311	5,047
Obligations settled	(43,933)	(75,331)
Fair value of asset retirement obligations divested	(185)	(5,450)
Accretion expense	49,741	34,389
Obligations incurred	4,511	4,111
Changes in estimate	18,346	23,895
Asset retirement obligations at December 31	$ 442,269	$ 369,478
Less: Current portion	(49,921)	(61,051)
Long-term portion	$ 392,348	$ 308,427

(1) Year ended December 31, 2020 includes $35.3 million, $3.3 million and $4.2 million of asset retirement obligations assumed in the ILX and Castex Acquisition, Castex Energy 2005 Acquisition and LLOG Acquisition, respectively.

Note 5 — Leases

The Company enters into service contracts and other contractual arrangements for the use of office space, drilling, completion and abandonment equipment (e.g., drilling rigs), production related equipment (e.g., compressors) and other equipment from third-party lessors to support its operations. The Company's leasing activities as a lessor are negligible. At inception, contracts are reviewed to determine whether the agreement contains a lease. To the extent an arrangement is determined to include a lease, it is classified as either an operating or a finance lease, which dictates the pattern of expense recognition in the income statement.

The amounts disclosed herein primarily represent costs associated with properties operated by the Company that are presented on a gross basis and do not reflect the Company's net proportionate share of such amounts. A portion of these costs have been or may be billed to other working interest owners. The Company's share of these costs is included in property and equipment, lease operating expense or general and administrative expense depending on how the leased asset is utilized. The components of lease costs were as follows (in thousands):

	Year Ended December 31,	
	2020	2019
Finance lease cost - interest on lease liabilities[(1)]	$ 15,748	$ 19,115
Operating lease cost, excluding short-term leases[(2)]	3,361	3,261
Short-term lease cost[(3)]	53,573	85,865
Variable lease cost[(4)]	543	11
Total lease cost	$ 73,225	$ 108,252

(1) The Helix Producer I (the "HP-I") is utilized in the Company's oil and natural gas development activities and the right-of-use asset was capitalized and included in proved property and depleted as part of the full cost pool. Once items are included in the full cost pool, they are indistinguishable from other proved properties. The capitalized costs within the full cost pool are amortized over the life of the total proved reserved using the unit-of-production method, computed quarterly.

(2) Operating lease cost reflect a single lease cost, calculated so that the cost of the lease is allocated over the lease term on a straight-line basis.

(3) Short-term lease costs are reported at gross amounts and primarily represent costs incurred for drilling rigs, most of which are short-term contracts not recognized as a right-of-use asset and lease liability on the Consolidated Balance Sheets.

(4) Variable lease costs primarily represent differences between minimum payment obligations and actual operating charges incurred by the Company related to its long-term leases.

The present value of the fixed lease payments recorded as the Company's right-of-use asset and liability, adjusted for initial direct costs and incentives are as follows (in thousands):

	Year Ended December 31, 2020		Year Ended December 31, 2019	
Operating leases:				
Operating lease assets	$	6,855	$	7,779
Current portion of operating lease liabilities	$	1,793	$	1,594
Operating lease liabilities		18,554		17,239
Total operating lease liabilities	$	20,347	$	18,833
Finance leases:				
Proved property [1]	$	124,299	$	124,299
Other current liabilities	$	21,804	$	17,509
Other long-term liabilities		40,222		62,026
Total finance lease liabilities	$	62,026	$	79,535

(1) The HP-I is utilized in the Company's oil and natural gas development activities and the right-of-use asset was capitalized and included in proved property and depleted as part of the full cost pool. Once items are included in the full cost pool, they are indistinguishable from other proved properties. The capitalized costs within the full cost pool are amortized over the life of the total proved reserves using the unit-of-production method, computed quarterly.

The table below presents the lease maturity by year as of December 31, 2020 (in thousands). Such commitments are reflected at undiscounted values and are reconciled to the discounted present value recognized on the Consolidated Balance Sheets.

	Operating Leases		Finance Leases	
2021	$	4,079	$	33,257
2022		4,302		33,257
2023		4,239		13,857
2024		3,315		—
2025		3,293		—
Thereafter		12,497		—
Total lease payments	$	31,725	$	80,371
Imputed interest		(11,378)		(18,345)
Total	$	20,347	$	62,026

The table below presents the weighted average remaining lease term and discount rate related to leases for the years ended December 31, 2020 and 2019:

	Year Ended December 31, 2020	Year Ended December 31, 2019
Weighted average remaining lease term:		
Operating leases	7.8 years	8.4 years
Finance leases	2.4 years	3.4 years
Weighted average discount rate:		
Operating leases	12.0%	10.2%
Finance leases	21.9%	21.9%

The table below presents the supplemental cash flow information related to leases for the years ended December 31, 2020 and 2019 (in thousands):

	Year Ended December 31,	
	2020	2019
Operating cash outflow from finance leases	$ 15,748	$ 19,115
Financing cash outflow from finance leases	$ 17,509	$ 14,133
Operating cash outflow from operating leases	$ 2,648	$ 1,812
Right-of-use assets obtained in exchange for new operating lease liabilities	$ —	$ 2,225

Note 6 — Financial Instruments

The following table presents the carrying amounts and estimated fair values of the Company's financial instruments (in thousands):

	December 31, 2020		December 31, 2019	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
11.00% Second-Priority Senior Secured Notes – due April 2022[(1)]	$ 343,579	$ 355,935	$ 383,871	$ 401,128
7.50% Senior Notes – due May 2022	$ 6,060	$ 5,238	$ 6,060	$ 5,030
Bank Credit Facility – matures May 2022[(1)]	$ 635,873	$ 640,000	$ 343,050	$ 350,000
Oil and Natural Gas Derivatives	$ (67,814)	$ (67,814)	$ (11,594)	$ (11,594)

(1) The carrying amounts are net of discount and deferred financing costs.

As of December 31, 2020 and 2019, the carrying amounts of cash and cash equivalents, accounts receivable and accounts payable approximate their fair values because of the short-term nature of these instruments.

11.00% Second-Priority Senior Secured Notes – due April 2022

The $347.3 million aggregate principal amount of 11.00% Notes is reported on the Consolidated Balance Sheets at its carrying value, net of original issue discount and deferred financing costs, see Note 7 — *Debt*. The fair value of the 11.00% Notes is estimated (representing a Level 1 fair value measurement) using quoted secondary market trading prices.

7.50% Senior Notes – due May 2022

The $6.1 million aggregate principal amount of 7.50% Notes is reported on the Consolidated Balance Sheets at its carrying value, see Note 7 — *Debt*. The fair value of the 7.50% Notes is estimated (representing a Level 1 fair value measurement) using quoted secondary market trading prices.

Bank Credit Facility – matures May 2022

The Company and Talos Production Inc., our wholly-owned subsidiary that was formerly known as Talos Production LLC, maintains a Bank Credit Facility with a borrowing base of $985.0 million at December 31, 2020 (the "Bank Credit Facility"), which is reported on the Consolidated Balance Sheets at its carrying value net of deferred financing costs (see Note 7 – *Debt*). The fair value of the Bank Credit Facility is estimated based on the outstanding borrowings under the Bank Credit Facility since it is secured by the Company's reserves and the interest rates are variable and reflective of market rates (representing a Level 2 fair value measurement).

Oil and natural gas derivatives

The Company attempts to mitigate a portion of its commodity price risk and stabilize cash flows associated with sales of oil and natural gas production through the use of oil and natural gas swaps and costless collars. Swaps are contracts where the Company either receives or pays depending on whether the oil or natural gas floating market price is above or below the contracted fixed price. Costless collars consist of a purchased put option and a sold call option with no net premiums paid to or received from counterparties. Collar contracts typically require payments by the Company if the NYMEX average closing price is above the ceiling price or payments to the Company if the NYMEX average closing price is below the floor price.

