Strong Sustainable Growth

2018 ANNUAL REPORT

TALOS ENERGY

Talos Energy is an independent oil and gas company led by a management team with decades of experience in offshore exploration and production. We are experts at acquiring operated shelf and developed deepwater assets in the Gulf of Mexico, then exploring, exploiting and optimizing those assets using innovative techniques and cutting-edge seismic technologies.

NYSE: TALO

2018 was a historic year for Talos Energy as we completed and fully integrated our transformative merger with Stone Energy. The merger significantly expanded the scale and operational breadth of Talos, and its benefits were immediately noticeable.

Additionally, the merger set the stage for us to more broadly share our story and values as a publicly-traded company focused on positive free cash flow, moderate, sustainable growth and balance sheet discipline. In 2018, Talos delivered solid financial performance and successfully executed on a number of complex projects and we expect more of the same in 2019 and beyond.

We also believe in our differentiated strategy, which we have refined and validated over nearly two decades. We leverage our deep understanding of the basins in which we operate, the US Gulf of Mexico (“GOM”) and offshore Mexico, to identify and execute on highly economic drilling projects. In the US GOM, we are able to capitalize on the ample infrastructure and premium commodity pricing closely tied to Brent, and the current market environment further allows us to engage in low cost acquisitions and infrastructure-led exploration and exploitation with conventional offshore wells. These conventional wells boast lower initial declines as compared to onshore shale projects. Complimenting these more mature assets, offshore Mexico provides Talos early access to an emerging basin with a significant resource base in shallow water depths that allows for low oil price break-evens and facilitates shorter development cycles. I believe our portfolio of assets will allow Talos to continue to grow at a measured pace in the US GOM while continuing to generate positive free cash flow, with the initiation of production from our offshore Mexico assets driving a step-change in Talos’s production and cash flows in the future.

As we conduct our operations, we continue to live by the highest standards of health, safety and environmental focus and stewardship. We believe in and support the communities along the coasts of both countries in which we operate, and we appreciate and deeply value the symbiotic relationship that we have with these communities.

Quality Asset Base

Talos has a solid asset base from which to grow our company. We are currently executing on projects that will further stabilize our production base and add significant new volumes in 2019. In addition, I’m very excited about numerous drilling prospects that we have identified and are currently evaluating. Some of these prospects are on previously held Talos leases while others have been added through our targeted business development efforts.

Upon closing of the merger with Stone, we focused on lower-risk but high impact projects that could grow production in 2018 while also positioning the company for sustainable growth and maintaining our ability to generate positive free cash flow for years to come. And our team has delivered on these goals to date. Our 2018 production was approximately 5% higher than pro forma 2017 Talos and Stone production and we increased Proved Developed reserves by 20%, as compared to our pro forma reserves as of December 31, 2017.

In November 2018, we initiated the appraisal of the Zama discovery in offshore Mexico. I am extremely proud of our team for the operational excellence they have achieved in Mexico as we continue to safely execute the project ahead of schedule and under budget.

Our Proved Reserves as of December 31, 2018 were 151.7 MMBoe, and the present value of these reserves discounted at 10% was $3.9 billion on a pre-tax basis. Approximately 80% of these reserves reside in our US GOM deepwater assets. Importantly, the Zama discovery in offshore Mexico is not yet included in our proved reserves, per SEC guidelines, until we reach a Final Investment Decision (“FID”).

Low Entry Cost M&A and Best Practices Seismic Reprocessing Leads to Better Drilling Economics

A key aspect of our strategy is the variety of low cost business development opportunities that are available to us. Talos is well-positioned as a credible consolidation candidate in the US GOM and is ready to capitalize on the lower valuation market dynamics driven by the over-allocation of capital in various onshore shale plays and the resulting underinvestment in offshore projects. We were able to exploit some consolidation opportunities in

We continue to live by the highest standards of health, safety and environmental focus and stewardship.

– Timothy S. Duncan

2018 by closing three small bolt-on transactions, including the Ram Powell and Gunflint assets in our Mississippi Canyon core area and the Green Canyon 18 asset in our Green Canyon core area. These assets were acquired at compelling valuation metrics and add to our scalable infrastructure base upon which we will drive further growth.

Through these acquisitions we have access to underutilized production facilities. The combination of infrastructure with throughput capacity in an area where we have a deep geological expertise and our reprocessed seismic allows Talos to develop drilling opportunities with enhanced economics. For example, since the announcement of our Green Canyon 18 acquisition, we were able to acquire nearby leases with subsea prospects through the semi-annual federal lease sale, we farmed into a lease as the operator with a drill-ready prospect, and we purchased a stranded discovery from Exxon, all of which will tie into the Green Canyon 18 facility if they are successful. These business development activities around acquired infrastructure exemplify our strategy of executing low-entry cost acquisitions in order to facilitate attractive economic exploration, exploitation and development activities.

Globally Recognized Zama Discovery

We opportunistically entered offshore Mexico in the first private sector lease auction in July 2015 and competed against a number of globally recognized companies. We narrowly outbid the competitors and were awarded two Production Sharing Contracts covering a total of over 160,000 acres in Block 7 and Block 2, both in the Sureste Basin.

Our focus was on the exploration of the same geological trends that we focus on in the US GOM, which are the Lower Pliocene through the Miocene section. These geological trends have been under-explored in an otherwise prolific basin offshore Mexico. After proprietarily reprocessing the available seismic data, in 2017 we drilled the first offshore exploration well by the private sector in the history of Mexico resulting in the Zama discovery, which was awarded the worldwide Discovery of the Year by Wood Mackenzie. This is an extremely prestigious honor for Talos and validates our ability to execute once-in-a-generation projects. Projects like Zama serve to propel Talos forward as a competitive force and an industry leader.

In 2018, we commenced our appraisal program on the Zama discovery, which includes three reservoir penetrations that we expect will advance our progress toward FID in 2020. Our first penetration was successful and in line with our expectations, thus validating our geophysical models. The appraisal program is expected to conclude by mid-year 2019.

Building for the Future

I believe Talos maintains all of the critical elements necessary to continue to drive material, long-term value creation for our shareholders. The company's strategy has been validated through multiple commodity cycles by focusing on an environment we know best, being both patient and opportunistic, and conservatively managing cash flow and leverage to protect our balance sheet and capital program. Today, I am very proud that Talos has been able to generate positive free cash flow while so many companies in our industry have not been able to do so. We have also accumulated a deep inventory of highly economic projects and a globally recognized discovery in Zama, maintained a conservative balance sheet and established ourselves as a trusted counterparty to transact with. We believe that we have established a great foundation to build on.

In 2018, we asked a lot of our team. We successfully integrated a significant merger while simultaneously taking our first steps as a publicly-traded company. We balanced a series of challenging projects and acquisitions that helped expand the scale of our business. And we advanced our world-class Zama discovery towards future FID on schedule. Throughout all of these activities, we proved we can reliably generate positive free cash flow, maintain appropriate debt and liquidity metrics and deliver operationally. I am pleased with all that Talos has accomplished in 2018, but we're already looking ahead. I am truly excited about what the future holds.

Sincerely Yours,

Timothy S. Duncan
President and Chief Executive Officer

OUR CULTURE

Talos is a growing company that fosters an entrepreneurial culture of development.

We pair the proficiency of our geological and engineering staff with cutting-edge science and technology. By combining the influence of refined data and the transfer of knowledge and best practices, we enrich our ability to access hydrocarbon reservoirs more safely, resourcefully and in a manner that protects both the public and the environment.

The safety, health and welfare of employees, contractors, visitors and the public is our number one priority and foremost core value. Talos offers competitive benefits, flexible work schedules to promote work/life balance, opportunities for advancement and much more.

Every year since our inception, Talos has been ranked a Top Workplace on the Houston Chronicle Top Workplaces list. We strive to make a positive impact on our local community through our Community Committee. Our community matters greatly to us, and has given our employees so much that we feel it's our responsibility to give back. We offer a $500 annual allowance for each employee that can be used towards a not-for-profit organization of their choice. Whether it be a community fundraiser, a child's athletic team, or a cause-worthy donation, our employees know Talos stands behind them.

In addition, we also hold quarterly events with national and local organizations such as Houston Children's Charity, Houston Food Bank and Oilfield Helping Hands in order to provide direct opportunities for our employees to make a difference.

HSE AT TALOS ENERGY:

2018 was an exciting year for Talos. We acquired new key assets, added talent and solidified our position as one of the premier operators in the Gulf of Mexico. As a premier operator, it is our duty to provide a safe environment for all employees and contractors who work for us. We define safety as freedom from unacceptable risk of harm. We are also obligated to be stewards of the environment and take consistent sustainable measures to avoid any adverse environmental impacts.

HSE will always be the top priority at Talos; while compliance, production and cost are part of our core business priorities, we cannot compromise HSE for any reason.

KEY 2018 TALOS HSE ACCOMPLISHMENTS INCLUDE:

» Successful integration of multiple HSE Management Systems (i.e. Stone, Whistler) into one consolidated SEMS and Talos Safe Operating Practices (TSOP) program

» Best in class INC and component ratio include a 22% drop in the rolling average during the course of the year

» Delivery and completion of Talos-specific eLearning to all offshore employees and contractors with a permanently assigned rotation

» HSE expectations and deliverables, integrated into the front-end of projects through HAZID/HAZOPS, DWOPS and project-specific HSE plans

» Processes developed to verify corrective or preventive actions from Lessons Learned have been applied in the field

» Mexico Risk Management Plan approved by ASEA for the Zama appraisal program

» Initiated formalized HSE reviews with high-risk and key contractors – predominantly crane and ARO companies

Phoenix Complex

The Phoenix Complex, located in our Green Canyon core area, is the biggest producing asset in our portfolio. The complex includes the Tornado field, which Talos discovered in 2016. Following the discovery, Talos drilled a second well in the field and began production from it in December 2017. In December of 2018, Talos successfully drilled the third well in the Tornado field and expects to commence production during the second quarter of 2019.

Production from the Phoenix Complex flows to the Helix Producer-1 ship, which successfully completed its regulatory dry-dock in the first quarter of 2019. In addition to Tornado 3, we also drilled the Boris 3 well in January of 2019, which we also expect to commence production during the second quarter of 2019.

Average production from the Phoenix Complex in 2018 was approximately 17,900 Boe per day and as of December 31, 2018, the proved reserves were 63.9 MMBoe, of which 78% was oil and 86% was liquids.

Pompano and Amberjack

Pompano and Amberjack were acquired as part of the merger with Stone Energy, and they provide a solid foundation for growth in the area. In July of 2018, Talos commenced production from the Mt. Providence well, which was a subsea tieback to the Pompano production facility.

From the closing of the Stone Energy merger to December 31, 2018, average production from the Mississippi Canyon core area was approximately 12,555 Boe per day, and as of December 31, 2018, the proved reserves were 36.4 MMBoe, of which 83% was oil and 87% was liquids.

Ram Powell

Ram Powell was acquired from subsidiaries of Royal Dutch Shell, ExxonMobil Corporation and Anadarko Petroleum Corporation in May of 2018, immediately prior to the closing of the merger with Stone Energy. The asset is located in a strategic area of the US Gulf of Mexico where oil discoveries have been made in recent years. Talos expects to commence an exploration and exploitation drilling campaign around Ram Powell in the coming years.

Average production from Ram Powell in 2018, from the closing of the Stone Energy merger to December 31, 2018, was approximately 7,856 Boe per day. As of December 31, 2018, proved reserves were 18.1 MMBoe, of which 59% was oil and 72% was liquids.

Block 7 – Zama Discovery

Block 7 was awarded to Talos in 2015 as part of the first Mexican auction to the private sector in 80 years. In 2017, Talos drilled and discovered the Zama field, which was elected the "Discovery of the Year" by two different organizations, including Wood Mackenzie. In 2018, Talos commenced the appraisal of the Zama Discovery, which confirmed our geological, geophysical and reservoir modeling estimations.

Talos estimates that the Zama field will contain 400-800 MMBoe of recoverable resources.

Prospects | Discovery | Drilled | Future Drilling

OUR TIMELINE

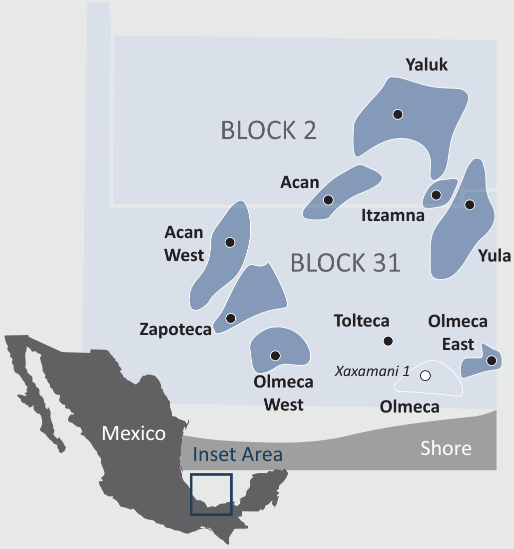
2015	2017	2018	2019	2020	2022
» Awarded Block 7 PSC	» Zama Discovery	» Zama Appraisal » Pre-Unitization Agreement with Pemex	» Finalize Zama Appraisal » Conclude Unitization Agreement with Pemex	» Final Investment Decision	» First Oil

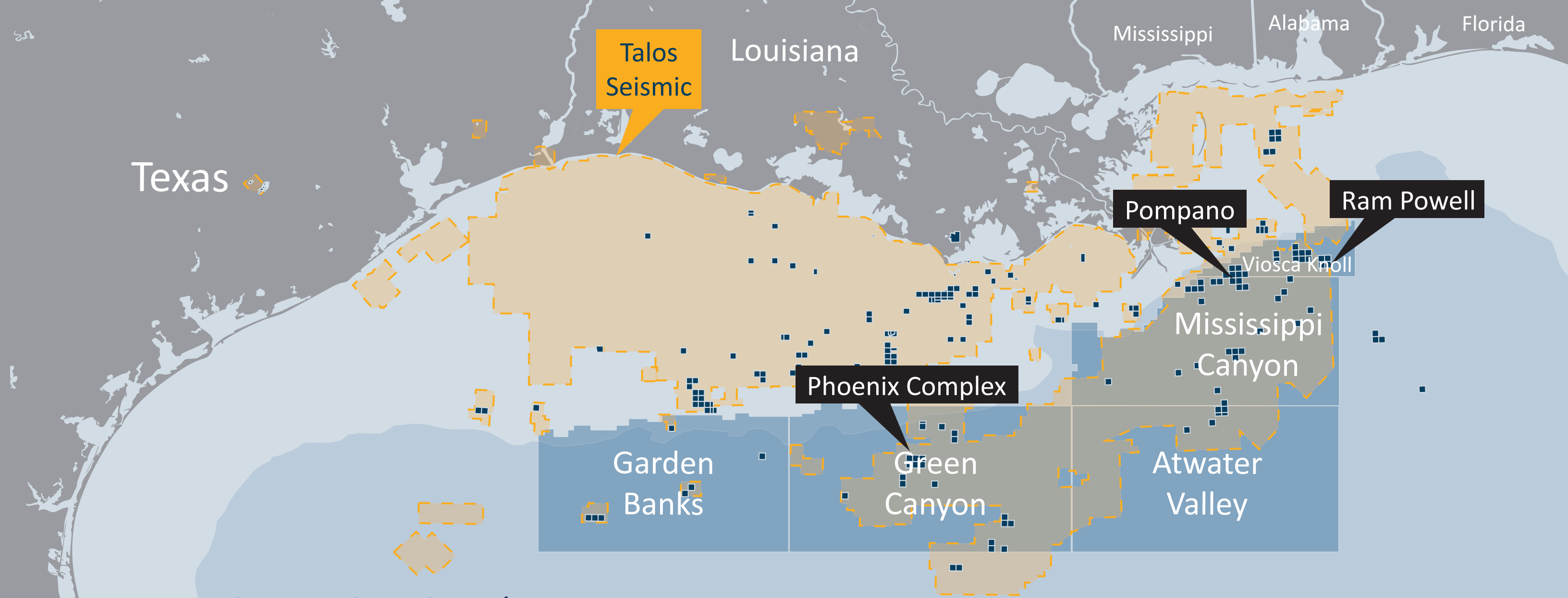
Block 2/31

Talos was awarded the Block 2 Production Sharing Contract in 2015. In 2018, Talos signed a cross-assignment of interest with a subsidiary of Pan American Energy to acquire 25% in Block 31, in exchange for 25% in Block 2 to Pan American, subject to government approvals.