The Company has elected not to designate any of its derivative contracts for hedge accounting. Accordingly, commodity derivatives are recorded on the Consolidated Balance Sheets at fair value with settlements of such contracts, and changes in the unrealized fair value, recorded as "Price risk management activities income (expense)" on the Consolidated Statements of Operations in each period.

The following table presents the impact that derivatives, not qualifying as hedging instruments, had on its Consolidated Statements of Operations (in thousands):

	Year Ended December 31,		
	2020	2019	2018
Net cash received (paid) on settled derivative instruments	$ 143,905	$ (8,820)	$ (111,147)
Unrealized gain (loss)	(56,220)	(86,517)	171,582
Price risk management activities income (expense)	$ 87,685	$ (95,337)	$ 60,435

The following table reflects the contracted volumes and weighted average prices the Company will receive under the terms of its derivative contracts as of December 31, 2020:

Production Period	Instrument Type	Average Daily Volumes	Weighted Average Swap Price	Weighted Average Put Price	Weighted Average Call Price
Crude Oil – WTI:		*(Bbls)*	*(per Bbl)*	*(per Bbl)*	*(per Bbl)*
January 2021 – December 2021	Swaps	22,948	$ 43.20	$ —	$ —
January 2021 – December 2021	Collars	1,000	$ —	$ 30.00	$ 40.00
January 2022 – December 2022	Swaps	10,616	$ 44.45	$ —	$ —
Crude Oil – LLS:		*(Bbls)*	*(per Bbl)*	*(per Bbl)*	*(per Bbl)*
January 2021 – December 2021	Swaps	3,000	$ 38.83	$ —	$ —
Natural Gas – NYMEX Henry Hub:		*(MMBtu)*	*(per MMBtu)*	*(per MMBtu)*	*(per MMBtu)*
January 2021 – December 2021	Swaps	58,907	$ 2.56	$ —	$ —
January 2021 – December 2021	Collars	5,000	$ —	$ 2.50	$ 3.10
January 2022 – December 2022	Swaps	29,649	$ 2.60	$ —	$ —
January 2023 – June 2023	Swaps	5,000	$ 2.61	$ —	$ —

The following tables provide additional information related to financial instruments measured at fair value on a recurring basis (in thousands):

	December 31, 2020			
	Level 1	Level 2	Level 3	Total
Assets:				
Oil and natural gas swaps and costless collars	$ —	$ 7,821	$ —	$ 7,821
Liabilities:				
Oil and natural gas swaps and costless collars	—	(75,635)	—	(75,635)
Total net liability	$ —	$ (67,814)	$ —	$ (67,814)

	December 31, 2019			
	Level 1	Level 2	Level 3	Total
Assets:				
Oil and natural gas swaps and costless collars	$ —	$ 8,393	$ —	$ 8,393
Liabilities:				
Oil and natural gas swaps and costless collars	—	(19,987)	—	(19,987)
Total net liability	$ —	$ (11,594)	$ —	$ (11,594)

Financial Statement Presentation

Derivatives are classified as either current or non-current assets or liabilities based on their anticipated settlement dates. Although the Company has master netting arrangements with its counterparties, the Company presents its derivative financial instruments on a gross basis in its Consolidated Balance Sheets. On derivative contracts recorded as assets in the table below, the Company is exposed to the risk the counterparties may not perform. The following table presents the fair value of derivative financial instruments at December 31, 2020 and 2019 (in thousands):

	December 31, 2020		December 31, 2019	
	Assets	Liabilities	Assets	Liabilities
Oil and natural gas derivatives:				
Current	$ 6,876	$ 66,010	$ 8,393	$ 19,476
Non-current	945	9,625	—	511
Total	$ 7,821	$ 75,635	$ 8,393	$ 19,987

Credit Risk

The Company is subject to the risk of loss on its financial instruments as a result of nonperformance by counterparties pursuant to the terms of their contractual obligations. The Company entered into International Swaps and Derivative Association agreements with counterparties to mitigate this risk. The Company also maintains credit policies with regard to its counterparties to minimize overall credit risk. These policies require (i) the evaluation of potential counterparties' financial condition to determine their credit worthiness; (ii) the regular monitoring of counterparties' credit exposures; (iii) the use of contract language that affords the Company netting or set off opportunities to mitigate exposure risk; and (iv) potentially requiring counterparties to post cash collateral, parent guarantees, or letters of credit to minimize credit risk. The Company's assets and liabilities from commodity price risk management activities at December 31, 2020 represent derivative instruments from nine counterparties; all of which are registered swap dealers that have an "investment grade" (minimum Standard & Poor's rating of BBB- or better) credit rating, and all of which are parties under the Company's Bank Credit Facility. The Company enters into derivatives directly with these counterparties and, subject to the terms of the Company's Bank Credit Facility, is not required to post collateral or other securities for credit risk in relation to the derivative activities.

Note 7 — Debt

A summary of the detail comprising the Company's debt and the related book values for the respective periods presented is as follows (in thousands):

	Year Ended December 31,	
	2020	2019
11.00% Second-Priority Senior Secured Notes – due April 2022	$ 347,254	$ 390,868
7.50% Senior Notes – due May 2022	6,060	6,060
Bank Credit Facility – matures May 2022	640,000	350,000
Total debt, before discount and deferred financing cost	993,314	746,928
Discount and deferred financing cost	(7,802)	(13,947)
Total debt, net of discount and deferred financing costs	$ 985,512	$ 732,981

11.00% Second-Priority Senior Secured Notes – due April 2022

The 11.00% Notes were issued pursuant to an indenture dated May 10, 2018, between Talos Production Inc. (formerly Talos Production LLC) and Talos Production Finance Inc., the subsidiary guarantors party thereto and Wilmington Trust, National Association, as trustee and collateral agent. The 11.00% Notes mature April 3, 2022 and have interest payable semi-annually each April 15 and October 15. Prior to May 10, 2021, the Company may, at its option, redeem all or a portion of the 11.00% Notes at 102.75% of the principal amount plus accrued and unpaid interest. Thereafter, the Company may redeem all or a portion of the 11.00% Notes at redemption prices decreasing annually from May 10 at 102.75% to 100.0% plus accrued and unpaid interest.

The indenture governing the 11.00% Notes applies certain limitations on the Company's ability and the ability of its subsidiaries to, among other things, (i) incur additional indebtedness or issue certain preferred shares; (ii) pay dividends and make certain other restricted payments; (iii) create restrictions on the payment of dividends or other distributions to the Company from its restricted subsidiaries; (iv) create liens on certain assets to secure debt; (v) make certain investments; (vi) engage in sales of assets and subsidiary stock; (vii) transfer all or substantially all of its assets or enter into merger or consolidation transactions; and (viii) engage in transactions with affiliates. The 11.00% Notes contain customary quarterly and annual reporting, financial and administrative covenants. The Company was in compliance with all debt covenants at December 31, 2020.

On June 15, 2020, the Company entered into an exchange agreement pursuant to which the Company agreed to exchange $37.2 million aggregate principal amount of the 11.00% Notes from certain holders in exchange for 3.1 million shares of the Company's common stock plus cash in an amount equal to accrued interest up to the June 18, 2020 settlement date. Additionally, during the year ended December 31, 2020, the Company repurchased $6.4 million of the 11.00% Notes. The exchange agreement and debt repurchases resulted in a gain on extinguishment of debt for the year ended December 31, 2020 of $1.7 million, which is presented as "Other income (expense)" on the Consolidated Statements of Operations.

7.50% Senior Notes – due May 2022

The 7.50% Notes represent the remaining $6.1 million of long-term debt assumed in the Stone Combination that were not exchanged for 11.00% Notes pursuant to the exchange offer and consent solicitation, and thus remain outstanding. As a result of the exchange offer and consent solicitation, substantially all of the restrictive covenants relating to the 7.50% Notes have been removed and collateral securing the 7.50% Notes has been released. The 7.50% Notes mature May 31, 2022 and have interest payable semi-annually each May 31 and November 30. Prior to May 31, 2021, the Company may, at its option, redeem all of the 7.50% Notes at 105.63% of the principal amount plus accrued and unpaid interest. Thereafter, the Company may redeem all or a portion of the 7.50% Notes at redemption prices decreasing annually at May 31 from 105.63% to 100.0% plus accrued and unpaid interest.

Bank Credit Facility – matures May 2022

The Company and Talos Production Inc. maintain a Bank Credit Facility with a syndicate of financial institutions, with a borrowing base of $985.0 million as of December 31, 2020. The Bank Credit Facility matures on May 10, 2022, provided that the Bank Credit Facility mandates a springing maturity that is 120 days prior to the maturity date of the 11.00% Notes (such 120 days prior being December 4, 2021), if greater than $25.0 million of the 11.00% Notes or any permitted refinancing indebtedness in respect thereof is outstanding on such date.

The Bank Credit Facility bears interest based on the borrowing base usage, at the applicable London InterBank Offered Rate, plus applicable margins ranging from 3.00% to 4.00% or an alternate base rate, based on the federal funds effective rate plus applicable margins ranging from 2.00% to 3.00%. In addition, the Company is obligated to pay a commitment fee of 0.50% on the unutilized portion of the commitments. The Bank Credit Facility has certain debt covenants, the most restrictive of which is that the Company must maintain a total debt to EBITDAX Ratio (as defined in the Bank Credit Facility) of no greater than 3.00 to 1.00 calculated each quarter utilizing the most recent twelve months to determine EBITDAX. The Company must also maintain a current ratio no less than 1.00 to 1.00 each quarter. According to the Bank Credit Facility, unutilized commitments are included in current assets in the current ratio calculation. The Bank Credit Facility is secured by substantially all of the oil and natural gas assets of the Company. The Bank Credit Facility is fully and unconditionally guaranteed by the Company and certain of its wholly-owned subsidiaries.

The Bank Credit Facility provides for determination of the borrowing base based on the Company's proved producing reserves and a portion of our PUD reserves. The borrowing base is redetermined by the lenders at least semi-annually during the second quarter and fourth quarter each year. Upon closing of the ILX and Castex Acquisition on February 28, 2020, the maximum borrowing base and commitments were increased from $950.0 million to $1.15 billion. On June 19, 2020, the borrowing base was redetermined by the lenders and decreased from $1.15 billion to $985.0 million. The redetermination on June 19, 2020 also required certain lender approval to access the last $25.0 million of the borrowing base. On December 7, 2020, the borrowing base was reaffirmed at $985.0 million.

As of December 31, 2020, no more than $200.0 million of the Company's borrowing base can be used as letters of credit. The amount the Company is able to borrow with respect to the borrowing base is subject to compliance with the financial covenants and other provisions of the Bank Credit Facility. The Company was in compliance with all debt covenants at December 31, 2020. As of December 31, 2020, the Company had $640.0 million of outstanding borrowings and $13.6 million in letters of credit issued under the Bank Credit Facility.

Subsequent Events

Issuance of 12.00% Second-Priority Senior Notes – due January 2026 — On January 4, 2021, the Company issued $500.0 million in aggregate principal amount of 12.00% Second-Priority Senior Secured Notes due January 2026 (the "12.00% Notes"). The 12.00% Notes were issued pursuant to an indenture dated January 4, 2021 between Talos Energy Inc., Talos Production Inc., the subsidiary guarantors party thereto and Wilmington Trust, National Association, as trustee and collateral agent. The 12.00% Notes have interest payable semi-annually each January 15 and July 15, commencing on July 15, 2021. At any time prior to January 15, 2023, the Company may redeem up to 40% of the principal amount of 12.00% Senior Notes at a redemption rate of 112.00% of the principal amount plus accrued and unpaid interest. Thereafter, the Company may redeem all or a portion of the 12.00% Notes decreasing annually at 106.00% to 100.00%.

On January 14, 2021, the Company issued $150.0 million in aggregate principal amount of the 12.00% Notes pursuant to the first supplemental indenture dated January 14, 2021. The $150.0 million and $500.0 million in 12.00% Notes rank pari passu in right of payment and constitute a single class of securities for all purposes under the indenture. The issuances of 12.00% Notes on January 4, 2021 and January 14, 2021 resulted in $600.5 million in gross proceeds.

Redemption of 11.00% Second-Priority Senior Secured Notes – due April 2022 — On January 13, 2021, the Company redeemed $347.3 million aggregate principal amount of the 11.00% Notes using the proceeds from the issuance of 12.00% Notes.

As result of the issuances of the 12.00% Notes exceeding $550.0 million, the Bank Credit Facility borrowing base was reduced from $985.0 million to $960.0 million under the terms of the Bank Credit Facility. Additionally, the redemption of the 11.00% Notes eliminated the Bank Credit Facility mandated springing maturity that was 120 days prior to the maturity date of the 11.00% Notes, if greater than $25.0 million of the 11.00% Notes are outstanding.

Bank Credit Facility – matures May 2022 — On January 14, 2021, the borrowing base was reduced from $985.0 million to $960.0 million per the terms of the credit facility as a result of the additional indebtedness from the 12.00% Notes. Additionally, during January 2021, the Company repaid $175.0 million of outstanding borrowings under the Bank Credit Facility. Inclusive of the $25.0 million reduction to the borrowing base and $175.0 million repayment, the Company had $465.0 million of outstanding borrowings and $13.6 million in letters of credit issued under the $960.0 million borrowing base.

Note 8 — Employee Benefits Plans and Share-Based Compensation

Stone Change of Control and Severance Plans

As a result of the Stone Combination, the Company assumed the Stone Energy Corporation Executive Severance Plan and Stone Energy Corporation Employee Severance Plan, each a legacy plan of Talos Petroleum LLC (f/k/a Stone Energy Corporation). The plans provided for the payment of severance and change in control benefits to certain individuals who, prior to the Stone Combination, were executive officers or employees of Talos Petroleum LLC, in each case upon an involuntary termination within twelve months of the Stone Closing Date. For the years ended December 31, 2020, 2019 and 2018 the Company incurred nil, $0.2 million and $7.8 million, respectively, of severance expense, reflected in "General and administrative expense" on the Consolidated Statements of Operations. The plans were terminated on July 11, 2019.

Talos Energy Inc. Long Term Incentive Plan

Under the Talos Energy Inc. Long Term Incentive Plan (the "LTIP"), the Company may issue, subject to approval by the Talos board of directors, grants of options (including incentive stock options), stock appreciation rights, restricted stock, restricted stock units, stock awards, dividend equivalents, other stock-based awards, cash awards, substitute awards or any combination of the foregoing to employees, directors and consultants. The LTIP authorizes the Company to grant awards of up to 5,415,576 shares of the Company's common stock.

Restricted Stock Units – Employees — RSUs granted to employees under the LTIP primarily vest ratably over an approximate three year period subject to such employee's continued service through each vesting date. Upon vesting, each RSU represents a contingent right to receive one share of Common Stock. The total unrecognized share-based compensation expense related to these RSUs at December 31, 2020 was approximately $14.3 million, which is expected to be recognized over a weighted average period of 1.8 years.