In 2018, Talos concluded its technical study of Blocks 2 and 31. In 2019, we expect to drill four wells in the area. Of those, the Olmeca project has been de-risked by a Pemex well drilled in 2003. The 2019 drilling campaign will appraise the same geological structure initially tested by Pemex.

Prospects | Drilled | Future Drilling





FINANCIAL HIGHLIGHTS[1]

YEAR ENDED (IN THOUSANDS)	2018 PRO FORMA[2]	2018	2017	2016
Revenues	$ 1,013.2	$ 891.3	$ 412.8	$ 258.8
Net Income (Loss)	274.6	221.5	(62.9)	(208.1)
Capital Expenditures	452.4	390.6	227.2	145.8
Total Long-term Debt[3]	766.2	766.2	697.6	701.2

RESERVES (MMBOE)				
Proved Developed Producing (PDP)	78.1	78.1	31.8	39.7
Proved Developed Non-Producing (PDNP)	37.5	37.5	21.9	26.1
Proved Developed	115.5	115.5	53.7	65.8
Proved Undeveloped (PUD)	36.2	36.2	46.9	37.9
Total Proved	**151.7**	**151.7**	**100.6**	**103.7**

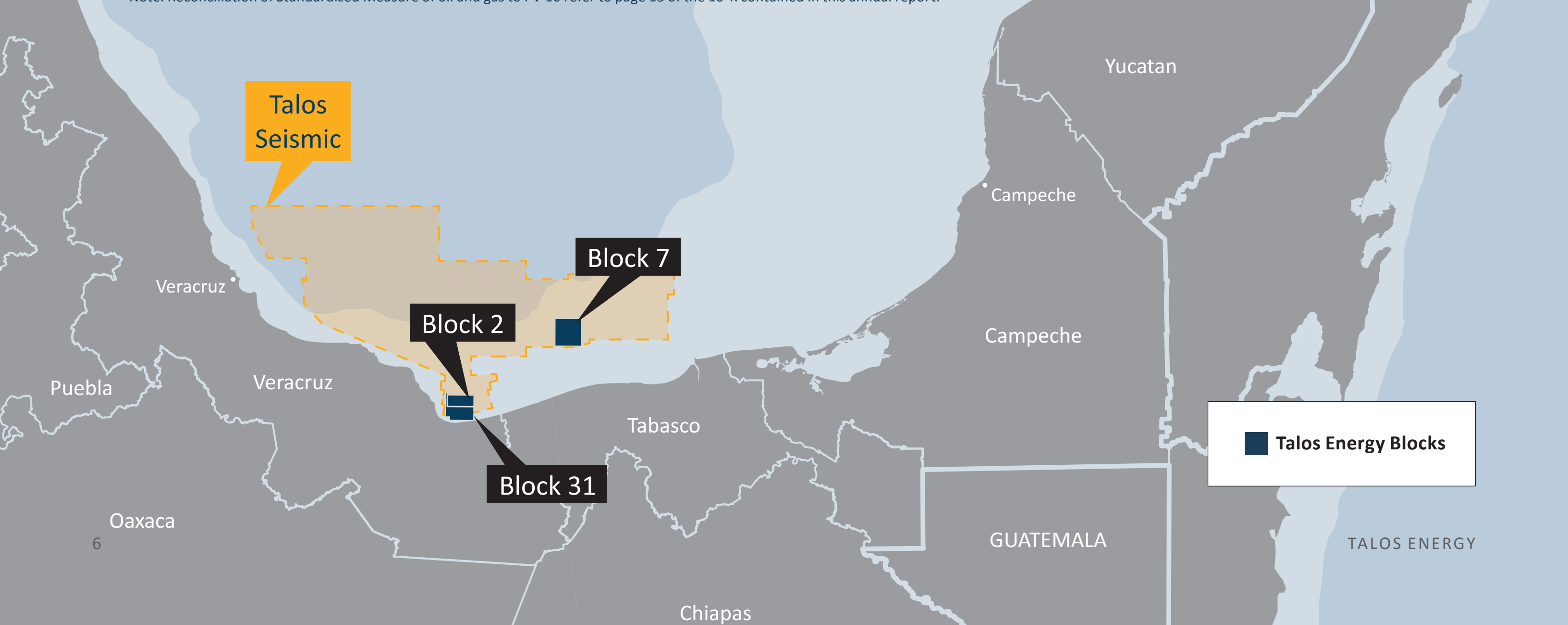
PRODUCTION				
Sales volume (MMBoe)	19.1	16.7	10.5	8.9
Average daily production (MBoe/d)	52.4	45.9	28.7	24.4

[1] For financial reporting treatment of business combination, please refer to pages 63, 66 and F-9 of the 10-K document contained in this annual report.

[2] Refers to the combined performance of Talos and Stone from January 1, 2018, with the addition of Ram Powell from closing of that acquisition on May 1, 2018.

[3] Inclusive of Capital Lease.

Note: Reconciliation of Standardized Measure of oil and gas to PV-10 refer to page 15 of the 10-K contained in this annual report.



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, 2018

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 01-38497

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

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

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

Securities registered pursuant to Section 12(b) of the Act: Common Stock, Par Value $0.01 Per Share; Common stock traded on the NYSE stock market

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

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

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

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the 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 NYSE Stock Market on June 30, 2018, was $281,311,750.

The number of shares of registrant's Common Stock outstanding as of March 6, 2019 was 54,155,805.

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

TABLE OF CONTENTS

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 ("Btus").

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 Securities and Exchange Commission 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 Securities and Exchange Commission 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 Securities and Exchange Commission 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, 2018 and ending December 1, 2018, adjusted by lease for market differentials (quality, transportation, fees, energy content, and regional price differentials). The Securities and Exchange Commission 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 year ending December 31, 2018, we were subject to U.S. federal and state income taxes at the entity level. For the tax years ending December 31, 2017 and 2016, we were not subject to U.S. federal or state income taxes (in most states) at the entity level and thus made no provision for U.S. federal or state income taxes in the calculation of our standardized measure. Standardized measure does not give effect to derivative transactions.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and 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 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, inflation, lack of availability of drilling and production equipment and services, 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 the business combination between Talos Energy LLC and Stone Energy Corporation, the possibility that the anticipated benefits of such 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 the two companies, 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.

PART 1

Items 1. Business

Overview

We are a technically driven independent exploration and production company with operations in the United States Gulf of Mexico and offshore Mexico. Our focus in the United States Gulf of Mexico is the acquisition of deep water assets with existing infrastructure and the exploration, exploitation and development of such assets in key geological trends. Offshore Mexico provides us high impact exploration opportunities in an oil rich emerging basin. We use our access to an extensive seismic database and our deep technical expertise to identify, acquire and exploit attractive assets with robust economic profiles. As of December 31, 2018, deepwater assets represent 83% of our proved reserves.

We have historically focused our operations in the Gulf of Mexico because we believe this area provides us with favorable geologic and economic conditions, including multiple reservoir formations, comprehensive geologic databases, extensive infrastructure and an attractive acquisition market and because we have significant experience and technical expertise in the basin. 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 acquisition and joint venture opportunities.

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 or are acquisition or joint venture opportunities. We add to and reevaluate our inventory in order to deploy capital as efficiently as possible.

Talos Energy Inc. was incorporated on November 14, 2017 under the laws of the state of Delaware for the purpose of effecting the previously disclosed business combination between Talos Energy LLC ("Talos Energy") and Stone Energy Corporation ("Stone"), pursuant to which each of Talos Energy 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 "Closing Date." In addition, as used in this 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 Closing Date, Talos Energy Inc. and its consolidated subsidiaries and prior to the Closing Date, Talos Energy and its consolidated subsidiaries.

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 (the "Transaction Agreement"), dated as of November 21, 2017, among Stone, Talos Energy, us and Sailfish Merger Sub Corporation ("Merger Sub"). The transactions contemplated by the Transaction Agreement were accounted for as a business combination in accordance with accounting principles generally accepted in the United States of America ("GAAP"), with Talos Energy 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 Talos Energy Inc. reflect the assets, liabilities and results of operations of Talos Energy (as our predecessor) prior to the Closing Date, 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 Inc. 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, our predecessor for financial reporting purposes, please read "— Talos Energy LLC." For more information on the Stone Combination, please read "— Stone Combination."

Talos Energy LLC

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

On February 3, 2012, Talos Energy 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 Talos Energy received a private equity capital commitment.

On February 6, 2013, Talos Energy acquired all of the equity of Energy Resource Technology GOM, LLC ("ERT") and its subsidiary from Helix Energy Solutions Group, Inc. ("Helix") for approximately $625.2 million (inclusive of purchase price and working capital adjustments of approximately $15.2 million), and payments for ongoing guarantees from Helix to third-parties. Additionally, Talos Energy agreed to assign Helix an overriding royalty interest in certain properties acquired in the transaction at closing. We refer to this purchase as the "ERT Acquisition." The ERT Acquisition was effective December 1, 2012 and closed on February 6, 2013. Prior to the closing of the ERT Acquisition, the Sponsors and members of management had invested an aggregate of approximately $325 million in Talos Energy to fund a portion of the ERT Acquisition as well as to fund other asset purchases.

In September 2015, Talos Energy, together with consortium partners Sierra Oil and Gas S. de R.L de C.V. ("Sierra") and Premier Oil Plc ("Premier", and together with Talos Energy and Sierra, the "Consortium") executed two Production Sharing Contracts ("PSCs") with the National Hydrocarbons Commission ("CNH"), Mexico's oil and gas regulator, for Blocks 2 and 7 of Round 1. The PSCs were awarded to the Consortium during the first tender of Mexico's oil and natural gas fields in over 80 years. Blocks 2 and 7 are located in the Sureste Basin, a prolific proven hydrocarbon province, in the shallow waters off the coast of Mexico's Veracruz and Tabasco states, respectively. Blocks 2 and 7 contain approximately 162,904 gross acres with numerous high impact prospects in well-established and emerging plays. In 2017, the Consortium drilled Zama-1, the initial exploration well in Block 7, resulting in the discovery of the Zama Field. As of December 31, 2018, we were in the process of appraising the discovery.

Stone Combination

On the Closing Date, we consummated the transactions contemplated by the Transaction Agreement and Talos Energy and Stone became our wholly-owned subsidiaries. Pursuant to the Transaction Agreement, 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 our direct wholly-owned subsidiary (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 our common stock, par value $0.01 (the "Common Stock") and (ii) the Sponsors contributed all of the equity interests in Talos Production LLC ("Talos Production") (which at that time owned 100% of the equity interests in Talos Energy) to us 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, we consummated the transactions contemplated by that certain Exchange Agreement, dated as of November 21, 2017 (the "Exchange Agreement"), among us, 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 and Talos Production Finance, Inc. (together, the "Talos Issuers") to us 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% Senior Secured Notes") and (iii) Franklin Noteholders and MacKay Noteholders exchanged their 7.50% Senior Secured Notes due 2022 issued by Stone ("7.50% Stone Senior Notes") for $137.4 million aggregate principal amount of 11.00% Senior Secured Notes.

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

Business Strategy

We intend to increase stockholder value through the following strategies:

Grow Production, Reserves and Cash Flow by Developing Our Attractive Asset Base in a Capital Efficient Manner.

Our team is focused on continuously improving capital efficiency, and we believe the combination of our experience and the existing infrastructure in the U.S. Gulf of Mexico will allow us to continue to benefit from attractive finding and development costs. We also benefit from our proven ability to increase production from legacy fields and identified projects. Furthermore, we intend to use our technical expertise and seismic database to find additional drilling projects in proximity to our existing assets.

Expand Our Reserves and Production Through Lease Acquisitions and Diversified Business Development.

We intend to deploy our expertise and seismic resources to identify and acquire attractive leasehold acreage in federal lease sales for the U.S. Gulf of Mexico. In many cases, acreage available in the federal lease sales has not been evaluated with the latest reprocessed seismic data, resulting in an opportunity for us to identify previously unknown drilling prospects. In the latest federal lease of the August 2018 sale, we were the fifth most active bidder in the U.S. Gulf of Mexico, and we were the high bidder on 14 lease blocks. During that sale, we focused on blocks that adjoin our existing properties, and we have identified specific prospects through reprocessed seismic data. In addition, our proven track record through the drillbit and our strong financial position frequently attracts potential drilling partners. Our deep industry relationships, technical expertise and extensive regional seismic database allow us to effectively identify and evaluate these third-party proposed drilling projects. We intend to continue to strategically pursue these types of drilling projects with other operators on a selected basis.

Evaluate and Pursue Accretive Acquisitions.

We intend to continue to opportunistically expand our asset base by evaluating the supply of acquisition opportunities in the U.S. Gulf of Mexico and offshore Mexico. Our acquisition strategy is focused on operated deepwater assets with a geological setting that can benefit from our ability to use our seismic database and our reprocessing expertise to re-evaluate the acquired assets. By applying our disciplined valuation methodology, we seek to reduce the risk of underperformance of the acquired properties while maintaining upside potential. In addition, we may consider acquisition opportunities in other offshore basins with analogous geologies that are suitable for our operational and technical expertise to the extent we believe they will create additional value for stockholders.

Maintain High Operatorship to Leverage Our Technical Expertise.

We operate properties that generate approximately 94% of our production, and we strive to maintain a majority of operational control over our producing properties. We believe that maintaining control of our production enables us to apply leading practices to every aspect of our operations. In addition, maintaining high operatorship allows us to leverage our technical team’s deep regional experience and modern seismic expertise in order to generate attractive investment opportunities on our properties while concurrently controlling execution. Lastly, maintaining operational control allows us to sustain our focus on maximizing our returns through reduced development cycle times and efficient capital utilization.

Properties

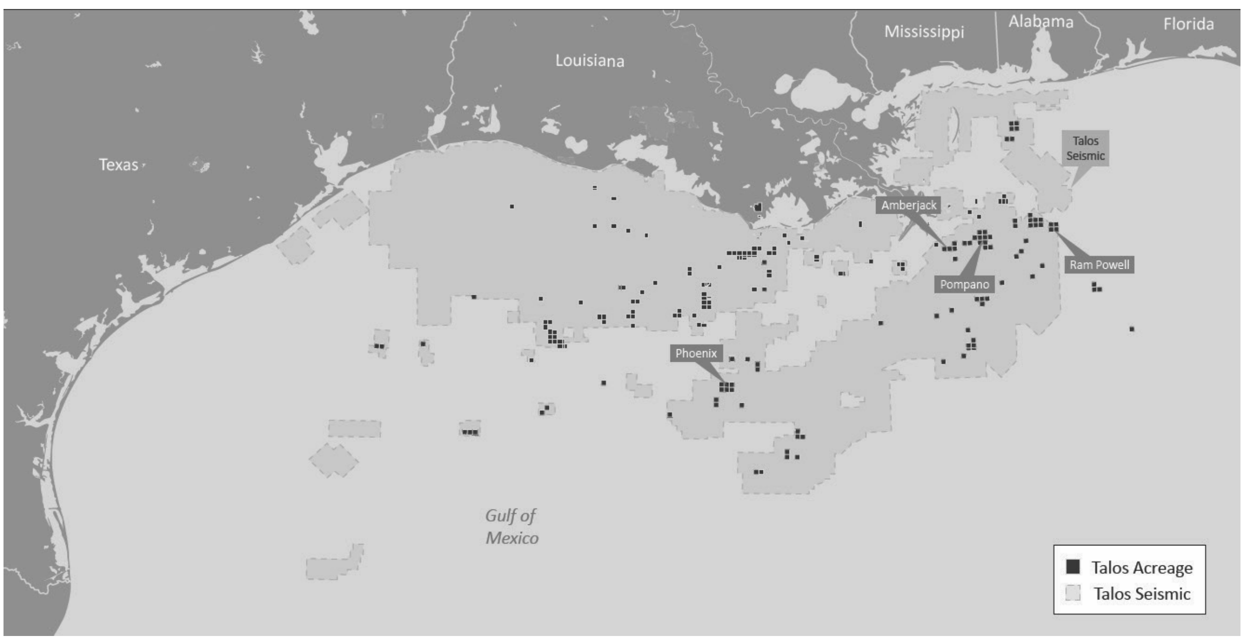
United States Gulf of Mexico Properties

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 have 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 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.

In the United States, at December 31, 2018, we had an interest in 271.0 gross producing wells (228.9 net producing wells) on 885,888 gross (624,891 net) total acres, of which 477,190 gross (342,604 net) are developed acres. We operate properties that contain 98% of our proved reserves at December 31, 2018.