Restricted Stock Units – Non-employee Directors —RSUs granted to non-employee directors under the LTIP vested approximately one year following the date of grant, subject to such non-employee director's continued service through the vesting date. Upon vesting, these RSUs represent a contingent right to receive one share of Common Stock for each RSU for 60%, and cash for the remaining 40%. The total unrecognized share-based compensation expense related to these RSUs at December 31, 2020 was approximately $0.1 million, which is expected to be recognized over a weighted average period of 0.2 years. Of the unrecognized share-based compensation expense, $0.1 million relates to liability awards and will be subsequently remeasured at each reporting period.

The following table summarizes RSU activity for the years ended December 31, 2020, 2019 and 2018:

	Restricted Stock Units	Weighted Average Grant Date Fair Value
Unvested RSUs at December 31, 2017	—	$ —
Granted	139,411	$ 33.85
Vested	(53)	$ 32.86
Forfeited	(654)	$ 32.86
Unvested RSUs at December 31, 2018	138,704	$ 33.85
Granted	732,771	$ 24.39
Vested	(69,235)	$ 33.72
Forfeited	(68,463)	$ 25.43
Unvested RSUs at December 31, 2019	733,777	$ 25.20
Granted	1,284,797	$ 10.02
Vested	(273,787)	$ 25.09
Forfeited	(91,799)	$ 19.65
Unvested RSUs at December 31, 2020	1,652,988	$ 13.73

Performance Share Units – Employees —PSUs granted to employees under the LTIP represent the contingent right to receive one share of Common Stock. However, the number of shares of Common Stock issuable upon vesting ranges from zero to 200% of the target number of PSUs granted based on the TSR of the Common Stock relative to the TSR achieved by a specific industry peer group over an approximate three-year performance period, the last day of which is also the vesting date. The total unrecognized share-based compensation expense related to these PSUs at December 31, 2020 was approximately $7.4 million, which is expected to be recognized over a weighted average period of 1.5 years.

The following table summarizes PSU activity for the years ended December 31, 2020, 2019 and 2018:

	Performance Share Units	Weighted Average Grant Date Fair Value
Unvested PSUs at December 31, 2017	—	$ —
Granted	232,891	$ 44.47
Vested	—	$ —
Forfeited	(1,349)	$ 42.94
Unvested PSUs at December 31, 2018	231,542	$ 44.47
Granted	218,060	$ 33.96
Vested	—	$ —
Forfeited	(31,771)	$ 40.27
Unvested PSUs at December 31, 2019	417,831	$ 39.31
Granted	441,642	$ 13.05
Vested	—	$ —
Forfeited	(25,301)	$ 37.67
Unvested PSUs at December 31, 2020	834,172	$ 25.46

The grant date fair value of the PSUs, calculated using a Monte Carlo simulation, was $5.8 million, $7.4 million and $10.4 million for the years ended December 31, 2020, 2019 and 2018. The following table summarizes the assumptions used to calculate the grant date fair value of the PSUs granted for the years ended December 31, 2020, 2019 and 2018:

	2020 Grant Date	2019 Grant Date		2018 Grant Date	
	March 5	March 5	May 16	August 29	September 28
Number of simulations	100,000	100,000	100,000	100,000	100,000
Expected term (in years)	2.8	2.8	2.6	2.7	2.6
Expected volatility	48.8%	46.9%	44.8%	50.6%	47.4%
Risk-free interest rate	0.6%	2.5%	2.1%	2.7%	2.9%
Dividend yield	—%	—%	—%	—%	—%

Talos Energy LLC Series B Units

Prior to the Stone Combination, the Limited Liability Company Agreement of Talos Energy LLC established Series A, Series B and Series C Units. Series B Units were generally intended to be used as incentives for Talos Energy LLC employees. Series B Units do not participate in distributions prior to vesting or until Series A Units have received cumulative distributions equal to (i) the original cash contributed to the Company for such Series A Units and (ii) an 8% return, compounded annually (the “Aggregate Series A Payout”), and Series C Units have received no distributions. In connection with the Transactions, the Series A, Series B and Series C Units were exchanged for an equivalent number of units in each of an entity affiliated with the Apollo Funds and an entity affiliated with the Riverstone Funds, each of which hold Common Stock of the Company. The modification did not result in incremental value to the Series B Units.

For accounting and financial reporting purposes, the Series B Units are deemed to be equity awards, and the compensation expense related to these awards is recorded on a straight-line basis over the vesting period in the Company’s Consolidated Financial Statements and is reflected as a corresponding credit to “Accumulated deficit” on the Consolidated Balance Sheets.

The Company’s unrecognized compensation expense at December 31, 2020 is approximately $3.4 million, which will be recognized upon an Aggregate Series A Payout.

New Talos Energy LLC Series B Units

In connection with the transactions contemplated in the Exchange Agreement on May 10, 2018, an entity affiliated with the Apollo Funds and an entity affiliated with the Riverstone Funds, each of which hold Common Stock in the Company as a result of the Sponsor Debt Exchange, established new Series A Units ("New Series A Units") and new Series B Units ("New Series B Units"). The New Series B Units are generally intended to be used as incentives for Talos Energy LLC employees.

The New Series B Units do not participate in distributions prior to vesting or until the New Series A Units have received cumulative distributions of $102.0 million. After issuance, 80% of the New Series B Units vest on a monthly basis over a four year period based on the initial vesting schedule of the original Series B Units, subject to continued employment. All unvested New Series B Units fully vest upon the cumulative distribution of $102.0 million.

For accounting and financial reporting purposes, the New Series B Units are deemed to be equity awards, and the compensation expense related to these awards is recorded on a straight-line basis over the vesting period in the Company's Consolidated Financial Statements and is reflected as a corresponding credit to "Accumulated deficit" on the Consolidated Balance Sheets.

The New Series B Units issued were valued using the option pricing method for valuing securities. In this method, the rights and claims of each security are modeled as a portfolio of Black-Scholes-Merton call options written on the total equity of the entities affiliated with the Apollo Funds and Riverstone Funds. The total value of the equity is calculated in an iterative process that results in the New Series A Units being valued at par. The risk-free rate of interest is based on the U.S. Treasury yield curve on the grant date. The expected time to a liquidity event is based on a weighted average calculation of management's estimate considering market conditions and expectations. The expected volatility of equity is based on the volatility of the assets of similar publicly traded companies using a Black-Scholes-Merton model. The discount for lack of marketability is based on the restrictions on the New Series B Units and the volatility of the New Series B Units using a Black-Scholes-Merton model.

The Company's unrecognized compensation expense at December 31, 2020 is approximately $1.0 million, which will be recognized upon the New Series A Units receiving a cumulative distribution.

Share-based Compensation Expense, net

Share-based compensation expense associated with RSUs, PSUs and Series B Units are reflected as General administrative expense, in the statements of operations, net amounts capitalized to "Proved properties", in the Consolidated Balance Sheets. Because of the non-cash nature of share-based compensation, the expensed portion of share-based compensation is added back to net income in arriving at "Net cash provided by operating activities" in the Consolidated Statements of Cash Flows.