At December 31, 2018, our core properties in the United States, which represent approximately 68% of our 2018 production and 78% of our December 31, 2018 proved reserves are illustrated below:



The following table sets forth certain information regarding our core properties in the United States:

Operating Area	Estimated Proved Reserves: Mboe	% Oil	% Natural Gas	% NGLs	% Proved Developed	Full Year 2018 Net Production (MBoe)[4]
United States Core Properties						
Phoenix[1]	63,931	78%	14%	8%	55%	6,536
Pompano[2]	28,206	81%	14%	5%	100%	2,486
Ram Powell	18,094	59%	28%	13%	100%	1,854
Amberjack	8,148	88%	10%	2%	100%	477
United States Core Properties Subtotal	118,379	77%	16%	7%	76%	11,353
Other United States Properties[3]	33,360	65%	30%	5%	78%	5,389
Total United States	151,739	74%	19%	7%	76%	16,742

(1) Production volumes and estimated proved reserves include the Tornado, Boris and Typhoon areas of the Phoenix Field, all of which tie back to the HP-I.

(2) Production volumes and estimated proved reserves include the Pompano and Cardona Fields, both of which tie back to the Pompano Platform.

(3) Other United States Properties includes Gulf of Mexico shelf and deepwater.

(4) Production for the Pompano, Ram Powell and Amberjack Core Properties are presented from the Closing Date of the Stone Combination through December 31, 2018.

Phoenix Field—The Phoenix Field is comprised of six operated blocks, which include Green Canyon Blocks 236, 237, 238, 280, 281, and 282, located in the deepwaters offshore Louisiana.

There are no conventional fixed or moored production platforms in the field-instead the subsea wells are tied back to a dynamically positioned floating production unit, the Helix Producer I ("HP-I"). The HP-I interconnects with the Phoenix Field through a production buoy that can be disconnected if the HP-I cannot maintain its position on station, such as the approach of a hurricane or in the event of a mechanical problem with the dynamic positioning system. There are eight active wells in the Phoenix Field and the average net daily production for the year ended December 31, 2018 was 17,907 Boepd.

Pompano Field— The Pompano Field is comprised of seven operated blocks which include Viosca Knoll Blocks 989 and 990, and Mississippi Canyon Blocks 26, 27, 28, 29 and 72 located in the deepwaters offshore Louisiana. The Pompano Field's three current subsea systems are tied back to a fixed leg platform with a total of 23 active wells. The field's average net daily production since the Closing Date of the Stone Combination was 10,534 Boepd.

Ram Powell Field— The Ram Powell Field is comprised of six operated blocks which include Viosca Knoll Blocks 911, 912, 913, 955, 956 and 957 located in the deepwaters offshore Louisiana. The Ram Powell Field has eight active dry tree wells that are located on a tension leg platform in Viosca Knoll Block 956. The field's average net daily production since the Closing Date of the Stone Combination was 7,856 Boepd.

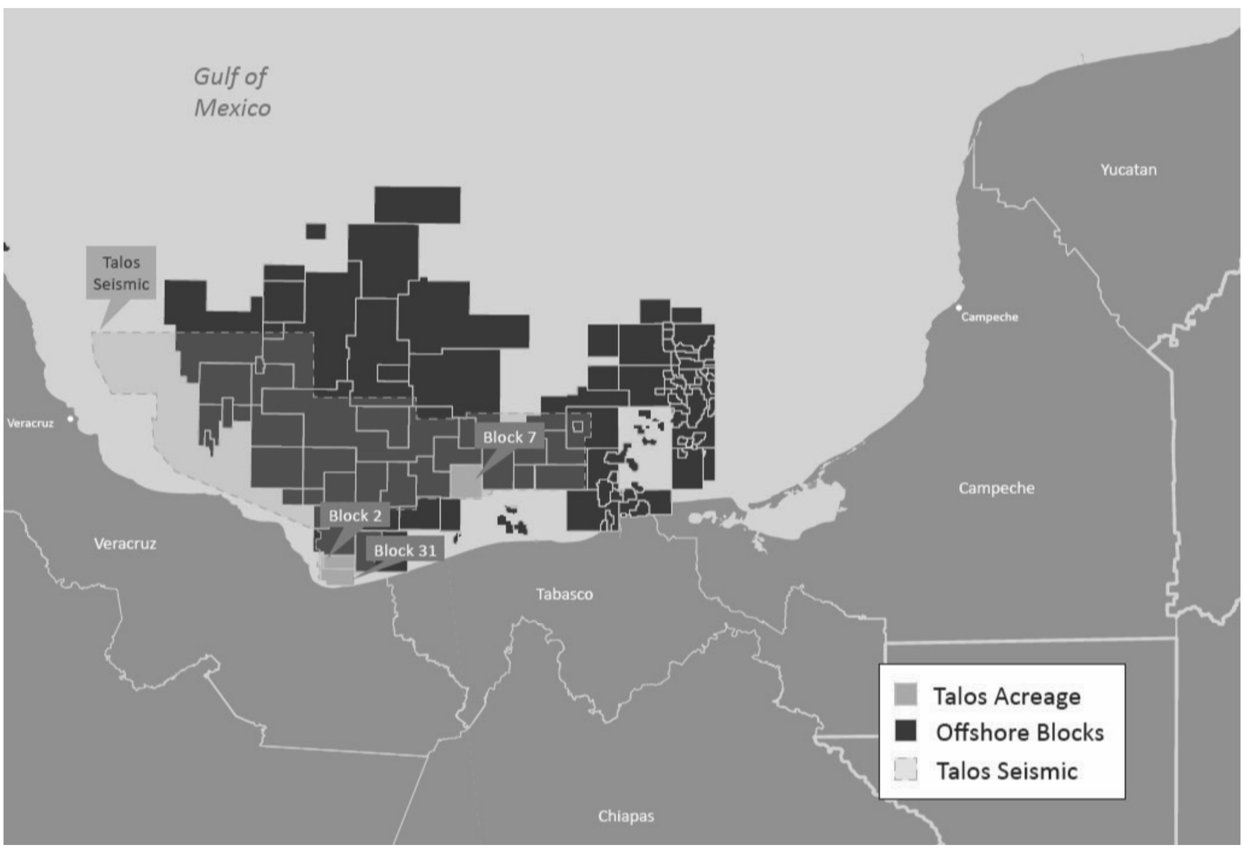
Amberjack Field—The Amberjack Field is comprised of three operated blocks which include Mississippi Canyon Block 108, 109 and 110. The Amberjack Field has 29 active conventional dry tree wells located on a fixed structure platform in Mississippi Canyon Block 109. The field's average net daily production since the Closing Date of the Stone Combination was 2,021 Boepd.

Mexico Properties

In September 2015, we, together with the Consortium, executed a PSC with the CNH for each of Blocks 2 and 7 of Round 1. The PSCs were awarded to the Consortium during the first tender of Mexico's oil and natural gas fields in over 80 years. Blocks 2 and 7 are located in the Sureste Basin, a prolific proven hydrocarbon province, in the shallow waters off the coast of Mexico's Veracruz and Tabasco states, respectively. Blocks 2 and 7 contain approximately 162,904 gross acres with numerous high impact prospects in well-established and emerging plays. Our participation interest ("PI") in Block 2 is currently 20% and our PI in Block 7 is 35%. We are the operator of Block 7.

The PSCs 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 PSCs. 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. Between 7.5% and 14% of the contractual value of the oil will be allocated to the United Mexican States in the form of a royalty, depending upon the price of a barrel of oil, with a collar between $48.00 and $100.00 per Bbl. The allocation for the royalty on natural gas is 0% when the price per MMBtu is below $5.00 and, if the natural gas price exceeds $5.00 per MMBtu, the royalty allocation percentage is calculated as the price per MMBtu divided by 100. The remaining value of the hydrocarbons after the allocation for cost recovery and royalties is considered operating profit under the PSCs. The allocation of operating profit to the Consortium after the allocation for cost recovery and royalties on Blocks 2 and 7 is 44% and 31%, respectively. Additionally, in the event that the cumulative project internal rate of return in any one month exceeds 25%, the barrels of oil allocated to the Consortium after cost recovery ("Profit Oil") is reduced on a sliding scale. The reduction in Profit Oil varies linearly between 0% and 75% of the entitled amount. The maximum 75% reduction occurs once the cumulative project internal rate of return meets or exceeds 40%.

At December 31, 2018, our core properties in Mexico are presented in the following acreage map:



- *Block 7*— In July 2017, we completed drilling operations on the offshore Mexico Zama-1 exploration well in Block 7, reaching a total depth of 13,480 feet. 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 American Petroleum Institute ("API") gravity oil. The well has been suspended as a future producer. We are now analyzing all the data gathered from the Zama-1 well and evaluating the optimal methods for appraisal and development of the discovery. These contingent resources are not included in proved reserves.

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. The Zama appraisal campaign is expected to be completed by mid-year 2019. If the appraisal of the Zama Field confirms our initial estimates, we expect to announce a Final Investment Decision in 2020, following Mexican government approval of the development plan. In addition to Zama, other prospects within Block 7 are being analyzed and matured to potentially be drilled over the next several years, assuming an extension of the Exploration Period is approved by the CHH. See Part II, Item 8. Financial Statements and Supplementary Data — Note 4 — *Property, Plant & Equipment* for further detail on Mexico properties.

Pre-Unitization Agreement with Pemex. In September 2018, we and our consortium partners in Block 7 signed a Pre-Unitization Agreement ("PUA") with Pemex Exploration 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 enables information sharing related to the Zama discovery and potential extension into Pemex's neighboring block. The PUA has been approved by the Mexican Secretariat of Energy ("SENER").

- *Block 2*—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 Block 2 and Block 31. Our assignment of a 25% PI in Block 2 to Hokchi closed on December 21, 2018, and Hokchi has assumed operator responsibilities with respect to Block 2. Hokchi's assignment of an interest in Block 31 to us will be completed upon final approval by the CNH. In addition, Premier exercised its option to reduce its PI in Block 2 to zero and assign a 5% PI to each of Sierra and us. Such assignment is also subject to CNH's approval. Upon completion of the Hokchi Cross Assignment and Premier's option exercise, we will own a 25% PI in each of Block 2 and Block 31, and Hokchi will be the operator of both blocks.

  In February 2019, the CHN granted approval for drilling in the Acan-1 exploration well in Block 2. Operations are expected to begin in March 2019 and extend into the second quarter. Soon thereafter, we plan to participate in two prospects in Block 31. Beyond the Acan prospects, we believe that Blocks 2 and 31 contain a significant portfolio of compelling prospects with strong technical ties to offsetting discoveries.

Recent Developments

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.

HP-I Dry-Dock Downtime

During the first quarter of 2019, the HP-I entered into its regulatory required dry-dock period. Regulators require the ship to go to dry-dock twice every five years. On May 7, 2019, the HP-I completed its dry-dock requirement and departed the shipyard. After a period of sea trials, we expect production from the Phoenix Field to commence in late March 2019. The annualized production impact of the shut-in in the Phoenix Field is estimated to be between 2.0 MBoepd and 3.0 MBoepd.

Drilling and Exploration Activities

The Tornado 3 well's drilling operations completed in December 2018 and completed in January 2019. We expect production to commence by early second quarter, 2019, with an expected net production rate between 10.0 MBoepd and 15.0 MBoepd. We are the operator and own a 65% working interest.

The Boris 3 wells started drilling operations in January 2019 and completed in February 2019. We expect production to commence in the second quarter of 2019, with a net production between or 2.8 Mboepd and 4.6 MBoepd. We are the operator and own a 100% working interest.

Summary of Reserves

Our estimated proved reserves totaled 151.7 MMBoe at December 31, 2018. The following table summarizes our estimated proved reserves as of December 31, 2018, 2017 and 2016 which are all located in the United States.

	Summary of Proved Reserves						
	Oil (MBbls)	Natural Gas (MMcf)	NGL (MBbls)	Mboe	Percent of Total Proved	Standardized Measure (in thousands)	PV-10 (in thousands)
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	76%		3,191,155
Proved Undeveloped	27,009	39,660	2,592	36,211	24%		734,108
Total Proved	112,539	171,024	10,696	151,739		$ 3,340,246	$3,925,263
December 31, 2017[1]							
Proved Developed Producing	23,656	37,161	1,930	31,780			$ 776,786
Proved Developed Non-Producing	13,804	40,416	1,385	21,924			270,363
Total Proved Developed	37,460	77,577	3,315	53,704	53%		1,047,149
Proved Undeveloped	35,344	50,079	3,232	46,921	47%		760,520
Total Proved	72,804	127,656	6,547	100,625		$ 1,807,669	$1,807,669
December 31, 2016[1]							
Proved Developed Producing	28,757	52,062	2,277	39,711			$ 707,315
Proved Developed Non-Producing	16,996	44,060	1,754	26,094			242,877
Total Proved Developed	45,753	96,122	4,031	65,805	63%		950,192
Proved Undeveloped	26,613	54,482	2,205	37,897	37%		385,843
Total Proved	72,366	150,604	6,236	103,702		$ 1,336,035	$1,336,035

(1) Does not include reserves acquired in the Stone Combination, which closed in May 10, 2018.

Reconciliation of PV-10 to Standardized Measure

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, 2018, 2017, and 2016.

	December 31, 2018	December 31, 2017[1]	December 31, 2016[1]
Standardized measure	$ 3,340,246	$ 1,807,669	$ 1,336,035
Present value of future income taxes discounted at 10%	585,017	—	—
PV-10	$ 3,925,263	$ 1,807,669	$ 1,336,035

(1) For the tax years ended December 31, 2017 and 2016, we were not a taxpaying entity for federal income tax purposes, we were not subject to federal or state income taxes and thus made no provision for federal or state income taxes in the calculation of our standardized measure.

Changes in Proved Developed Reserves

Our proved developed reserves as of December 31, 2018 increased by 61.8 MMBoe to 115.5 MMBoe from 53.7 MMBoe at December 31, 2017, a 115% increase. This increase was due to:

- acquisitions of 58.0 MMBoe from the Stone Combination and 3.5 MMBoe from the Whistler Acquisition, for more information, see Part II, Item 8. Financial Statements and Supplementary Data — Note 3 — *Acquisitions*;
- Positive revisions of 4.5 MMboe;
- Proved undeveloped reserves ("PUD") conversions of 10.0 MMBoe
- extensions and discoveries of 2.5 MMBoe primarily attributable to wells drilled in Ewing Bank Block 305 (1.3 MMBoe) and Ship Shoal Block 224 (0.5 MMBoe); and offset by
- production of 16.7 MMBoe

Development of Proved Undeveloped Reserves

The following table discloses our estimated PUD reserve activities during the year ended December 31, 2018:

	Oil, Natural Gas and NGLs	**Future Development Costs**
	(MBoe)	(in thousands)
Proved undeveloped reserves at December 31, 2017	46,921	$ 447,721
Changes during the year:		
Extensions and discoveries	3,108	27,000
Revisions of previous estimates	(4,515)	(3,996)
Acquired	654	8,367
Conversion to Proved Developed Producing reserves	(9,957)	(82,426)
Total proved undeveloped reserves changes	(10,710)	(51,055)
Proved undeveloped reserves at December 31, 2018	36,211	$ 396,666

Our PUD reserves at December 31, 2018 decreased by 10.7 MMBoe, or 23% primarily due to:

*Extensions and Discoveries***.** We added 3.1 MMBoe of PUD reserves through an evaluation of Green Canyon Block 18 which was initially acquired in the Whistler Acquisition. See Part II, Item 8. Financial Statements and Supplementary Data — Note 3 — *Acquisitions*, for more information.

Revisions of Previous Estimates. Downward reserves revisions of 4.5 MMBoe primarily due to timing of development of certain PUD locations to move beyond 5 years of 3.3 MMBoe and downward revisions of 1.2 MMBoe. The revisions were caused by a new geological data and changes in overall project economics, and expiration of a block. Future development costs related to the PUD revisions decreased by $4.0 million primarily due to a review of completion strategy and optimization of capital expenditures in the Phoenix Field.

Acquired. We added a 0.7 MMBoe PUD reserves in Bayou Hebert Field through the Stone Combination.

Conversion to Proved Developed Producing. 2017 PUD to proved developed conversions of 10.0 MMBoe are primarily attributable to the Phoenix Field, Tornado #3ST and two wells in Main Pass Block 74, A8ST and A11ST.