For the years ended December 31, 2020, 2019 and 2018, share-based compensation expense did not have an associated income tax benefit. The Company recognized the following share-based compensation expense, net for the years ended December 31, 2020, 2019 and 2018 (in thousands):

	Year Ended December 31,		
	2020	2019	2018
Talos Energy Inc. Long Term Incentive Plan	$ 16,227	$ 12,523	$ 2,091
Talos Energy LLC Series B Units	192	256	666
New Talos Energy LLC Series B Units	43	145	3,752
Total share-based compensation expense	16,462	12,924	6,509
Less: amounts capitalized to oil and gas properties	(7,793)	(5,960)	(3,616)
Total share-based compensation expense, net	$ 8,669	$ 6,964	$ 2,893

Note 9 — Income Taxes

Prior to the Stone Combination, Talos Energy LLC was a partnership for U.S. federal income tax purposes and was not subject to U.S. federal income tax or state income tax (in most states) at the entity level. As such, Talos Energy LLC did not recognize U.S. federal income tax expense or state income tax expense in most states. Talos Energy LLC's operations in the shallow waters off the coast of Mexico are conducted under a different legal form and are subject to foreign income taxes.

Income Tax Expense (Benefit)

The components of income tax expense (benefit) were as follows (in thousands):

	Year Ended December 31,		
	2020	2019	2018
Current income tax expense (benefit)			
United States	$ (499)	$ 437	$ —
Mexico	185	1,183	1,345
Total current income tax expense (benefit)	$ (314)	$ 1,620	$ 1,345
Deferred income tax expense (benefit)			
United States	$ 35,923	$ (37,131)	$ 1,064
Mexico	(26)	(630)	513
Total deferred income tax expense (benefit)	35,897	(37,761)	1,577
Total income tax expense (benefit)	$ 35,583	$ (36,141)	$ 2,922

A reconciliation of income tax expense (benefit) computed at the U.S. federal statutory tax rate to the Company's income tax expense (benefit) is as follows (in thousands, except percentages):

	Year Ended December 31,		
	2020	2019	2018
Income tax expense (benefit) at the federal statutory tax rate	$ (90,304)	$ 4,744	$ 47,137
Earnings not subject to tax	—	—	9,980
State income taxes	(14,215)	1,396	11,738
Foreign income taxes	—	—	1,008
Foreign rate differential	(1,030)	(4,948)	432
Prior year taxes	(4,237)	(1,950)	417
Other adjustments	—	137	800
Change in tax status	—	—	(35,925)
Legal entity reorganization	(17,566)	39,336	—
Change in valuation allowance	162,213	(75,196)	(32,665)
Other permanent differences	722	340	—
Total income tax expense (benefit)	$ 35,583	$ (36,141)	$ 2,922
Effective tax rate	(8.27)%	(159.99)%	1.30%

The Company's effective tax rate for the year ending December 31, 2020 differed from the federal statutory rate of 21.0% primarily due to a non-cash tax expense of $162.2 million related to the recognition of a valuation allowance for its excess federal and state deferred tax assets. This expense was partially offset by a tax benefit of $17.6 million from adopting the final regulations under Sec. 163(j) of the Internal Revenue Code for tax years ended December 31, 2018 and December 31, 2019. The adoption of the final regulations reduced the non-cash tax expense recognized in the year ending December 31, 2019 from the legal entity conversion of a partnership to a corporation. The Company's effective tax rate for the year ending December 31, 2019 differed from the federal statutory rate of 21.0% primarily due to a non-cash tax benefit of $75.2 million related to the full release of the valuation allowance for its federal and a significant portion of its state deferred tax assets. The federal and state portion of the release equals $80.2 million, partially offset by a $5.0 million increase in valuation allowance recorded against foreign deferred tax assets. Additionally, the Company recorded a tax expense of $39.3 million related to the reorganization of our subsidiaries, of which $38.9 million represents the non-cash impact from the legal entity conversion of a partnership to a corporation.

Deferred Tax Assets and Liabilities

Net deferred tax assets (liabilities) reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Significant components of deferred tax assets and liabilities were as follows (in thousands):

	Year Ended December 31,	
	2020	2019
Deferred tax assets:		
Federal net operating loss	$ 133,804	$ 131,204
Foreign tax loss carryforward	45,980	2,316
State net operating loss	25,740	24,270
Asset retirement obligations	106,604	89,059
Tax credits	522	449
Derivatives	16,346	2,794
Other well equipment inventory	9,470	10,014
Accrued bonus	3,069	3,753
Operating lease liabilities	4,904	2,317
Other	7,727	7,004
Total deferred tax assets	354,166	273,180
Valuation allowance	(178,998)	(19,118)
Total deferred tax assets, net	$ 175,168	$ 254,062
Deferred tax liabilities:		
Oil and gas properties	$ 170,596	$ 211,216
Deferred financing	1,765	3,752
Operating lease assets	1,652	1,814
Prepaid	3,216	3,419
Total deferred tax liabilities	177,229	220,201
Net deferred tax asset (liability)	$ (2,061)	$ 33,861

Net Operating Loss

The table below presents the details of the Company's net operating loss carryovers as of December 31, 2020 (in thousands):

	Amount	Expiration Year
Federal net operating losses	$ 537,938	2035 - 2037
Federal net operating losses	$ 99,223	Unlimited
Foreign tax loss carryforward	$ 153,266	2025 - 2030
State net operating losses	$ 400,568	2025 - 2040

As of December 31, 2020, the Company had U.S. federal net operating loss carryforwards ("NOLs") of approximately $637.2 million, of which $537.9 million is subject to limitation under Section 382 of the Internal Revenue Code ("IRC"). IRC Section 382 provides an annual limitation with respect to the ability of a corporation to utilize its tax attributes, against future U.S. taxable income in the event of a change in ownership. If not utilized, such carryforwards would begin to expire in 2035.

Valuation Allowance

The Company recorded a valuation allowance of $179.0 million and $19.1 million as of December 31, 2020 and 2019, respectively. Deferred income tax assets and liabilities are recorded related to NOLs and temporary differences between the book and tax basis of assets and liabilities expected to produce tax deductions and income in the future. The realization of these assets depends on recognition of sufficient future taxable income in specific tax jurisdictions in which those temporary differences or NOLs relate. In assessing the need for a valuation allowance, the Company considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized.

Through the third quarter of 2020 and year ended December 31, 2019, the Company maintained a valuation allowance related to certain state and foreign deferred tax assets. The Company did not maintain a valuation allowance against its federal deferred tax assets and a significant portion of its state deferred tax assets due to the sustained positive operating performance during the most recent three-year period and the availability of expected future taxable income. During the fourth quarter of 2020, the Company recorded a write down of oil and natural gas properties of $267.9 million, which resulted in the Company having a cumulative loss for the most recent three-year period. This objective negative evidence limits the Company's ability to consider other subjective positive evidence, such as forecasts of future taxable income. Consequently, the Company reduced the net federal and state deferred tax assets by a valuation allowance to the amount realizable without consideration of forecasted taxable income. The Company will continue to assess the valuation allowance on an ongoing basis and as such the amount of the deferred tax assets the Company considers realizable could be adjusted in future periods

Uncertain Tax Positions

The table below sets forth the beginning and ending balance of the total amount of unrecognized tax benefits. None of the unrecognized benefits would impact the effective tax rate if recognized. While amounts could change during the next 12 months, the Company does not anticipate having a material impact on its financial statements.

Balances in the uncertain tax positions are as follows (in thousands):

	Year Ended December 31,	
	2020	2019
Total unrecognized tax benefits, beginning balance	$ 791	$ 360
Increases in unrecognized tax benefits as a result of:		
Tax positions taken during a prior period	(208)	8
Tax positions taken during the current period	65	423
Settlements with taxing authorities	—	—
Lapse of applicable statute of limitations	—	—
Total unrecognized tax benefits, ending balance	$ 648	$ 791

The Company recognizes interest and penalties related to uncertain tax positions as interest expense and general and administrative expenses, respectively.

Years Open to Examination

The 2017 through 2019 tax years remain open to examination by the tax jurisdictions in which the Company is subject to tax. The statute of limitations with respect to the U.S. federal income tax returns of the Company for years ending on or before December 31, 2016 are closed (except to the extent of any NOL carryover balance).

Note 10 — Income (Loss) Per Share

Basic earnings per common share is computed by dividing net income (loss) attributable to common stockholders by the weighted average number of shares of common stock outstanding during the period. Except when the effect would be antidilutive, diluted earnings per common share includes the impact of RSUs, PSUs and outstanding warrants.

The following table presents the computation of the Company's basic and diluted income (loss) per share were as follows (in thousands, except for the per share amounts):

	Year Ended December 31,		
	2020	2019	2018(1)
Net income (loss)	$ (465,605)	$ 58,729	$ 221,540
Weighted average common shares outstanding — basic	67,664	54,185	46,058
Dilutive effect of securities	—	228	3
Weighted average common shares outstanding — diluted	67,664	54,413	46,061
Net income (loss) per common share:			
Basic	$ (6.88)	$ 1.08	$ 4.81
Diluted	$ (6.88)	$ 1.08	$ 4.81
Anti-dilutive potentially issuable securities excluded from diluted common shares(2)	5,019	4,220	3,538

(1) For the periods prior to May 10, 2018, the Company retrospectively adjusted the weighted average shares used in determining earnings per share to reflect the number of shares Talos Energy LLC received in the Stone Combination.

(2) Includes 3.5 million warrants that expired on February 28, 2021.

Note 11 — Related Party Transactions

ILX and Castex Acquisition

On February 28, 2020 the Company acquired assets and liabilities at fair value from sellers that include, the Riverstone Sellers, affiliates of the Riverstone Funds, for $459.3 million (comprised of $303.1 million in net cash paid and $156.2 million in Conversion Stock). See additional details in Note 3 – *Acquisitions.*

Whistler Acquisition

On August 31, 2018, the Company acquired certain properties from Whistler Energy II Holdco, LLC, an affiliate of the Apollo Funds, for $52.6 million ($14.8 million, net of $37.8 million of cash acquired). Included in current assets acquired as of December 31, 2020 is $1.1 million in receivables from an affiliate of the Apollo Funds to reimburse the Company for certain payments made post-closing. See additional details in Note 3 – *Acquisitions.*

Equity Registration Rights Agreement

On May 10, 2018, the Company entered into a Registration Rights Agreement (the "Original Equity Registration Rights Agreement") with certain of the Apollo Funds and the Riverstone Funds, certain funds controlled by Franklin and certain clients of MacKay Shields LLC, relating to the registered resale of the Company's common stock owned by such parties as of the closing of the Stone Combination (the "Original Registrable Securities").

The Company and the Riverstone Sellers (and their designated affiliates) agreed under the Purchase Agreements to enter into an amendment to the Original Equity Registration Rights Agreement (such amendment, the "Registration Rights Agreement Amendment," and the Original Equity Registration Rights Agreement, as amended by the Registration Rights Agreement Amendment, the "Registration Rights Agreement"). The Registration Rights Agreement Amendment will add each of the Riverstone Sellers (or one or more of its designated affiliates) as parties to the Registration Rights Agreement and provide such parties with customary registration rights with respect to the Series A Convertible Preferred Stock (and Conversion Stock) (each as defined below) that the Riverstone Sellers received at the closing of the ILX and Castex Acquisition (the "New Registrable Securities" and together with the Original Registrable Securities, the "Registrable Securities"). Under the Registration Rights Agreement, the Company is required to file a shelf registration statement within 30 days of the Company's receipt of written request by a holder of Registrable Securities (a "Holder"). Each Holder will be limited to two demand registrations in any twelve-month period.

The Holders have the right to request that we initiate underwritten offerings of the Company's common stock; provided, that the Apollo Funds and the Riverstone Funds will have the right to demand three underwritten offerings in any twelve-month period, and Franklin and MacKay Shields will only have the collective right to demand one underwritten offering. The Holders have customary piggyback rights with respect to any underwritten offering that we conduct for as long as the Holders and their respective affiliates own 5% of the Registrable Securities. Each Holder will agree to a lock up with underwriters in the event of an underwritten offering, provided that the lock up will not apply to any Holder who does not have a right to participate in such underwritten offering. The Registration Rights Agreement has terminated with respect to Franklin and will terminate with respect to MacKay Shields in the event that MacKay Shields ceases to beneficially own 5% or more of the then outstanding shares of the Company's common stock. The Registration Rights Agreement will otherwise terminate at such time as there are no Registrable Securities outstanding.

In connection with the closing of the ILX and Castex Acquisition, and pursuant to the Purchase Agreements, as amended, the Company and ILX Holdings, LLC, ILX Holdings II, LLC, ILX Holdings III LLC and Riverstone V Castex 2014 Holdings, L.P., a Delaware limited partnership and designee of Castex Energy 2014, LLC, entered into the Registration Rights Agreement Amendment to the Registration Rights Agreement to, among other things, add each of the Riverstone Sellers (or one or more of its designated affiliates) as parties to the Registration Rights Agreement and provide such parties with customary registration rights with respect to the Company's Series A Convertible Preferred Stock issued to the Riverstone Sellers at the closing of the ILX and Castex Acquisition

The Company will bear all of the expenses incurred in connection with the offer and sale, while the Apollo Funds, the Riverstone Funds, Franklin and MacKay Shields will be responsible for paying underwriting fees, discounts and selling commissions. Fees incurred by the Company in conjunction with the Original Equity Registration Rights Agreement were $0.2 million, $0.7 million and $1.8 million for the fiscal years ended December 31, 2020, 2019 and 2018, respectively.

Stockholders' Agreement Amendment

On May 10, 2018, the Company entered into a Stockholders' Agreement (the "Stockholders' Agreement") by and among the Company and the other parties thereto. On February 24, 2020, the Company and the other parties thereto amended the Stockholders' Agreement (the "Stockholders' Agreement Amendment") to, among other things, add each of the Riverstone Sellers (or one or more of its designated affiliates) as parties to the Stockholders' Agreement and provide that for purposes of determining whether the Riverstone Sellers and their affiliates continue to satisfy certain stock ownership requirements necessary to retain their rights to nominate directors to the board of directors, the Series A Convertible Preferred Stock owned by the Riverstone Sellers was, prior to the conversion thereof, counted towards such ownership requirements on an as converted basis at the closing of the ILX and Castex Acquisition. On March 30, 2020, all 110,000 shares of Series A Convertible Preferred Stock were converted into an aggregate 11.0 million shares of the Company's common stock.

Legal Fees

The Company has engaged the law firm Vinson & Elkins L.L.P. to provide legal services. An immediate family member of William S. Moss III, the Company's Executive Vice President and General Counsel and one of its executive officers, is a partner at Vinson & Elkins L.L.P. For the years ended December 31, 2020, 2019 and 2018, the Company incurred fees of approximately $3.5 million, $4.2 million and $4.4 million, respectively, of which $0.7 million, $2.3 million and $1.1 million were payable at each respective balance sheet date for legal services performed by Vinson & Elkins L.L.P.

Service Fee Agreement

The Company entered into service fee agreements with Apollo Funds and Riverstone Funds for the provision of certain management consulting and advisory services. Under each agreement, the Company paid a fee equal to the higher of (i) a certain percentage of earnings before interest, income taxes, depletion, depreciation and amortization and (ii) a fixed fee payable quarterly, provided, however, such fees did not exceed in each case $0.5 million, in aggregate, for any calendar year. For the years ended December 31, 2020, 2019 and 2018, the Company incurred approximately nil, nil and $0.5 million, respectively, for these services. These fees are recognized in "General and administrative expense" on the Consolidated Statements of Operations. In connection with the Stone Combination on May 10, 2018, the Service Fee Agreement was terminated.