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, 2018 totaled approximately $396.7 million, primarily attributable the Phoenix Field's $317.3 million future development costs. 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 Bank Credit Facility, in each future annual period prior to the five year expiration. Our 2019 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, 2018, 2017 and 2016, 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 reserve quantities, reserves categorization, future producing rates, future net revenue and the present value of such future net revenue to 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, 2018, 2017 and 2016. Our management requires that the independent petroleum engineers and geologist's 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 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, 2018, 2017 and 2016 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 this 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

Floyd Bone, 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. Mr. Bone has over 44 years of industry experience with positions of increasing responsibility, including 36 years as a reserves evaluator or manager. Mr. Bone's further professional qualifications include a State of Texas Professional Engineering License, extensive internal and external reserve training and asset evaluation. In addition, Mr. Bone is an active participant in industry reserve seminars and professional industry groups, and has been a member of the SPEE for over 44 years. Mr. Bone reports directly to our Vice President of Corporate Development.

Drilling Activity

The following table sets forth our drilling activity:

	Exploratory and Appraisal Wells[1]						Development Wells[1]						Total	
	Productive[2]		Dry[3]		Total		Productive[2]		Dry[3]		Total			
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
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
December 31, 2017														
United States	4.0	3.7	—	—	4.0	3.7	—	—	—	—	—	—	4.0	3.7
Mexico	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	4.0	3.7	—	—	4.0	3.7	—	—	—	—	—	—	4.0	3.7
December 31, 2016														
United States	1.0	0.7	—	—	1.0	0.7	—	—	—	—	—	—	1.0	0.7
Mexico	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	1.0	0.7	—	—	1.0	0.7	—	—	—	—	—	—	1.0	0.7

(1) As of December 31, 2018, two exploratory and appraisal wells have been excluded from the table until a determination is made if the wells have found proved reserves. Also excluded from the table are two development wells awaiting completion. These wells are shown as "Wells Suspended or Waiting on Completion" in the table below.

(2) 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.

(3) 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 well, as opposed to the year the well was drilled.

As of December 31, 2018, 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	—	—	2.0	1.7	—	—	—	—
Mexico	1.0	0.4	—	—	1.0	0.4	—	—
Total	1.0	0.4	2.0	1.7	1.0	0.4	—	—

Productive Wells

The number of our productive wells is as follows:

	December 31, 2018	
	Gross	Net
Crude oil	201.0	178.3
Natural gas	70.0	50.6
Total [(1)]	271.0	228.9

(1) 3 gross wells have dual completions.

Acreage

Gross and net developed and undeveloped acreage is as follows:

	December 31, 2018					
	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
United States						
Deepwater	168,714	131,360	252,895	161,895	421,609	293,255
Shelf	308,476	211,244	155,803	120,392	464,279	331,636
Total United States	477,190	342,604	408,698	282,287	885,888	624,891
Mexico	—	—	162,904	49,809	162,904	49,809
Total	477,190	342,604	571,602	332,096	1,048,792	674,700

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, 2018 are scheduled to expire as shown in the table below (the terms of which may be extended by drilling and production operations):

	Undeveloped Acreage	
	Gross	Net
2019[(1)]	234,199	98,424
2020	33,280	25,556
2021	24,200	14,984
2022	50,439	34,008
2023 and beyond	229,484	159,124
Total	571,602	332,096

(1) The 2019 undeveloped acreage includes 162,904 gross and 49,809 net acres of Block 2 and 7 from Mexico's PSCs for Round 1. The PSCs allows us to file for a 2 year extension.

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,		
	2018	2017	2016
Production Volumes:			
Crude oil (MBbls)	11,771	7,048	5,126
Natural gas (MMcf)	22,771	16,308	19,001
NGLs (MBbls)	1,176	706	603
Total (MBoe)	16,742	10,472	8,896
Percent of Boe from crude oil	70%	67%	58%
Average Sales Price (including commodity derivatives):			
Crude oil (MBbls)	$ 57.12	$ 52.46	$ 68.46
Natural gas (MMcf)	$ 3.16	$ 2.93	$ 3.24
NGLs (MBbls)	$ 30.50	$ 23.59	$ 15.81
Average (MBoe)	$ 46.60	$ 41.46	$ 47.44
Average Sales Price (excluding commodity derivatives):			
Crude oil (MBbls)	$ 66.42	$ 48.92	$ 38.55
Natural gas (MMcf)	$ 3.23	$ 3.00	$ 2.25
NGLs (MBbls)	$ 30.50	$ 23.59	$ 15.81
Average (MBoe)	$ 53.24	$ 39.18	$ 28.08
Average Direct LOE and Workover per Boe (1)	$ 12.60	$ 13.56	$ 16.77

(1) Includes oil and natural gas operating costs and major maintenance expense and excludes production taxes.

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

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, 2018, 2017 and 2016:

	Year Ended December 31,		
	2018	2017	2016
Production Volumes:			
Crude oil (MBbls)	5,160	4,657	2,600
Natural gas (MMcf)	5,311	5,203	3,235
NGLs (MBbls)	491	520	312
Average (MBoe)	6,536	6,044	3,451
Percent of Boe from crude oil	79%	77%	75%
Average Sales Price (excluding commodity derivatives):			
Crude oil (MBbls)	$ 65.11	$ 48.75	$ 37.88
Natural gas (MMcf)	$ 3.57	$ 3.48	$ 2.84
NGLs (MBbls)	$ 29.04	$ 24.49	$ 18.97
Average (MBoe)	$ 56.48	$ 42.66	$ 32.92
Average Direct LOE and Workover per Boe (1)(2)	$ 4.17	$ 4.27	$ 12.30

(1) In response to the Tornado II's production commencement during the fourth quarter of 2016, we entered into a new production handling agreement ("PHA") with certain working interest partners. The fees from this PHA were recorded as a reduction to lease operating expense beginning in 2017.

(2) Includes oil and natural gas operating costs and major maintenance expense and excludes production taxes.

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, 2018. The information below includes the period form the Closing Date of the Stone Combination, May 10, 2018, through December 31, 2018.

		Year Ended December 31, 2018
Production Volumes:		
Crude oil (MBbls)		2,042
Natural gas (MMcf)		1,758
NGLs (MBbls)		151
Total (MBoe)		2,486
Percent of Boe from crude oil		82%
Average Sales Price (excluding commodity derivatives):		
Crude oil (MBbls)	$	69.06
Natural gas (MMcf)	$	3.50
NGLs (MBbls)	$	30.95
Average (MBoe)	$	61.08
Average Direct LOE and Workover per Boe (1)(2)	$	1.60

(1) The Pompano Field has PHAs with certain working interest partners. The PHAs are recorded as a reduction to lease operating expense.

(2) Includes oil and natural gas operating costs and major maintenance expense and excludes production taxes.

Expenditures and Costs Incurred

For information on property development, exploration and acquisition costs, see Part II, Item 8. Financial Statements and Supplementary Data — Note 14 — *Supplemental Oil and Gas Disclosures*.

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 royalty, overriding royalty, 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, 2018, 65% and 18% of our oil, natural gas and NGL revenues were attributable to Shell Trading (US) Company and Phillips 66, 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 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 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 Gulf of Mexico windstorm; however, such coverage is subject to a maximum of $155 million per named windstorm and in the aggregate, and is also subject to a maximum of $25 million per occurrence retention. We separately maintain an operators extra expense policy with additional coverage for an amount up to $500 million for Gulf of Mexico deepwater drilling wells, $150 million for Gulf of Mexico shelf drilling wells, $75 million for Gulf of Mexico producing and shut-in wells, $50 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 regulations. An overview of these regulations is set forth below. We do not believe that compliance with existing requirements will have 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 rules 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 P&A obligations;
- plugging and abandoning of wells; and
- transportation of production.

Outer Continental Shelf ("OCS") Regulation. Our operations on federal oil and natural gas leases in the Gulf of Mexico are subject to regulation by the Bureau of Safety and Environmental Enforcement ("BSEE") and the Bureau of Ocean Energy Management ("BOEM"), both agencies of the U.S. Department of the Interior ("DOI). These leases 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"). These laws and regulations are subject to change, and many new requirements, including those related to safety, permitting and performance, were imposed by BSEE and BOEM subsequent to the 2010 Deepwater Horizon incident. For offshore operations, lessees must obtain BOEM approval for exploration, development and production plans prior to the commencement of such operations. In addition to permits required from other agencies such as the U.S Environmental Protection Agency (the "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.

These rules are frequently subject to change. For example, in 2016, BSEE published a final rule on well control that, among other things, imposes 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. Pursuant to President Trump's Executive Orders dated March 28, 2017, and April 28, 2017 (the "Executive Orders"), BSEE initiated a review of the well control regulations to determine whether the rules are consistent with the stated policy of encouraging energy exploration and production, while ensuring that any such activity is safe and environmentally responsible. In October 2017, BSEE announced, in a report published by the DOI, that it is considering several revisions to the regulations and that it is in the process of determining the most effective way to engage stakeholders in the process. In another example, the BSEE published a final rule in September 2018 amending its production safety systems regulations, which includes the imposition of operational and design standards and the removal of the requirement of offshore operators to certify through an independent third party that their critical safety and pollution prevention equipment (e.g. subsea safety equipment, including blowout preventers) is operation and functioning as designed in the most extreme conditions.

In a third example, BOEM published a proposed rule in April 2016 that would update existing air emissions requirements relating to offshore oil and natural gas activity on the OCS. BOEM regulates these air emissions in connection with its review of exploration and development plans, rights of way ("ROWs") and rights of use ("RUEs") applications. The proposed rule would bolster existing air emissions requirements by, among other things, requiring the reporting and tracking of the emissions of all pollutants defined by the EPA to affect human health and public welfare. Pursuant to the Executive Orders, BOEM is reviewing the proposed air quality rule. In October 2017, the DOI announced that it is currently reviewing recommendations on how to proceed, including promulgating final rules for certain necessary provisions and issuing a new proposed rule that may withdraw certain provisions and seek additional input on others.

Compliance with new and future regulations 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. 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, BOEM and 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 BOEM and 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, 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. For example, in the Notice to Lessees and operators ("NTL") #2016-N01 (the "2016 NTL"), BOEM announced updated financial assurance and risk management requirements for offshore leases. The 2016 NTL details procedures to determine a lessee's ability to carry out its lease obligations—primarily the decommissioning of facilities—and whether to require lessees to furnish additional financial assurance to meet BOEM's estimate of the lessees decommissioning obligations. The 2016 NTL supersedes the agency's prior practice of allowing operators of a certain net worth to waive the need for supplemental bonds and provides updated criteria for determining a lessee's ability to self-insure only a small portion of its OCS liabilities based upon the lessee's financial capacity and financial strength. The 2016 NTL also allows lessees to meet their additional financial security requirements pursuant to an individually approved tailored plan, whereby an operator and BOEM agree to set a timeframe for the posting of additional financial assurances. The 2016 NTL became effective in September 2016, but the BOEM has since extended indefinitely beyond June 30, 2017 the start date for implementation of this NTL, except for certain circumstances where there is a substantial risk of nonperformance of the interest holder's decommissioning liabilities, so as to provide BOEM with time to review its complex financial assurance program.

In late 2016, we received orders from BOEM to provide additional financial assurance in material amounts relating to our OCS properties (the "BOEM 2016 Orders"). We entered into discussions with 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, the BOEM has indefinitely delayed beyond June 30, 2017 implementation of the 2016 NTL, has rescinded the BOEM 2016 Orders while BOEM reviews its financial assurance program and, to date, has taken no action with respect to our previously submitted proposed tailored plan.

We remain in active discussions with our government regulators and our industry peers with regard to any future rule making and financial assurance requirements. The BOEM is continuing to review and reconsider its financial assurance program and thus the amounts of any financial assurance that may be demanded by the agency is uncertain at this time. Notwithstanding the 2016 NTL, BOEM may also bolster its financial assurance requirements mandated by rule for all companies operating in federal waters. The BOEM could also make new demands for additional financial assurance in material amounts in the event the agency chooses to implement the 2016 NTL. Such demands could exceed our ability to provide any additional financial assurance that may be required by BOEM in the future. The future cost of compliance with our existing supplemental bonding requirements, including the obligations imposed upon us as a result of the 2016 NTL, to the extent implemented, as well as any other future BOEM directives, or any other changes to BOEM's rules applicable to our or our subsidiaries' properties, could materially and adversely affect our financial condition, cash flows, and results of operations.

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.

Environmental 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; 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. 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. 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, 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 ("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 ("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. In addition, in January 2018, BOEM raised OPA's damages liability cap to $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 for companies operating on the OCS, although BOEM may increase this amount in certain situations. From time to time, the United States Congress has proposed 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 ("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. 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 ("ESA") restricts activities that may affect federally identified endangered and threatened species or their habitats. Additionally, the Migratory Bird Treaty Act ("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 Marine Mammal Protection Act similarly prohibits the taking of marine mammals without authorization. We conduct operations on oil and natural gas leases in areas where certain species that are protected by the ESA, MBTA and Marine Mammal Protection Act are known to exist and where other species that potentially could be protected under these statutes. The U.S. Fish and Wildlife Service 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 ("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, pursuant to a consent decree issued by the U.S. District Court for the District of Columbia in 2016, the EPA is required to propose no later than March 15, 2019, a rulemaking for revision of certain Subtitle D criteria regulations that could result in oil and natural gas exploration and production wastes being regulated as hazardous wastes, or sign a determination that revision of the regulations is unnecessary. If EPA proposes rulemaking for revised oil and gas regulations, the consent decree requires that the EPA take final action following notice and comment rulemaking no later than July 15, 2021. A 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. Comprehensive Environmental Response, Compensation and Liability Act ("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 ("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 October 2015, the EPA lowered the National Ambient Air Quality Standard ("NAAQS") for ozone from 75 to 70 parts per billion. 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 ("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. From time to time, the United States Congress has considered a variety of tax, energy-related or environmental market-based mechanisms to promote or induce the reduction of emissions of Green House Gasses ("GHG"s) by several commercial or industrial sectors. In addition, more than one half of the states already have begun implementing legal measures such as renewable energy requirements or cap and trade programs to reduce emissions of GHGs.

Additionally, the United States is one of almost 200 nations that, in December 2015, agreed to the Paris Agreement, an international climate change agreement in Paris, France that calls for countries to set their own GHG emissions targets and be transparent about the measures each country will use to achieve its GHG emissions targets. The Paris Agreement entered into force on November 4, 2016. In June 2017, President Trump stated that the United States would withdraw from the Paris Agreement, but may enter into a future international agreement related to GHGs. The Paris Agreement provides for a four-year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States' adherence to the exit process is uncertain and/or the terms on which the United States may reenter the Paris Agreement or a separately negotiated agreement are unclear at this time.

In addition, the EPA has determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment because emissions of such gases contribute to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA began adopting and implementing regulations to restrict emissions of GHGs under existing provisions of the federal CAA. The EPA has adopted rules regulating GHG emissions under the existing CAA, including a rule regulating emissions of GHGs from certain large stationary sources through preconstruction and operating permit requirements. The EPA has also adopted rules requiring the reporting of GHG emissions from specified large GHG emission sources in the United States, on an annual basis. Currently, our operations include one active floating production unit (the HP-I,) and our facilities at the Ram Powell and Pompano Fields are subject to those EPA GHG reporting requirements.

The EPA has also taken steps to limit methane emissions, a GHG, from certain new modified or reconstructed facilities in the oil and natural gas sector through the adoption of a final rule in June 2016 establishing Subpart OOOOa standards for methane emissions. However, in 2017, the EPA published a proposed rule to stay certain portions of these Subpart OOOOa standards for two years but the rule was not finalized. Rather, in February 2018, the EPA finalized amendments to certain requirements of the June 2016 final rule, and in September 2018 the EPA proposed additional amendments, including rescission of certain requirements and revisions to other requirements, such as fugitive emission monitoring frequency. In the event that the EPA's June 2016 rule should remain or be placed in effect, or should any other new methane emission standards be imposed on the oil and natural gas sector, such requirements could result in increased costs to our operations as well as result in restrictions, delays or cancellations in such operations, which costs, restrictions, delays or cancellations could adversely affect our business.

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 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.

Under the PSCs, we are jointly and severally liable, along with Sierra and Premier, 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 recession 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"), the 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 $1,269,500 per violation, per day for 2019 (this amount is adjusted annually for inflation). The 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 the FERC will take. Therefore, there is no assurance that the current regulatory approach recently pursued by the 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

The 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 the 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. The 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. The FERC reviews the index formula every five years. Effective July 1, 2016, the annual index adjustment for the five-year period ending June 30, 2021, will equal the producer price index for finished goods for the applicable year plus an adjustment factor of 1.23%. 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. On March 15, 2018, FERC issued a Revised Policy Statement on Treatment of Income Taxes ("Revised Policy Statement") stating, among other things, that with respect to oil and refined products pipelines subject to FERC jurisdiction, the impacts of the Revised Policy Statement and the Tax Cuts and Jobs Act of 2017 on the costs of FERC-regulated oil and NGL pipelines will be reflected in FERC's next five-year review of the oil pipeline index, which will generate the index level to be effective July 1, 2021. FERC's establishment of a just and reasonable rate, including the determination of the appropriate oil pipeline index, is based on many components, and tax-related changes will affect two such components, the allowance for income taxes and the amount for accumulated deferred income taxes, while other pipeline costs also will continue to affect FERC's determination of the appropriate pipeline index. Accordingly, depending on FERC's application of its indexing rate methodology for the next five-year term of index rates, the Revised Policy Statement and tax effects related to the Tax Cuts and Jobs Act of 2017 may impact our revenues associated with any transportation services we may provide pursuant to cost-of-service based rates in the future, including indexed rates.

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. FERC issued an Advance Notice of Proposed Rulemaking on October 20, 2016, that addressed issues related to FERC's indexing methodology and liquids pipeline reporting practices. If implemented, the proposals in this rulemaking could affect the profitability of certain liquids pipelines.

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 the 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.

The 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.

Employees

We had 374 employees as of March 6, 2019.

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 on Form 10-K, 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.

Oil and natural gas prices are volatile. Significant declines in commodity prices in the future 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. Oil and natural gas prices significantly declined in the second half of 2014, with sustained lower prices continuing throughout 2015, 2016 and 2017. Despite a modest recovery from late 2017 to mid-2018, commodity prices could remain suppressed or decline further in the future, which will likely have material adverse effects on our proved reserves and borrowing base. 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 produce economically. A reduction in 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. 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, 2016 through December 31, 2018, the NYMEX WTI crude oil price per Bbl ranged from a low of $30.62 to a high of $70.76, and the NYMEX natural gas price per MMBtu ranged from a low of $1.71 to a high of $4.72. The high, low and average prices for NYMEX WTI and NYMEX Henry Hub are monthly contract prices. 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;
- domestic and foreign governmental 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;
- actions by the Organization of Petroleum Exporting Countries 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;
- 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 74%, 19%, and 7%, respectively, of our estimated proved reserves as of December 31, 2018, and approximately 70%, 23%, and 7%, respectively, of our 2018 production on an MBoe basis, our financial results are sensitive to movements in oil, natural gas, and NGL prices.

We are required to meet a minimum work program expressed in work units during a four-year exploration period according to our PSCs with the CNH.

On September 11, 2018, we entered into a transaction with Hokchi, a subsidiary of PAE, to cross assign 25% PIs in Block 2 and Block 31, both in the Sureste Basin off the coast of Mexico. Our assignment of a 25% PI in Block 2 to Hokchi closed on December 21, 2018, and Hokchi has assumed operator responsibilities with respect to Block 2. Hokchi's assignment of Block 31 to us will be completed upon final approval by the CNH. In addition, Premier exercised its option to reduce its PI in Block 2 to zero and assign a 5% PI to each of Sierra and us. Such assignment is also subject to CNH's approval. Upon the completion of the Hokchi Cross Assignment and Premier's option exercise, Hockchi will be the operator of both blocks, we will own a 25% PI in Block 31 and our PI in Block 2, and our pro rata portion of the minimum work program on Block 2 will decrease from 45% to 25%. We posted an additional \$8.7 million required in letters of credit to cover our pro rata portion of the minimum work program on Block 31 pursuant to the relevant PSC.

If we or the Consortium is unable to meet a minimum work program, we could be liable along with the other members in the Consortium for the remaining financial guarantee, and the CNH could rescind the PSC for a default.

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% 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% Senior Secured Notes, 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% Senior Secured 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.

Regulatory requirements and permitting procedures imposed by the BOEM and the BSEE could significantly delay our ability to obtain permits to drill new wells in offshore waters.

BSEE and BOEM have imposed new and more stringent permitting procedures and regulatory safety and performance requirements for new wells to be drilled in federal waters. Compliance with these added and more stringent regulatory requirements and with 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 and possible additional regulatory initiatives could result in difficult and more costly actions and adversely affect or delay new drilling and ongoing development efforts. Moreover, these governmental agencies are continuing to evaluate aspects of safety and operational performance in the Gulf of Mexico and, as a result, are continuing to develop and implement new, more restrictive requirements. For example, in April 2016, BSEE published a final rule on well control that, among other things, imposes 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. Pursuant to the Executive Orders, BSEE initiated a review of the well control regulations to determine whether the rules are consistent with the stated policy of encouraging energy exploration and production, while ensuring that any such activity is safe and environmentally responsible. One consequence of this review is that in September 2018, BSEE published final revisions to its regulations regarding offshore drilling safety equipment, which includes the removal of the requirement for offshore operators to certify through an independent third party that their critical safety and pollution prevention equipment (*e.g.*, subsea safety equipment, including blowout preventers) is operational and functioning as designed in the most extreme conditions.

Also, in April 2016, BOEM published a proposed rule that would update existing air emissions requirements relating to offshore oil and natural gas activity on the OCS. BOEM regulates these air emissions in connection with its review of exploration and development plans, rights of way and rights of use, and/or easement applications. The proposed rule would bolster existing air emissions requirements by, among other things, requiring the reporting and tracking of the emissions of all pollutants defined by the EPA to affect human health and public welfare. Pursuant to the Executive Orders, BOEM has ceased rulemaking activities for and is reviewing the proposed air quality rule. In October 2017, the DOI announced that it is currently reviewing recommendations on how to proceed, including promulgating final rules for certain necessary provisions and issuing a new proposed rule that may withdraw certain provisions and seek additional input on others.

Compliance with new and future regulations could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business. Furthermore, among other adverse impacts, to the extent that BOEM and BSEE do not reduce the stringency of existing oil and gas safety and performance-related regulations and other regulatory initiatives, the regulatory requirements imposed by such existing or future, more stringent regulations or other regulatory initiatives could delay operations, disrupt our operations, or increase the risk of leases expiring before exploration and development efforts have been completed due to the time required to develop new technology. Additionally, if left unchanged, the existing, or future, more stringent oil and gas safety and performance-related regulations and other regulatory initiatives imposed by BOEM and BSEE could result in incurrence of associated added costs, limit operational activities in certain areas, or cause us to incur penalties or shut-in production at one or more of our facilities. 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.

New guidelines issued by BOEM related to financial assurance requirements to cover decommissioning obligations for operations on the OCS may have a material adverse effect on our business, financial condition, or results of operations.

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. In July 2016, BOEM 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 or RUEs. The 2016 NTL became effective in September 2016, but BOEM has since extended indefinitely beyond June 30, 2017 the start date for implementing this NTL, except in certain circumstances where there is a substantial risk of nonperformance of the interest holder's decommissioning liabilities, so as to provide BOEM with time to review its complex financial assurance program.

In late 2016, we received orders from BOEM to provide additional financial assurance in material amounts relating to our OCS properties (the "BOEM 2016 Orders"). We entered into discussions with 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, BOEM has indefinitely delayed beyond June 30, 2017 implementation of the 2016 NTL, has rescinded the BOEM 2016 Orders while BOEM reviews its financial assurance program and, to date, has taken no action with respect to our previously submitted proposed tailored plan.

As of the filing date of this Annual Report on Form 10-K, we have no outstanding BOEM orders for financial assurance obligations, although we are in discussions with the agency regarding providing financial assurance in what we view as the normal course of business for one well, Mount Providence, that was completed July 2018. Following completion of its review of its financial assurance program, BOEM may elect to retain the 2016 NTL in its current form or may make revisions thereto. Thus, until the review is completed and BOEM determines what additional financial assurance may be required by us, we cannot provide any assurance of the amount of any additional financial assurance, which may be material, that may be ordered by BOEM and required in any proposed tailored plan that we may submit to BOEM in the future for approval, or that such additional financial assurance amounts can be obtained. Moreover, BOEM could in the future make new demands for additional financial assurances in material amounts relating to the decommissioning of our OCS properties. 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 BOEM to provide additional surety bonds or other financial assurances, 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 fully implemented, the 2016 NTL is likely to result in 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 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 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.

We have a subsidiary that is subject to a plea agreement with the Department of Justice ("DOJ") pursuant to which certain exploration and production activities must comply with a Safety and Environmental Compliance Program ("SECP"). Noncompliance with the SECP could result in a violation of the plea agreement and provide a basis for revocation or modification of probation.

In February 2014, we received a grand jury subpoena from the DOJ addressing activities that occurred on the Ship Shoal 225A production platform operated by one of our subsidiaries, ERT. On November 30, 2015, ERT was charged with two violations of the OCSLA in connection with hot work and blowout preventer testing activities, and with two violations of the CWA for self-reported activities surrounding overboard discharge sampling and unpermitted discharges. On January 6, 2016, ERT pled guilty to these charges. On April 6, 2016, the United States District Court for the Eastern District of Louisiana (the "Court") accepted ERT's plea and sentenced ERT, consistent with the plea agreement, to pay a penalty of $4.2 million, which ERT has paid. The Court placed ERT on probation for three years. The conditions of probation include compliance with an agreed SECP, pursuant to which ERT and another subsidiary of ours must implement enhanced safety and environmental compliance inspections, reviews and audits, implement a comprehensive training program, implement enhanced operational controls to better manage, detect and prevent safety and environmental violations, and preparation and implementation of a schedule for decommissioning. Any failure to comply with the SECP could result in a violation of the plea agreement and provide a basis for revocation or modification of probation, which could adversely our financial condition and operations.

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, 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. In addition, we may face limitations on our ability to access the debt and equity capital markets and complete asset sales, an increased counterparty credit risk on our derivatives contracts, and the requirement by our contractual counterparties to post collateral guaranteeing performance.

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 significantly limited since the significant decline in commodity prices as compared to mid-2014. Access to the equity and high yield debt markets continue to be limited.

We are a holding company that has no material assets other than our ownership of the equity interests of Talos Production. Accordingly, we are dependent upon distributions from Talos Production 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. We have no independent means of generating revenue. To the extent Talos Production has available cash, we will cause Talos Production 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 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 is limited in its ability to make distributions to us, including the significant restrictions the agreements governing Talos Production’s debt impose on the ability of Talos Production to make distributions and other payments to us. To the extent that we need funds and Talos Production 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 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 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 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, 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; and/or
- changes in the regulatory environment such as the guidelines issued by BOEM related to financial assurance requirements to cover decommissioning obligations for operations on the OCS.

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.

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

Our production is primarily associated with our properties in the 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 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.

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, 2018, approximately 39% and 15% of our historical production and 41% and 17% of our historical 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 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. As of the filing date of this Annual Report on Form 10-K, Helix has dry-docked the HP-I, and the shut-in is estimated to through March 2019. On September 10, 2016, the HP-I was disconnected from the production buoy and released for dry dock for 28 days. Upon completion of the dry dock, the HP-I remained disconnected from the buoy connecting it to the Phoenix Field due to Federal Emergency Management Agency testing of test upgrades to the power management system, preventing us from reconnecting the HP-I to the Phoenix Field for a further five days. Once the buoy was connected, Phoenix Field production remained shut-in for an additional five days to conduct buoy remediation of the swivel piping. In addition, for 25 days in March 2015, we were required to disconnect the HP-I from the production buoy due to upgrades to the power management system of the vessel, which is an integral part of the dynamic positioning system. The upgrade work was followed by sea trials that tested the dynamic positioning system and were required by various regulatory groups, including the United States Coast Guard.

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 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.

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 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 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.

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 gas properties. Under the full cost method of accounting, we compare, at the end of each financial reporting period for each cost center, the present value of estimated future net cash flows from proved reserves (based on a trailing 12-month average, hedge-adjusted commodity price and excluding cash flows related to estimated abandonment costs), to the net capitalized costs of proved oil and gas properties, net of related deferred taxes. We refer to this comparison as a ceiling test. If the net capitalized costs of proved oil and gas properties exceed the estimated discounted future net cash flows from proved reserves, we are required to write down the value of our oil and gas properties to the value of the estimated discounted future net cash flows. A write-down of oil and 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 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.

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 and 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 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 addition, the OPA requires operators of U.S. offshore facilities to prove that they have the financial capability to respond to costs that may be incurred in connection with potential oil spills. Under the OPA and other environmental statutes such as the CERCLA, the RCRA and analogous state laws, owners and operators of certain defined onshore and offshore facilities are strictly liable for spills of oil and other regulated substances, subject to certain limitations. Consequently, a spill from one of our facilities subject to laws such as the OPA, CERCLA and RCRA could require the expenditure of additional, and potentially significant, amounts of capital, or could have a material adverse effect on our earnings, results of operations, competitive position or financial condition. We cannot predict the ultimate cost of compliance with these requirements or their impact on our earnings, operations or competitive position.

In September 2015, we, together with the Consortium 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. The work units represent the performance of exploration studies and seismic and drilling activities. The aggregate value of the minimum work program under the PSCs is approximately $143.0 million (gross), of which we are responsible for a pro rata portion based on our PI. In order to guarantee the execution of the minimum work program under the PSCs, the Consortium was required to post a financial guarantee to the CNH of approximately $143.0 million (gross), of which our share was $48.7 million. We satisfied our share through a performance bond. As the Consortium completes the minimum work program under the PSCs, the amount of the financial guarantee will be reduced accordingly beginning after the second anniversary of entering into the PSCs. Effective January 23, 2018, the activities already performed on Block 7 have satisfied the minimum work program on Block 7, reducing the $143.0 million (gross) in outstanding letters of credit by $65.7 million (gross). Activities on Block 2 are in the planning phase and we are on schedule to satisfy the minimum work program on Block 2 by September 4, 2019.

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.

Under the PSCs, we are also jointly and severally liable, along with Sierra, Premier and Hokchi, 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.

Production periods or reserve lives for 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 Gulf of Mexico. As a result, our reserve replacement needs from new prospects may be greater than those of other oil and 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 they have lowered 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, 2018 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 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 gas industry in general.

At December 31, 2018, approximately 24% of our estimated proved reserves (by volume) were undeveloped and approximately 25% 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 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.

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.

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 acreage has to be drilled before lease expiration 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 sections.

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 changed 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.

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 Gulf of Mexico deepwater and/or in the Gulf Coast deep gas, our drilling activities increases 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 Gulf of Mexico. Exploration for oil or natural gas in the deepwater of the Gulf of Mexico generally involves greater operational and financial risks than exploration on the 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 on the 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.

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.

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 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 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.

Moreover, the timing for pursuing restoration and removal activities has accelerated for operators in the U.S Gulf of Mexico following BSEE's issuance of an NTL that established a more stringent regimen for the timely decommissioning of what is known as "idle iron" wells, which are wells, platforms and pipelines that are no longer producing or serving exploration or support functions with respect to an operator's lease in the Gulf of Mexico. The idle iron NTL, which was initially issued in 2010 and re-issued with a more streamline framework in December 2018, requires decommissioning of any well that has not been used during the past five years for exploration or production on active leases and is no longer capable of producing in paying quantities, which must then be permanently plugged or temporarily abandoned within three years' time. Similarly, platforms or other facilities no longer useful for operations must be removed within five years of the cessation of operations. We may have to draw on funds from other sources to satisfy decommissioning costs. The use of other funds to satisfy such decommissioning costs could have a material adverse effect on our financial position and results of operations. Moreover, as a result of the implementation of the idle iron NTL, there is expected to be increased demand for salvage contractors and equipment operating in the Gulf of Mexico, resulting in increased estimates of plugging, abandonment and removal costs and associated increases in operators' asset retirement obligations.

In addition, we could become responsible for decommissioning liabilities related to offshore facilities we no longer own or operate. Under existing BOEM rules relating to assignment of offshore leases and other legal interests on the OCS, assignors of such interest may be held jointly and severally liable, regardless of any indemnity agreements, for decommissioning of OCS facilities existing at the time the assignment was approved by the BOEM in the event that the assignee, or any subsequent assignee, is unable or unwilling to conduct required decommissioning obligations. The costs of performance of required decommissioning obligations, whether our or any assignees, may be material. Moreover, several onshore and offshore exploration and production companies have sought bankruptcy protection over the past several years. The government may seek to impose a bankrupt entity's P&A obligations on us or other predecessors-in-interest, which could be significant and have a material adverse effect on our business, results of operations, financial condition and cash flows.

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 the nonpayment and nonperformance by customers. We are unable to predict what impact the financial difficulties of certain purchasers may have on our future results of operations and liquidity.

The market price of our common stock may decline as a result of the Stone Combination.