Debt Modification Work Fees

In 2018, the Company paid $9.3 million in work fees to holders of the 11.00% Bridge Loans and 7.50% Notes to exchange into 11.00% Notes as a result of the Stone Combination. The Apollo Funds and Riverstone Funds received $4.1 million and the Franklin Noteholders and McKay Noteholders received $3.3 million as a result of the work fees paid.

Note 12 — Commitments and Contingencies

Legal Proceedings and Other Contingencies

The Company is named as a party in certain lawsuits and regulatory proceedings arising in the ordinary course of business. The Company does not expect that these matters, individually or in the aggregate, will have a material adverse effect on its financial condition.

Performance Obligations

Regulations with respect to offshore operations govern, among other things, engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of wells, removal of facilities and to guarantee the execution of the minimum work program under the Mexico production sharing contracts. As of December 31, 2020 and 2019, the Company had secured performance bonds totaling approximately $651.8 million and $637.3 million, respectively. As of December 31, 2020 and 2019, the Company had $13.6 million and $13.6 million, respectively, in letters of credit issued under its Bank Credit Facility.

The table below summarizes the Company's total minimum commitments associated with vessel commitments and purchase obligations as of December 31, 2020 (in thousands):

	2021	2022	2023	2024	Thereafter	Total
Vessel Commitments[1]	$ 800	$ —	$ —	$ —	$ —	$ 800
Committed purchase orders[2]	2,165	—	—	—	—	2,165
Total	$ 2,965	$ —	$ —	$ —	$ —	$ 2,965

(1) Includes vessel commitments the Company will utilize for certain deep water well intervention and decommissioning activities. These commitments represent gross contractual obligations and accordingly, other joint owners in the properties operated by the Company will be billed for their working interest share of such costs.

(2) Includes committed purchase orders to execute planned future drilling and completion activities. These commitments represent gross contractual obligations and accordingly, other joint owners in the properties operated by the Company will be billed for their working interest share of such costs.

Note 13 —Selected Quarterly Financial Data (Unaudited)

Unaudited quarterly financial data are as follows (in thousands):

	March 31	June 30	September 30	December 31
Quarter Ended 2020				
Revenues	$ 187,764	$ 88,874	$ 135,137	$ 175,711
Write-down of oil and natural gas properties	$ 57	$ —	$ —	$ 267,859
Operating income (expense)	$ (4,212)	$ (94,603)	$ (37,059)	$ (285,436)
Price risk management activities income (expense)	$ 243,217	$ (68,682)	$ (19,882)	$ (66,968)
Net income (loss)	$ 157,749	$ (140,611)	$ (52,000)	$ (430,743)
Net income (loss) per common share:				
Basic	$ 2.71	$ (2.14)	$ (0.73)	$ (5.73)
Diluted	$ 2.69	$ (2.14)	$ (0.73)	$ (5.73)
Weighted average common shares outstanding:				
Basic	58,240	65,807	71,286	75,199
Diluted	58,572	65,807	71,286	75,199
Quarter Ended 2019				
Revenues	$ 178,713	$ 286,810	$ 228,857	$ 233,240
Operating income	$ 18,369	$ 94,872	$ 52,883	$ 46,970
Price risk management activities income (expense)	$ (109,579)	$ 29,990	$ 43,760	$ (59,508)
Net income (loss)	$ (109,636)	$ 94,764	$ 73,297	$ 304
Net income (loss) per common share:				
Basic	$ (2.02)	$ 1.75	$ 1.35	$ 0.01
Diluted	$ (2.02)	$ 1.74	$ 1.35	$ 0.01
Weighted average common shares outstanding:				
Basic	54,156	54,178	54,200	54,203
Diluted	54,156	54,451	54,430	54,559

Note 14 —Supplemental Oil and Gas Disclosures (Unaudited)

Capitalized Costs

Aggregate amounts of capitalized costs relating to oil, natural gas and NGL activities and the aggregate amount of related accumulated depletion and amortization as of the dates indicated are presented below (in thousands):

	Year Ended December 31,	
	2020	2019
Proved properties	$ 4,945,550	$ 4,066,260
Unproved oil and gas properties, not subject to amortization[1]	254,994	194,532
Total oil and gas properties	5,200,544	4,260,792
Less: Accumulated depletion	(2,680,254)	(2,051,856)
Net capitalized costs	$ 2,520,290	$ 2,208,936
Depletion and amortization rate (Per Boe)	$ 31.42	$ 18.05

(1) Amount includes $121.7 million and $106.9 million of unproved properties, not subject to amortization related to the Company's Mexico properties for the years ended December 31, 2020 and 2019, respectively.

Included in the depletable basis of proved oil and gas properties is the estimate of the Company's proportionate share of asset retirement costs relating to these properties which are also reflected as "Asset retirement obligations" in the accompanying Consolidated Balance Sheets. At December 31, 2020 and 2019, the Company's liability for oil and gas asset retirement obligations totaled $442.3 million and $369.5 million, respectively.

Costs Incurred for Property Acquisition, Exploration and Development Activities

The following table reflects the costs incurred in oil, natural gas and NGL property acquisition, exploration and development activities during the years indicated (in thousands). Costs incurred also include new asset retirement obligations established in the current year, as well as increases or decreases to the asset retirement obligations resulting from changes to cost estimates during the year.

	Year Ended December 31,		
	2020	2019	2018
Property acquisition costs:			
Proved properties	$ 422,833	$ 27,660	$ 850,515
Unproved properties, not subject to amortization	95,242	16,062	65,063
Total property acquisition costs	518,075	43,722	915,578
Exploration costs[1]	59,422	209,161	93,780
Development costs	362,011	292,547	215,467
Total costs incurred	$ 939,508	$ 545,430	$ 1,224,825

(1) Amount includes $14.6 million, $74.2 million and $16.9 million of exploration costs related to the Company's Mexico properties for the year ended December 31, 2020, 2019 and 2018, respectively.

Estimated Quantities of Proved Oil, Natural Gas and NGL Reserves

The Company employs full-time experienced reserve engineers and geologists who are responsible for determining proved reserves in compliance with SEC guidelines. There are numerous uncertainties inherent in estimating quantities of proved reserves and projecting future rates of production and timing of development expenditures. The reserve data in the following tables only represent estimates and should not be construed as being exact. Engineering reserve estimates were prepared based upon interpretation of production performance data and sub-surface information obtained from the drilling of existing wells. The Company's Director of Reserves, internal reservoir engineers and geologists analyzed and prepared reserve estimates on all oil and natural gas fields. All of the Company's proved oil, natural gas and NGL reserves are located in the United States primarily offshore Gulf of Mexico.

At, December 31, 2020, 2019 and 2018, 100% of proved oil, natural gas and NGL reserves attributable to all of the Company's oil and natural gas properties were estimated and compiled for reporting purposes by the Company's reservoir engineers and audited by Netherland, Sewell & Associates, Inc. ("NSAI"), independent petroleum engineers and geologists.