The market price of our common stock may decline as a result of the Stone Combination if, among other things, we are unable to achieve the expected benefits of the transaction, or if the transaction costs related to the Stone Combination and integration are greater than expected. The market price also may decline if we do not achieve the perceived benefits of the Stone Combination as rapidly or to the extent anticipated by financial or industry analysts or if the effect of the Stone Combination on our financial results is not consistent with the expectations of financial or industry analysts.

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 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.

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 other partners: Sierra, Premier and Hokchi. 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 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.

Our operations may be exposed to risks of illegal cartel activities, local economic conditions, political disruption, and governmental policies that may:

- disrupt our operations;
- restrict the movement of funds or limit repatriation of profits;
- in the case of our non-U.S. operations, lead to U.S. government or international sanctions; and
- limit access to markets for periods of time.

Disruptions may occur in the future, and losses caused by these disruptions may not be covered by insurance. Consequently, our exploration, development and production activities may be substantially affected by factors that could have a material adverse effect on our financial condition and results of operations. Furthermore, in the event of a dispute arising from non-U.S. operations, we may be subject to the exclusive jurisdiction of courts outside the United States or may not be successful in subjecting non-U.S. persons to the jurisdiction of courts in the United States, which could adversely affect the outcome of such dispute.

Our operations are adversely affected by laws and policies of the jurisdictions, including Mexico, the United States, the Netherlands and other jurisdictions, in which we do business that affect foreign trade and taxation. Changes in any of these laws or policies or the implementation thereof could have a material adverse effect on our results of operations and financial position.

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 failing 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.

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 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 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.

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.

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 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.

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 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, political events in the United States or Mexico 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 and operations related to those jurisdictions. Our after-tax profitability could be affected by numerous factors, including the availability of tax credits, exemptions 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, 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. The United States recently enacted tax reform legislation in Public Law No. 115-97, commonly referred to as the Tax Cuts and Jobs Act. Additionally, the Multilateral Convention to Implement Tax Treaty Related Measures to Prevent BEPS recently entered into force among the jurisdictions that have ratified it. Both of these recent changes could result in further changes to our global taxation. These tax reforms provided for new and complex provisions that significantly change how the United States and other jurisdictions tax entities and operations, and those provisions are subject to further legislative change and administrative guidance and interpretation, all of which may differ from our interpretation. Additionally, Mexico recently elected a new president, Andrés Manuel López Obrador, who took office on December 1, 2018. His political party, *Movimiento Regeneración Nacional*, has a majority in both houses of Mexico's congress. However, it is unclear at this time what changes (if any) to the taxation of our income and operations will result from these political events in Mexico. Future tax reforms in Mexico as a result of these political events or in any other jurisdictions in which we operate now or in the future could also adversely impact our after-tax profitability.

Future regulations relating to and interpretations of recently enacted U.S. federal income tax legislation may vary from our current interpretation of such legislation.

The U.S. federal income tax legislation recently enacted in Public Law No. 115-97, commonly referred to as the Tax Cuts and Jobs Act, is highly complex and subject to interpretation. The presentation of our financial condition and results of operations is based upon our current interpretation of the provisions contained in the Tax Cuts and Jobs Act. In the future, the Treasury Department and the Internal Revenue Service are expected to release regulations relating to and interpretive guidance of the legislation contained in the Tax Cuts and Jobs Act. Any significant variance of our current interpretation of such legislation from any future regulations or interpretive guidance could result in a change to the presentation of our financial condition and results of operations and could negatively affect our business.

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

Climate change continues to attract considerable public 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 GHGs. 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, no comprehensive climate change legislation has been implemented. The EPA, however, has adopted regulations to restrict emissions of GHGs under existing provisions of the federal CAA. The EPA has adopted rules regulating GHG emissions under the existing CAA, including a rule requiring emissions of GHGs from certain large stationary sources through preconstruction and operating permit requirements.

The EPA has also adopted rules requiring the reporting of GHG emissions from specified large GHG emission sources in the United States, on an annual basis. Recent regulation of emissions of GHGs has focused on fugitive methane emissions. The EPA has also taken steps to limit methane emissions, a GHG, from certain new modified or reconstructed facilities in the oil and natural gas sector through the adoption of a final rule in June 2016 establishing Subpart OOOOa standards for methane emissions. However, in 2017, the EPA published a proposed rule to stay certain portions of these Subpart OOOOa standards for two years but the rule was not finalized. Rather, in February 2018, the EPA finalized amendments to certain requirements of the June 2016 final rule, and in September 2018 the EPA proposed additional amendments, including rescission of certain requirements and revisions to other requirements, such as fugitive emission monitoring frequency. In the event that the EPA's June 2016 rule should remain or be placed in effect, or should any other new methane emission standards be imposed on the oil and natural gas sector, such requirements could result in increased costs to our operations as well as result in restrictions, delays or cancellations in such operations, which costs, restrictions, delays or cancellations could adversely affect our business.

In addition, while the United States Congress has not taken any legislative action to reduce emissions of GHGs, many states have established GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG emission reduction goal.

Additionally, the United States is one of almost 200 nations that, in December 2015, agreed to the Paris Agreement, an international climate change agreement in Paris, France that calls for countries to set their own GHG emissions targets and be transparent about the measures each country uses to achieve its GHG emissions targets. The Paris Agreement entered into force on November 4, 2016. However, in August 2017, the U.S. State Department officially informed the United Nations of the intent of the United States to withdraw from the Paris Agreement. The Paris Agreement provides for a four-year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States' adherence to the exit process is uncertain and/or the terms on which the United States may reenter the Paris Agreement or a separately negotiated agreement are unclear at this time.

The adoption of legislation or regulatory programs to reduce 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 to comply with new regulatory or reporting requirements. Substantial limitations on GHG emissions could also adversely affect demand for the oil and natural gas we produce and lowers the value of our reserves. Consequently, legislation and regulatory programs to reduce emissions of GHG could have an adverse effect on our business, financial condition and results of operations. Additionally, with concerns over GHG emissions, certain non-governmental activists have recently directed their efforts at advocating the shifting of funding away from companies with energy-related assets, which could result in limitations or restrictions on certain sources of funding for the energy sector.

In addition, claims have been made against certain energy companies alleging that GHG emissions from oil and natural gas operations constitute a public nuisance under federal and/or state common law. As a result, private individuals or public entities may seek to enforce environmental laws and regulations against us and could allege personal injury, property damage, or other liabilities. 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.

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 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.

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 natural gas liquids, we periodically enter into oil, natural gas and natural gas liquids price hedging arrangements with respect to a portion of our expected production. Our hedging 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 natural gas liquids of proved developed producing ("PDP") volumes during months January through July and November through December, (ii) 65% of the reasonably anticipated quarterly production of oil, natural gas and natural gas liquids of PDP volumes during months August through October, (iii) 50% of the reasonably anticipated quarterly production of oil, natural gas and natural gas liquids 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 natural gas liquids 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.

A majority of 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.

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.

Immediately following the closing of the Stone Combination, the Apollo Funds and Riverstone Funds beneficially owned and possessed voting power over 63% 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, 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 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 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.

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.

The corporate opportunity provisions in our Amended and Restated Certificate of Incorporation could enable others to benefit from corporate opportunities that might 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 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 of the State of Delaware 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. 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.

The Apollo Funds and the Riverstone Funds are prohibited from transferring a portion of their shares of our common stock until the first anniversary of the Closing Date, after which, subject to restrictions, they will be permitted to transfer their shares of our common stock, which could have a negative impact on our stock price.

Pursuant to the Stockholders' Agreement, and unless approved by a majority of our Independent Directors (as defined in the Stockholders' Agreement), the Apollo Funds and the Riverstone Funds will be restricted from transferring, other than to an affiliate, 25% of the respective shares of our common stock held by each on the Closing Date, until May 10, 2019. Beginning on May 10, 2019, the lock-up will cease to apply and the Apollo Funds and the Riverstone Funds will be permitted, subject to certain restrictions, to transfer such shares of our common stock, including in public offerings pursuant to registration rights granted by us. Any such transfer could significantly increase the number of shares of our common stock available in the market, which could cause a decrease in the price of our common stock.

Additionally, pursuant to the Stockholders' Agreement, until the first anniversary of the Closing Date, each of the Apollo Funds and the Riverstone Funds will be prohibited from transferring any shares of our common stock in any transaction that would result in the transferee owning more than 35% of the outstanding shares of our common stock without the prior approval of a majority of our Independent Directors, unless such transferee agrees in writing to be bound by substantially the same provisions as the stockholders are bound by pursuant to the Stockholders' Agreement. Following the first anniversary of the Closing Date, the Apollo Funds and the Riverstone Funds could sell a significant percentage of our common stock to a third party that is not subject to provisions similar to the provisions in the Stockholders' Agreement.

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 FERC under ICA. The ICA requires that we maintain a tariff on file with 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 FERC, should the pipeline's circumstances change, 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 FERC were to determine that CKB Petroleum, Inc. no longer qualified for a waiver, we would likely be required to file a tariff with 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 Pipeline could adversely affect our results of operations.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Information regarding our properties is included in Part I, Item 1. Business, Part II, Item 8. Financial Statements and Supplemental Data — 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 January 6, 2016, ERT plead guilty to two violations of the Clean Water for self-reported activities surrounding overboard discharge sampling and unpermitted discharges and two violations of OSCLA. On April 6, 2016, the United States District Court for the Eastern District of Louisiana accepted ERT's plea and sentenced ERT, consistent with the plea agreement, to pay a penalty of $4.2 million which ERT has paid. The Court placed ERT on probation for three years. The conditions of probation include compliance with an agreed Safety and Environmental Compliance Program. As a result of ERT's conviction for violations of the CWA, ERT was debarred and cannot enter into contracts with or receive benefits from the federal government, until the EPA reinstates ERT by certifying that ERT has corrected the conditions giving rise to the Clean Water convictions. EPA also imposed discretionary suspension and proposed debarment on Talos Production LLC, Talos Energy Offshore LLC and Talos Energy LLC as affiliates of ERT. On November 23, 2016, EPA terminated and administratively closed the suspension as to each of the three entities previously suspended. On August 29, 2017, EPA certified that the conditions giving rise to ERT's conviction were corrected, and its debarment was lifted.

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

On November 17, 2014, the Pennsylvania Department of Environmental Protection ("PADEP") issued a Notice of Violation ("NOV") to Stone alleging releases of production fluid and an improper closure of a drill cuttings pit at Stone's Loomis No. 1 well site in Susquehanna County, Pennsylvania. Prior to this, in September 2014, Stone had transferred ownership of the Loomis No. 1 well site to Southwestern Energy Company ("Southwestern"). PADEP approved the transfer on November 24, 2014, after issuing the NOV to Stone. Stone investigated the allegations found in the NOV and responded to PADEP on January 5, 2015. Reclamation of the site by Southwestern, with the participation of the PADEP and Stone, was completed. The PADEP may impose a penalty in this matter, but the amount of such penalty cannot be reasonably estimated at this time.

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 II, Item 8. Financial Statements and Supplementary Data — Note 11 — *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" since the Closing Date. Prior to the Closing Date, there was no public market for our equity securities.

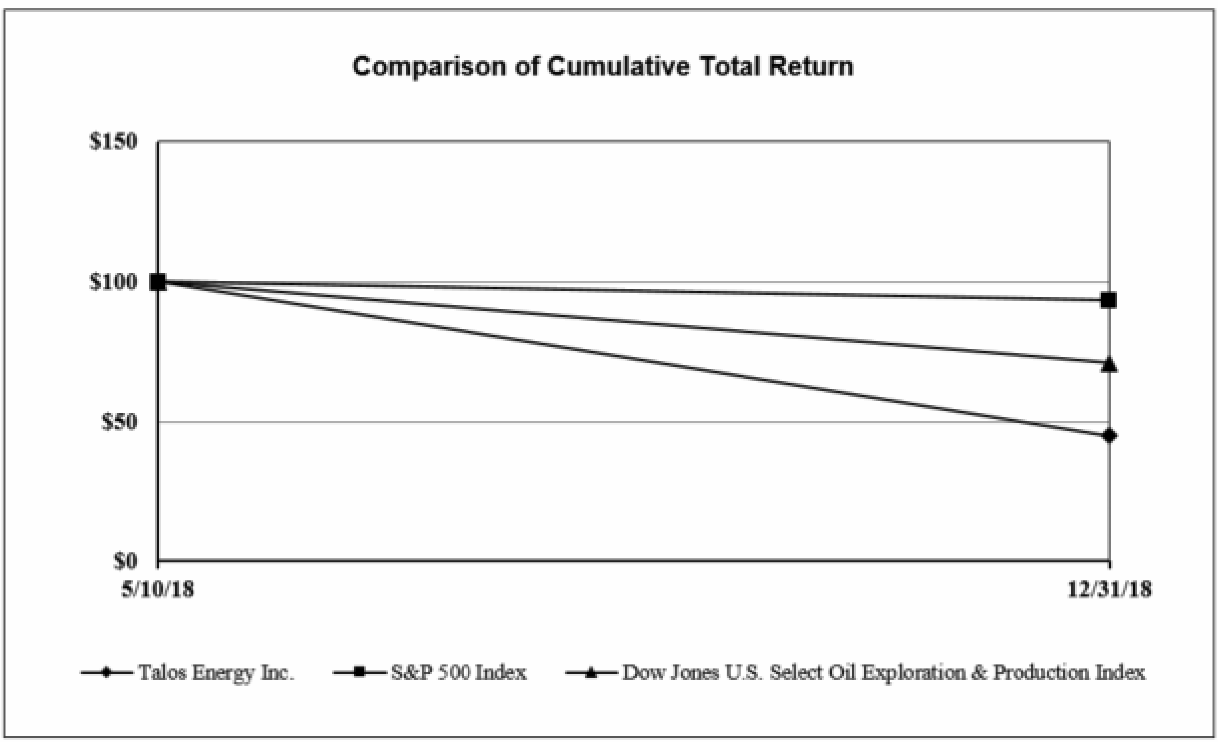
Holders of Record

Pursuant to the records of our transfer agent, as of March 6, 2019, there were approximately 308 holders of record of our common stock.

For additional information about shares authorized for issuance under equity compensation plans, see Part II, Item 8. Financial Statements and Supplementary Data — Note 7 — *Employee Benefits Plans and Share-Based Compensation*.

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 since May 10, 2018 through December 31, 2018. 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	December 31, 2018
Talos Energy Inc.	$ 100	$ 45
S&P 500 Index	100	93
Dow Jones U.S. Exploration and Production Index	100	71

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, 2018, 2017 and 2016 and the selected historical balance sheet data as of December 31, 2018 and 2017, have been derived from our audited consolidated financial statements and related notes for the year ended December 31, 2018, which are included elsewhere in this report. The selected historical statement of operations data for the years ended December 31, 2015 and 2014, and the selected historical balance sheet data as of December 31, 2016, 2015 and 2014 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 became our wholly-owned subsidiaries on the Closing Date in connection with the Stone Combination. Prior to the Closing Date, Talos Energy Inc. had not conducted any material activities other than those incident to its incorporation and certain matters contemplated by the Transaction Agreement. Talos Energy is the acquirer of Stone for financial reporting and accounting purposes. Talos Energy was considered the accounting acquirer in the Transactions under GAAP. Accordingly, the selected consolidated historical financial data presented in the tables below, which covers periods prior to the Closing Date, reflects the assets, liabilities and operations of Talos Energy prior to the Closing Date and does not reflect the assets, liabilities and operations of Stone prior to the Closing Date. In addition, we incurred material costs associated with the Transactions that are reflected in our historical results of operations for periods prior to the Closing Date, and Talos Energy 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.

	Year Ended December 31,				
	2018[(1)]	2017[(1)]	2016[(1)]	2015	2014
	(in thousands)				
Consolidated statements of operations data:					
Revenues:					
Oil revenue	$ 781,815	$ 344,781	$ 197,583	$ 244,167	$ 473,900
Natural gas revenue	73,610	48,886	42,705	55,026	63,201
NGL revenue	35,863	16,658	9,532	10,523	18,269
Other	—	2,503	8,934	5,890	6,205
Total revenue	$ 891,288	$ 412,828	$ 258,754	$ 315,606	$ 561,575
Operating income (loss)	$ 253,129	$ 45,300	$ (80,679)	$ (777,651)	$ 109,110
Net income (loss)	$ 221,540	$ (62,868)	$ (208,087)	$ (646,685)	$ 309,419
Net income (loss) per common share:					
Basic	$ 4.81	$ (2.01)	$ (7.99)	$ (26.20)	$ 15.20
Diluted	$ 4.81	$ (2.01)	$ (7.99)	$ (26.20)	$ 15.20
Weighted average common shares outstanding:					
Basic	46,058	31,244	26,036	24,685	20,358
Diluted	46,061	31,244	26,036	24,685	20,358
Consolidated balance sheets data (at period end):					
Total assets	$2,479,986	$1,239,293	$1,212,298	$1,194,842	$1,697,240
Total debt[(2)]	$ 655,304	$ 697,558	$ 701,175	$ 690,178	$ 595,492
Stockholders' equity (deficit)	$1,007,496	$ (54,087)	$ 6,986	$ 120,895	$ 690,502

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

(2) In April 2015, the FASB issued ASU 2015-03, Interest—Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs. The amendment changes the presentation of long-term debt issuance costs in the financial statements, and was adopted by Talos Energy during the first quarter of 2016 and applied retrospectively to December 31, 2015 and 2014 as presented above.

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

Our Business

We are a technically driven independent exploration and production company with operations in the United States Gulf of Mexico and offshore Mexico. Our focus in the United States Gulf of Mexico is the acquisition of deepwater assets with existing infrastructure and the exploration, exploitation and development of such assets in key geologic trends. Offshore Mexico provides us high impact exploration opportunities in an emerging basin. We use our access to an extensive seismic database and our deep technical expertise to identify, acquire and exploit attractive assets with robust economic profiles. Our management and technical teams have a long history working together and have made significant discoveries in the deep waters of the Gulf of Mexico and offshore Mexico.

On the Closing Date, we acquired Stone, an independent oil and natural gas company engaged in the acquisition, exploration, exploitation, development and operation of oil and gas properties. The Stone properties acquired in the Stone Combination are located primarily in the deep water of the Gulf of Mexico, with limited exposure to Gulf of Mexico conventional shelf and deep gas properties. As of the closing of the Stone Combination, Stone's property portfolio consisted primarily of nine active properties and 34 primary term leases in the Gulf of Mexico Basin. For more information on the Stone Combination, please read Part I, Item 1 and 2. Business and Properties.

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 or are acquisition or joint venture opportunities. We add to and reevaluate our inventory in order to deploy our capital as efficiently as possible.

We plan to opportunistically expand our asset base by evaluating the robust supply of acquisition opportunities in the Gulf of Mexico. The acquisition strategy is focused on deep and shallow water assets with a geological setting which we believe can benefit from our access to an extensive seismic database and our reprocessing expertise to reevaluate the acquired assets. We expect to target acquisitions involving assets with physical infrastructure that will allow us to focus on additional drilling opportunities. By applying a disciplined valuation methodology, we seek to reduce the risk of acquired property underperformance while maintaining potential for higher returns on our investment. In addition, we may consider acquisition opportunities in other offshore basins with analogous geologies that are suitable for our operational and technical expertise to the extent we believe it will increase our reserves and enhance returns on our investment and long-term growth prospects.

Recent Developments

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. The Zama appraisal campaign is expected to be completed by approximately mid-year 2019. If the appraisal of the Zama field confirms our initial estimates, we expect to announce a Final Investment Decision in 2020, following Mexican government approval of the development plan. In addition to Zama, other prospects are being analyzed and matured to potentially be drilled over the next several years.

In September 2018, we entered into a transaction the Hokchi Cross Assignment with Hokchi, to cross assign 25% PIs in Block 2 and Block 31. Our assignment of a 25% PI in Block 2 to Hokchi closed on December 21, 2018, and Hokchi has assumed operator responsibilities with respect to Block 2. Hokchi's assignment of Block 31 to us will be completed upon final approval by the CNH, Mexico's upstream regulator. In addition, Premier exercised its option to reduce its PI in Block 2 to zero and assign a 5% PI to each of Sierra and us. Such assignment is also subject to CNH's approval. Upon completion of the Hokchi Cross Assignment and Premier's option exercise, we will own a 25% PI in each of Block 2 and Block 31, and Hokchi will be the operator of both blocks.

In February 2019, CHN granted approval for drilling in the Acan prospect in Block 2. Hokchi intends to start drilling in March 2019. Soon thereafter, we plan to participate in two prospects in Block 31. Beyond the Acan prospects, we believe that Blocks 2 and 31 contain a significant portfolio of compelling prospects with strong technical ties to offsetting discoveries.

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

Stone Combination

As previously described, Stone and Talos Energy became our wholly-owned subsidiaries on the Closing Date. Prior to the Closing Date, Talos Energy Inc. had not conducted any material activities other than those incident to its incorporation and certain matters contemplated by the Transaction Agreement. Talos Energy is the acquirer of Stone for financial reporting and accounting purposes and considered the accounting acquirer in the Transactions under GAAP. Accordingly, our historical financial and operating data, which covers periods prior to the Closing Date, reflects the assets, liabilities and results of operations of Talos Energy prior to the Closing Date and does not reflect the assets, liabilities and results of operations of Stone prior to the Closing Date. See Part II, Item 8. Financial Statements and Supplementary Data — Note 3 — *Acquisitions* for more information.

Whistler Acquisition

On August 31, 2018, we completed the acquisition of all the issued and outstanding membership interests of Whistler from Whistler Energy II Holdco, LLC for \$52.6 million (\$14.8 million net of \$37.8 million of cash acquired). See Part II, Item 8. Financial Statements and Supplementary Data — Note 3 — *Acquisitions* for more information.

Sojitz Acquisition

On December 20, 2016, we purchased an additional 15% working interest in the Phoenix Field from Sojitz Energy Venture, Inc. for approximately \$85.8 million in cash and the assumption of certain asset retirement obligations, subject to customary post-closing adjustments. The purchase price was funded by a \$93.8 million (\$91.9 million, net of \$1.9 million of transaction fees) contribution from the Sponsors. Additionally, we entered into a contingent consideration arrangement in the form of an earn-out equal to 5% of the acquired property's monthly net profit if our realized oil price is greater than \$65.00 per Bbl in a given month. The maximum payout under the earn-out is \$10.0 million and has an indefinite life pursuant to the purchase and sale agreement. See Part II, Item 8. Financial Statements and Supplementary Data — Note 3 — *Acquisitions* for more information.

Transaction Expenses

We have incurred and will continue to incur transaction related and restructuring costs associated with the Stone Combination and the integration of the businesses of Stone and Talos Energy that are not reflected in our comparative historical results of operations.

Income Tax Expenses

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 were conducted under a different legal form and are subject to foreign income taxes.

In connection with the Stone Combination, Talos Energy LLC was contributed to us. We are subject to federal and state income taxes. We record current income taxes based on estimates of current taxable income and provide for deferred income taxes to reflect estimated future income tax payments and receipts.

Third Party Planned Downtime

Since our operations are offshore, we are vulnerable to third party downtime events impacting the transportation, gathering or processing of production. We produce the Phoenix Field through the HP-I that is operated by 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. In January 2019, Helix dry-docked the HP-I for inspection and the shut-in is expected to last until March 2019. For the year ended December 31, 2018, the Phoenix Field produced 17.9 MBoepd. The impact of the shut-in on the first quarter of 2019 production is estimated to be between 9.0 MBoepd and 13.0 MBoepd, whereas the annualized impact for full year 2019 is expected to be between 2.0 MBoepd and 3.0 MBoepd. In the current commodity price environment, the shut-in represents an estimated cash flow impact of \$35.0 million to \$55.0 million, primarily in the first quarter of 2019.

Known Trends and Uncertainties

Volatility in Oil, Natural Gas and NGL Prices. Historically, the markets for oil and natural gas have been volatile. 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 response to relatively minor changes in supply and demand.

BOEM Bonding Requirements. In order to cover the various decommissioning obligations of lessees on the OCS, 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 July 2016, BOEM issued the NTL 2016-N01 ("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 became effective in September 2016, but BOEM subsequently postponed any implementation of the 2016 NTL and has indicated they will be issuing a modified or substitute NTL. This extension for implementation currently remains in effect. We remain in active discussions with government regulators and industry peers with regard to any future rulemaking and financial assurance requirements. Notwithstanding BOEM's 2016 NTL, BOEM may also bolster its financial assurance requirements mandated by rule for all companies operating in federal waters. The future cost of compliance with respect to supplemental bonding, including the obligations imposed on us as a result of the 2016 NTL, to the extent implemented, as well as any other future BOEM directives, or any other changes to BOEM's rules applicable to our or any of our subsidiaries' properties, could materially and adversely affect our financial condition, cash flows and results of operations.

Deepwater Operations. We have interests in deepwater fields in the 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 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 been 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 P&A 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.

Basis of Presentation

Sources of Revenues

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 in our consolidated statements of operations. The following table presents a breakout of each revenue component:

	Year Ended December 31,		
	2018	2017	2016
Revenue breakout:			
Oil revenue	88%	83%	76%
Natural gas revenue	8%	12%	17%
NGL revenue	4%	4%	4%
Other	—%	1%	3%

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. Similar to oil, 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 and natural gas sales prices for the periods indicated.

	Year Ended December 31,		
	2018	2017	2016
Oil:			
NYMEX WTI High per Bbl	$ 70.76	$ 57.95	$ 52.17
NYMEX WTI Low per Bbl	48.98	45.20	30.62
Average NYMEX WTI per Bbl	64.77	50.95	43.32
Average Oil Sales Price per Bbl (including commodity derivatives)	57.12	52.46	68.46
Average Oil Sales Price per Bbl (excluding commodity derivatives)	66.42	48.92	38.55
Natural Gas:			
NYMEX Henry Hub High per MMBtu	$ 4.72	$ 3.93	$ 3.23
NYMEX Henry Hub Low per MMBtu	2.64	2.63	1.71
Average NYMEX Henry Hub per MMBtu	3.09	3.11	2.46
Average Natural Gas Sales Price per Mcf (including commodity derivatives)	3.16	2.93	3.24
Average Natural Gas Sales Price per Mcf (excluding commodity derivatives)	3.23	3.00	2.25
NGLs:			
NGL Realized Price as a % of Average NYMEX WTI	47%	46%	36%

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, in a portion of our current positions, 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

Direct lease operating expense. Direct 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, HP-I lease, materials and supplies, rental and third party costs comprise the most significant portion of our direct lease operating expense. In July 2016, we executed a new contract for the HP-I accounted for as a capital lease, thus reducing the amount recorded as direct lease operating expenses going forward.

Insurance expense. Insurance expense consists of the cost of 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 based on our estimated loss potential. Our significant domestic and international policies include general liability, physical damage to our oil and gas properties, operational control of well, named Gulf of Mexico windstorm and oil pollution.

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.

Workover and maintenance expense. Workover and maintenance expense 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.

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 II, Item 8. Financial Statements and Supplementary Data — 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

Comparison of the Year Ended December 31, 2018 and 2017

The information below provides the financial results and an analysis of significant variances in these results for the year ended December 31, 2018 and 2017 (in thousands):

	Year Ended December 31,			
	2018	2017	Change	% Change
Revenues:				
Oil revenue	$ 781,815	$ 344,781	$ 437,034	127%
Natural gas revenue	73,610	48,886	24,724	51%
NGL revenue	35,863	16,658	19,205	115%
Other	—	2,503	(2,503)	(100)%
Total revenue	891,288	412,828	478,460	116%
Operating expenses:				
Direct lease operating expense	145,988	109,180	36,808	34%
Insurance	15,342	10,743	4,599	43%
Production taxes	1,989	1,460	529	36%
Total lease operating expense	163,319	121,383	41,936	35%
Workover / maintenance expense	64,961	32,825	32,136	98%
Depreciation, depletion and amortization	288,719	157,352	131,367	83%
Accretion expense	35,344	19,295	16,049	83%
General and administrative expense	85,816	36,673	49,143	134%
Total operating expenses	638,159	367,528	270,631	74%
Operating income (loss)	253,129	45,300	207,829	459%
Interest expense	(90,114)	(80,934)	(9,180)	(11)%
Price risk management activities income (expense)	60,435	(27,563)	87,998	319%
Other income	1,012	329	683	208%
Net income (loss) before income taxes	$ 224,462	$ (62,868)	$ 287,330	457%
Income tax expense	(2,922)	—	(2,922)	(100)%
Net income (loss)	$ 221,540	$ (62,868)	$ 284,408	452%

The table below provides additional detail of our oil, natural gas and NGL production volumes and sales prices per unit.

	Year Ended December 31, 2018	Year Ended December 31, 2017	Change
Oil production volume (MBbls)	11,771	7,048	4,723
Average daily oil production volume (MBblpd)	32.2	19.3	12.9
Oil sales revenue (in thousands)	$ 781,815	$ 344,781	$ 437,034
Average oil sales price per Bbl (including commodity derivatives)	$ 57.12	$ 52.46	$ 4.66
Average oil sales price per Bbl (excluding commodity derivatives)	$ 66.42	$ 48.92	$ 17.50
Average NYMEX WTI price per Bbl	$ 64.77	$ 50.95	$ 13.82
Increase in oil sales revenue due to:			
Change in net realized prices (in thousands)	$ 205,985		
Change in production volume (in thousands)	231,049		
Total increase in oil sales revenue (in thousands)	$ 437,034		
Natural gas production volume (MMcf)	22,771	16,308	6,463
Average daily natural gas production volume (MMcfpd)	62.4	44.7	17.7
Natural gas sales revenue (in thousands)	$ 73,610	$ 48,886	$ 24,724
Average natural gas sales price per Mcf (including commodity derivatives)	$ 3.16	$ 2.93	$ 0.23
Average natural gas sales price per Mcf (excluding commodity derivatives)	$ 3.23	$ 3.00	$ 0.23
Average NYMEX Henry Hub price per MMBtu	$ 3.09	$ 3.11	$ (0.02)
Increase in natural gas sales revenue due to:			
Change in net realized prices (in thousands)	$ 5,335		
Change in production volume (in thousands)	19,389		
Total increase in natural gas sales revenue (in thousands)	$ 24,724		
NGL production volume (MBbls)	1,176	706	470
Average daily NGL production volume (MBblpd)	3.2	1.9	1.3
NGL sales revenue (in thousands)	$ 35,863	$ 16,658	$ 19,205
Average NGL sales price per Bbl	$ 30.50	$ 23.59	$ 6.91
Increase in NGL sales revenue due to:			
Change in net realized prices (in thousands)	$ 8,118		
Change in production volume (in thousands)	11,087		
Total increase in NGL sales revenue (in thousands)	$ 19,205		
Total production volume (MBoe)	16,742	10,472	6,270
Average daily total production volume (MBoepd)	45.9	28.7	17.2
Price per Boe (including commodity derivatives)	$ 46.60	$ 41.46	$ 5.14
Price per Boe (excluding commodity derivatives)	$ 53.24	$ 39.18	$ 14.06

The following table highlights 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 year ended December 31, 2018 and 2017 (in thousands, except per Boe data):

	Year Ended December 31,			
	2018		2017	
	Total	Per Boe	Total	Per Boe
Lease operating expenses:				
Direct lease operating expense	$ 145,988	$ 8.72	$ 109,180	$ 10.43
Insurance	15,342	0.92	10,743	1.03
Production taxes	1,989	0.12	1,460	0.14
Total lease operating expenses	163,319	9.76	121,383	11.60
Depreciation, depletion and amortization	288,719	17.24	157,352	15.03
General and administrative expense	85,816	5.13	36,673	3.50
Other operating expenses:				
Workover / maintenance expense	64,961	3.88	32,825	3.13
Accretion expense	35,344	2.11	19,295	1.84
Total other operating expenses	100,305	5.99	52,120	4.97
Total operating expenses	$ 638,159	$ 38.12	$ 367,528	$ 35.10

Revenue. Total revenue for the year ended December 31, 2018 was $891.3 million compared to $412.8 million for the year ended December 31, 2017, an increase of approximately $478.5 million or 116%.

Oil revenue increased by approximately $437.0 million, or 127%, during the year ended December 31, 2018 compared to the corresponding period in 2017. This increase was primarily due to an increase of $17.50 per Bbl in our realized oil sales price and a 12.9 MBblpd increase in oil production volumes. The increase in oil production volumes was attributable to 11.7 MBblpd from the Stone Combination and the Whistler Acquisition collectively, and 3.2 MBblpd from the Tornado II well in the Phoenix Field which commenced initial production in December 2017. The increase in production was partially offset by unplanned third party downtime.

Natural gas revenue increased by approximately $24.7 million, or 51%, during the year ended December 31, 2018 compared to the corresponding period in 2017. This increase was due to a 17.7 MMcfpd increase in gas production volumes, which was attributable to 18.2 MMcfpd from the Stone Combination and Whistler Acquisition collectively. Natural gas revenue also increased due to a $0.23 per Mcf increase in our realized gas sales price.