The following table presents the Company's estimated proved reserves at its net ownership interest:

	Oil (MBbls)	Gas (MMcf)	NGL (MBbls)	Oil Equivalent (MBoe)
Total proved reserves at December 31, 2017	72,804	127,656	6,547	100,625
Revision of previous estimates	2,595	(37,933)	3,187	(539)
Production	(11,771)	(22,771)	(1,176)	(16,742)
Purchases of reserves	44,788	95,661	2,074	62,806
Extensions and discoveries	4,123	8,411	64	5,589
Total proved reserves at December 31, 2018	112,539	171,024	10,696	151,739
Revision of previous estimates	(5,553)	(15,898)	(1,237)	(9,440)
Production[(1)]	(13,844)	(23,306)	(1,228)	(18,956)
Purchases of reserves	2,094	2,626	130	2,662
Extensions and discoveries	11,518	21,552	620	15,730
Total proved reserves at December 31, 2019	106,754	155,998	8,981	141,735
Revision of previous estimates	(14,633)	(56,358)	(168)	(24,195)
Production	(13,665)	(28,652)	(1,559)	(19,999)
Purchases of reserves	26,903	181,872	3,528	60,743
Extensions and discoveries	3,948	4,348	76	4,749
Total proved reserves at December 31, 2020	109,307	257,208	10,858	163,033
Total proved developed reserves as of:				
December 31, 2018	85,530	131,364	8,104	115,528
December 31, 2019	72,016	115,381	6,733	97,979
December 31, 2020	85,007	204,054	8,104	127,120
Total proved undeveloped reserves as of:				
December 31, 2018	27,009	39,660	2,592	36,211
December 31, 2019	34,738	40,617	2,248	43,756
December 31, 2020	24,300	53,154	2,754	35,913

(1) Excludes approximately 3.0 MBoe of Mexico well test production

During 2020, proved reserves decreased by 21.3 MMBoe primarily due to a decrease of 20.0 MMBoe of production and revision to previous estimates of 24.2 MMBoe due to decrease in commodity prices and differentials. The decrease was partially offset by the addition of 60.7 MMBoe added through purchases from the ILX and Castex Acquisition, Castex Energy 2005 Acquisition and LLOG Acquisition as well as 4.7 MMBoe of estimated proved reserves from extensions and discoveries primarily from an evaluation of Green Canyon 18 and Claiborne Fields.

During 2019, proved reserves decreased by 10.0 MMBoe primarily due to a decrease of 19.0 MMBoe of production and revision to previous estimates of 9.7 MMBoe due to the Phoenix and Ram Powell Fields. The decrease was partially offset by the addition of 15.7 MMBoe of estimated proved reserves from extensions and discoveries primarily from an evaluation of Green Canyon 21, Pompano, and Ewing Bank 305 as well as 3.0 MMBoe added through purchases from the Gunflint Acquisition.

During 2018, the Company added 51.1 MMBoe of estimated proved reserves, which included 62.8 MMBoe added through purchases of 59.3 MMBoe from the Stone Combination and 3.5 MMBoe from the Whistler Acquisition. The Company also added 5.6 MMBoe of estimated proved reserves from extensions and discoveries primarily from an evaluation of Green Canyon Block 18. The increase was partially offset by a decrease of 16.7 MMBoe of production.

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

The following table reflects the standardized measure of discounted future net cash flows relating to the Company's interest in proved oil, natural gas and NGL reserves (in thousands):

	Year Ended December 31,		
	2020	2019	2018
Future cash inflows	$ 4,927,497	$ 7,151,875	$ 8,654,631
Future costs:			
Production	(1,105,211)	(1,633,432)	(1,740,850)
Development and abandonment	(1,236,874)	(1,464,270)	(1,349,005)
Future net cash flows before income taxes	2,585,412	4,054,173	5,564,776
Future income tax expense	(141,515)	(662,317)	(862,473)
Future net cash flows after income taxes	2,443,897	3,391,856	4,702,303
Discount at 10% annual rate	(538,963)	(854,261)	(1,362,057)
Standardized measure of discounted future net cash flows	$ 1,904,934	$ 2,537,595	$ 3,340,246

Future cash inflows are computed by applying SEC Pricing to year-end quantities of proved reserves. The discounted future cash flow estimates do not include the effects of derivative instruments. See the following table for base prices used in determining the standardized measure:

	Year Ended December 31,		
	2020	2019	2018
Oil price per Bbl	$ 39.47	$ 61.01	$ 69.42
Natural gas price per Mcf	$ 1.97	$ 2.59	$ 3.08
NGL price per Bbl	$ 9.89	$ 26.17	$ 29.50

Future net cash flows are discounted at the prescribed rate of 10%. Actual future net cash flows may vary considerably from these estimates. Although the Company's estimates of total proved reserves, development costs and production rates were based on the best information available, the development and production of oil and gas reserves may not occur in the periods assumed. Actual prices realized, costs incurred and production quantities may vary significantly from those used. Therefore, such estimated future net cash flow computations should not be considered to represent the Company's estimate of the expected revenues or the current value of existing proved reserves.

Changes in Standardized Measure of Discounted Future Net Cash Flows

Principal changes in the standardized measure of discounted future net cash flows attributable to the Company's proved oil, natural gas and NGL reserves are as follows (in thousands):

	Year Ended December 31,		
	2020	2019	2018
Standardized measure, beginning of year	$ 2,537,595	$ 3,340,246	$ 1,807,669
Sales and transfers of oil, net gas and NGLs produced during the period	(339,557)	(665,226)	(727,969)
Net change in prices and production costs	(1,468,304)	(849,696)	1,578,330
Changes in estimated future development costs	32,589	(75,564)	32,328
Previously estimated development costs incurred	46,143	117,049	45,937
Accretion of discount	299,302	392,526	180,767
Net change in income taxes	361,875	129,590	(585,017)
Purchases of reserves	730,611	75,009	943,519
Extensions and discoveries	71,589	306,515	148,068
Net change due to revision in quantity estimates	(309,338)	(199,576)	190,853
Changes in production rates (timing) and other	(57,571)	(33,278)	(274,239)
Standardized measure, end of year	$ 1,904,934	$ 2,537,595	$ 3,340,246

Note 15 —Subsequent Events

Debt

For additional information, see Note 7 – *Debt.*

CORPORATE OFFICERS

TIMOTHY S. DUNCAN
President and Chief Executive Officer

JOHN A. PARKER
Executive Vice President – Exploration

ROBERT D. ABENDSCHEIN
Executive Vice President and
Head of Operations

SHANNON E. YOUNG, III
Executive Vice President
and Chief Financial Officer

WILLIAM S. MOSS III
Executive Vice President
and General Counsel

JOHN B. SPATH
Senior Vice President – Drilling
and Production Operations

SERGIO L. MAIWORM JR.
Vice President – Finance,
Investor Relations and Treasurer

DEBORAH HUSTON
Vice President and Deputy General Counsel

C. GORDON LINDSEY
Vice President - Corporate Development

ROBERT SHENINGER
Vice President – Health, Safety,
Environmental and Sustainability

LOREN LONG
Vice President - Mexico

BOARD OF DIRECTORS

NEAL P. GOLDMAN[1]
Managing Member, SAGE Capital
Investments, LLC

TIMOTHY S. DUNCAN
President and Chief Executive Officer
Talos Energy Inc.

CHRISTINE HOMMES
Partner, Apollo Global Management, LLC

JOHN BRAD JUNEAU
Sole Manager and General Partner,
Juneau Exploration, L.P

DONALD R. KENDALL, JR
Director and Chief Executive Officer,
Kenmont Capital Partners

RAJEN MAHAGAOKAR
Principal, Riverstone Holdings LLC

CHARLES M. SLEDGE
Retired Chief Financial Officer,
Cameron International

ROBERT M. TICHIO
Partner, Riverstone Holdings LLC

JAMES M. TRIMBLE
Chairman, Crestone Peak Resources

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Senior Partner, Apollo Global
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Symbol: TALO

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May 11, 2021
10:00 a.m. CT
Three Allen Center
333 Clay St., Suite 3300
Houston, TX 77002

FORM 10-K
Copies of the corporation's 10-K
are available on our website at
www.talosenergy.com

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