NGL revenue increased by approximately $19.2 million, or 115%, during the year ended December 31, 2018 compared to the corresponding period in 2017. This increase was due to an increase of a $6.91 per Bbl increase in our realized NGL sales price and a 1.3 MBblpd increase in NGL volumes, 1.2 MBblpd of which was attributable to the Stone Combination and Whistler Acquisition collectively.

Lease operating expense. Total lease operating expense for the year ended December 31, 2018 was $163.3 million compared to $121.4 million for the year ended December 31, 2017 an increase of approximately $41.9 million, or 35%. This increase was primarily related to $40.7 million of lease operating expense in connection with the Stone Combination and $2.8 million of lease operating expense in connection with the Whistler Acquisition. In addition, lease operating expense increased due to a more competitive offshore environment, offset by an $8.7 million increase in PHA reimbursements. While total lease operating expense has increased, lease operating expense decreased $1.84 per Boe to $9.76 per Boe as a result of increased deepwater production from the Stone Combination and increased production in the Phoenix Field.

Depreciation, depletion and amortization. Depreciation, depletion and amortization expense for the year ended December 31, 2018 was $288.7 million compared to $157.3 million for the year ended December 31, 2017, an increase of approximately $131.4 million, or 83%. This increase was primarily due to a $2.22 per Boe, or 15%, increase in the depletion rate on our proved oil and natural gas properties during the year ended December 31, 2018. Depletion on a per Boe basis increased primarily due to an increase in proved properties related to the Stone Combination and higher estimated future development costs related to proved undeveloped reserves in the Phoenix Field.

General and administrative expense. General and administrative expense for the year ended December 31, 2018 was $85.8 million compared to $36.7 million for the year ended December 31, 2017, an increase of approximately $49.1 million, or 134%. This increase was primarily attributable to $29.2 million in transaction related costs related to the Stone Combination and $16.4 million in additional payroll cost and additional general and administrative expenses as a result of the combined company.

Other operating expense. Other operating expense for the year ended December 31, 2018 was $100.3 million compared to $52.1 million for year ended December 31, 2017, an increase of approximately $48.2 million, or 92%. This increase was primarily related to an increase of approximately $32.1 million and an increase of approximately $16.0 million in workover and maintenance expense and accretion expense, respectively, in connection with the Stone Combination.

Price risk management activities. Price risk management activities for year ended December 31, 2018 resulted in income of $60.4 million compared to an expense of $27.6 million for the year ended December 31, 2017. The income of $60.4 million for the year ended December 31, 2018 consists of $111.1 million in cash settlement losses offset by $171.6 million in non-cash gains from the increase in the fair value of our open derivative contracts. The expense of $27.6 million for the year ended December 31, 2017 consists of cash settlement gains of $23.8 million offset by a $51.4 million in non-cash losses from the decrease in the fair value of our open derivatives 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 2019, we expect these activities to continue to impact net income (loss) based on fluctuations in market prices for oil and natural gas.

Comparison of the Year Ended December 31, 2017 and 2016

The information below provides the financial results and an analysis of significant variances in these results for the year ended December 31, 2017 and 2016 (in thousands):

	Year Ended December 31,			
	2017	2016	Change	% Change
Revenues:				
Oil revenue	$ 344,781	$ 197,583	$ 147,198	74%
Natural gas revenue	48,886	42,705	6,181	14%
NGL revenue	16,658	9,532	7,126	75%
Other	2,503	8,934	(6,431)	(72)%
Total revenue	412,828	258,754	154,074	60%
Operating expenses:				
Direct lease operating expense	109,180	124,360	(15,180)	(12)%
Insurance	10,743	13,101	(2,358)	(18)%
Production taxes	1,460	1,958	(498)	(25)%
Total lease operating expense	121,383	139,419	(18,036)	(13)%
Workover / maintenance expense	32,825	24,810	8,015	32%
Depreciation, depletion and amortization	157,352	124,689	32,663	26%
Accretion expense	19,295	21,829	(2,534)	(12)%
General and administrative expense	36,673	28,686	7,987	28%
Total operating expenses	367,528	339,433	28,095	8%
Operating income (loss)	45,300	(80,679)	125,979	156%
Interest expense	(80,934)	(70,415)	10,519	15%
Price risk management activities income (expense)	(27,563)	(57,398)	29,835	52%
Other income	329	405	(76)	(19)%
Net loss	$ (62,868)	$ (208,087)	$ 145,219	70%

The table below provides additional detail of our production volumes and sales prices per unit.

	Year Ended December 31, 2017	Year Ended December 31, 2016	Change
Oil production volume (MBbls)	7,048	5,126	1,922
Average daily oil production volume (MBblpd)	19.3	14.0	5.3
Oil sales revenue (in thousands)	$ 344,781	$ 197,583	$ 147,198
Average oil sales price per Bbl (including commodity derivatives)	$ 52.46	$ 68.46	$ (16.00)
Average oil sales price per Bbl (excluding commodity derivatives)	$ 48.92	$ 38.55	$ 10.37
Average daily NYMEX WTI price per Bbl	$ 50.95	$ 43.32	$ 7.63
Increase in oil sales revenue due to:			
Change in prices (in thousands)	$ 73,105		
Change in production volume (in thousands)	74,093		
Total increase in oil sales revenue (in thousands)	$ 147,198		
Natural gas production volume (MMcf)	16,308	19,001	(2,693)
Average daily natural gas production volume (MMcfpd)	44.7	52.1	(7.4)
Natural gas sales revenue (in thousands)	$ 48,886	$ 42,705	$ 6,181
Average natural gas sales price per Mcf (including commodity derivatives)	$ 2.93	$ 3.24	$ (0.31)
Average natural gas sales price per Mcf (excluding commodity derivatives)	$ 3.00	$ 2.25	$ 0.75
Average daily NYMEX Henry Hub price per MMBtu	$ 3.11	$ 2.46	$ 0.65
Increase in natural gas sales revenue due to:			
Change in prices (in thousands)	$ 12,240		
Change in production volume (in thousands)	(6,059)		
Total increase in natural gas sales revenue (in thousands)	$ 6,181		
NGL production volume (MBbls)	706	603	103
Average daily NGL production volume (MBblpd)	1.9	1.7	0.2
NGL sales revenue (in thousands)	$ 16,658	$ 9,532	$ 7,126
Average NGL sales price per Bbl (excluding commodity derivatives)	$ 23.59	$ 15.81	$ 7.78
Increase in NGL sales revenue due to:			
Change in prices (in thousands)	$ 5,498		
Change in production volume (in thousands)	1,628		
Total increase in NGL sales revenue (in thousands)	$ 7,126		
Total production per Mboe	10,472	8,896	1,576
Average daily total production volume (MBoepd)	28.7	24.4	4.3
Price per Boe (including commodity derivatives)	$ 41.46	$ 47.44	$ (5.98)
Price per Boe (excluding commodity derivatives)	$ 39.18	$ 28.08	$ 11.10

The following table highlights 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, 2017 and 2016 (in thousands, except per Boe data):

	Year Ended December 31,			
	2017		2016	
	Total	Per Boe	Total	Per Boe[1]
Lease operating expenses:				
Direct lease operating expense	$ 109,180	$ 10.43	$ 124,360	$ 13.98
Insurance	10,743	1.03	13,101	1.47
Production taxes	1,460	0.14	1,958	0.22
Total lease operating expenses	121,383	11.60	139,419	15.67
Depreciation, depletion and amortization	157,352	15.03	124,689	14.02
General and administrative expense	36,673	3.50	28,686	3.22
Other operating expenses:				
Workover / maintenance expense	32,825	3.13	24,810	2.79
Accretion expense	19,295	1.84	21,829	2.45
Total other operating expenses	52,120	4.97	46,639	5.24
Total operating expenses	$ 367,528	$ 35.10	$ 339,433	$ 38.15

Revenue. Total revenue for the year ended December 31, 2017 was $412.8 million compared to $258.8 million for the year ended December 31, 2016, an increase of $154.0 million, or 60%. Oil revenue increased by $147.2 million, or 74%, during the year ended December 31, 2017. This increase was primarily due to an increase of $10.37 per Bbl in our realized oil sales price and 5.3 MBblpd increase in production volumes. The increase in production volumes primarily related to a 6.2 MBblpd increase from the Tornado well, GC 281 #1ST (T-9) in the Phoenix Field. Initial production commenced in October 2016.

Natural gas revenue increased by $6.2 million, or 14%, during the year ended December 31, 2017. The increase in natural gas revenue was due to a $0.75 per Mcf increase in our realized average natural gas sales price. This increase was offset by a 7.4 MMcfpd decrease in production during the year ended December 31, 2017 primarily due to third party pipeline maintenance and weather related downtime.

Other revenue decreased by $6.4 million, or 72%, during the year ended December 31, 2017 primarily due to production handling agreements fees, commencing in 2017 from certain working interest partners in the Phoenix Field which are recorded as a reduction to lease operating expense.

Lease operating expense. Total lease operating expense for the year ended December 31, 2017 was $121.4 million compared to $139.4 million for the year ended December 31, 2016, a decrease of $18.0 million, or 13%. The decrease was primarily attributed to a $14.3 million decrease in our production facility rental expense as a result of the newly negotiated seven year lease agreement with Helix for use of the HP-I beginning July 2016 which is accounted for as a capital lease, as well as a $2.4 million decrease in our insurance expense.

Depreciation, depletion and amortization. Depreciation, depletion and amortization expense for the year ended December 31, 2017 was $157.4 million and $124.7 million for the year ended December 31, 2016, an increase of $32.7 million, or 26%. The increase is primarily due to a $1.03 per Boe, or 7%, increase in the depletion rate on our proved oil and natural gas properties during the year ended December 31, 2017. Depletion on a per Boe basis increased primarily due to inclusion in the full cost pool of the capital lease asset recorded in July 2016 for use of the HP-I. Since the HP-I is utilized in our oil and natural gas development activities, the asset is included within proved property and thus depleted as part of the full cost pool.

General and administrative expense. General and administrative expense for the year ended December 31, 2017 was $36.7 million compared to $28.7 million for the year ended December 31, 2016, an increase of $8.0 million, or 28%. The increase was primarily attributable to $9.7 million in transaction related costs associated with the Stone Combination and our 2017 debt exchange, partially offset by a decrease in employee related expenses of $0.7 million.

Other operating expense. Other operating expense for the year ended December 31, 2017 was $52.1 million compared to $46.6 million for the year ended December 31, 2016, an increase of $5.5 million, or 12%. This increase was primarily related to an increase of $7.8 million in facility and major wellwork due to repairs on South Marsh Island 130. This is partially offset by a decrease of $2.5 million in accretion expense for asset retirement obligations settled in 2017.

Interest expense. Interest expense for the year ended December 31, 2017 was $80.9 million compared to $70.4 million for the year ended December 31, 2016, an increase of $10.5 million, or 15%. The change was primarily due to an increase of $11.5 million from the HP-I capital lease that began in July 2016.

Price risk management activities. Price risk management activities expense for the year ended December 31, 2017 was $27.6 million compared to $57.4 million for the year ended December 31, 2016. The decrease of $29.8 million was attributable to a $178.2 million increase in fair value of our open derivative contracts offset by a $148.2 million decrease in cash settlement gains for the year ended December 31, 2017. 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 in our consolidated statements of operations at the end of each month. As a result of the derivative contracts we have in place on our anticipated production volumes through 2019, we expect these activities to continue to impact net income (loss) based on fluctuations in market prices for oil and natural gas.

Commitments and Contingencies

For a further discussion of our commitments and contingencies, see Part II, Item 8. Financial Statements and Supplementary Data — Note 11 — *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 operation. See Part I, Item 3. Legal Proceedings for additional information.

Supplemental Non-GAAP Measure

Adjusted EBITDA

"Adjusted EBITDA" is not a measure of net income (loss) as determined by GAAP. We use this measure as a supplemental measure because we believe it provides meaningful information to our investors. We define Adjusted EBITDA as net income (loss) plus interest expense, income tax expense, depreciation, depletion and amortization, accretion expense, 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 oil and natural gas properties, non-cash write-down of other well equipment inventory and non-cash equity based compensation expense. We believe the presentation of Adjusted EBITDA is important 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. Adjusted EBITDA has limitations as an analytical tool and should not be considered in isolation or as a substitute for analysis of our results as reported under GAAP or as an alternative to net income (loss), operating income (loss) or any other measure of financial performance presented in accordance with GAAP.

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, except for Boe data):

	Year Ended December 31,		
	2018	2017	2016
Reconciliation of net income (loss) to Adjusted EBITDA:			
Net income (loss)	$ 221,540	$ (62,868)	$ (208,087)
Interest expense	90,114	80,934	70,415
Income tax expense	2,922	—	—
Depreciation, depletion and amortization	288,719	157,352	124,689
Accretion expense	35,344	19,295	21,829
Loss on debt extinguishment	1,764	—	—
Transaction related costs	32,484	9,652	135
Derivative fair value (gain) loss[(1)]	(60,435)	27,563	57,398
Net cash receipts (payments) on settled derivative instruments[(1)]	(111,147)	23,834	172,182
Non-cash (gain) loss on sale of assets	(1,710)	—	—
Non-cash write-down of other well equipment inventory	244	260	218
Non-cash equity-based compensation expense	2,893	875	1,083
Adjusted EBITDA	$ 502,732	$ 256,897	$ 239,862

(1) 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

Overview

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, 2018, our available liquidity (cash plus available capacity under the Bank Credit Facility) was $460.3 million.

As of December 31, 2018, total debt, net of discount and deferred financing costs, was approximately $655.3 million, comprised of our $381.2 million aggregate principal amount of the New Second Lien Notes and $6.1 million aggregate principal amount of our 7.50% Stone Senior Notes, $257.4 million outstanding under our Bank Credit Facility, and $10.6 million aggregate principal amount of the Building Loan. We were in compliance with all debt covenants at December 31, 2018. For additional details on our debt, see Part II, Item 8. Financial Statements and Supplementary Data — Note 6 — *Debt*.

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 2019 capital spending project of $465.0 million to $485.0 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.

As of December 31, 2018, we had obtained performance bonds primarily related to P&A of wells and removal of facilities in the United States Gulf of Mexico and to guarantee the completion of the minimum work program under the PSCs totaling approximately $644.1 million. In July 2016, BOEM issued the 2016 NTL to clarify the procedures and guidelines the BOEM Regional Directors use to determine if and when additional financial assurances may be required for OCS leases, ROWs and RUEs to meet BOEM's estimate of the lessees' decommissioning obligations. The 2016 NTL became effective in September 2016 and allows qualifying operators to self-insure for an amount up to 10% of their tangible net worth. The 2016 NTL also provides for operators to propose a tailored plan subject to BOEM approval that allows the posting of additional financial assurance over time. However, BOEM has indefinitely delayed beyond June 30, 2017 implementation of the 2016 NTL, except in certain circumstances where there is a substantial risk of nonperformance of the interest holder's decommissioning liabilities, to allow BOEM time to reconsider a number of regulatory initiatives. We received the BOEM 2016 Orders in late 2016 ordering us to secure financial assurances in the form of additional security in material amounts. We entered into discussions with BOEM regarding the requested security and submitted a proposed tailored plan for the posting of additional financial security to the agency for review. However, as noted, BOEM has indefinitely delayed implementation beyond June 30, 2017 of the 2016 NTL, has rescinded the BOEM 2016 Orders while BOEM reviews its financial assurance program and, to date, has taken no action with respect to our previously submitted proposed tailored plan. We remain in active discussion with our government regulators and industry peers with regard to any future rule making and financial assurance requirements. Notwithstanding the 2016 NTL, BOEM may also increase its financial assurance requirements mandated by rule for all companies operating in federal waters. BOEM could also make new demands for additional financial security in material amounts in the event the agency chooses to implement the 2016 NTL, and such amounts may be material and exceed our capability to provide additional financial assurance. The future cost of compliance with our existing supplemental bonding requirements, including with respect to any tailored plan that is subject to approval by BOEM, the 2016 NTL, as well as any other future directives or any other changes to BOEM's rules applicable to us or our subsidiaries' properties, could materially and adversely affect our financial condition, cash flows and results of operations.

New Second Lien Notes, 7.50% Stone Senior Notes

In connection with the Stone Combination, we consummated the Transactions contemplated by the Exchange Agreement, pursuant to which (i) the Apollo Funds and Riverstone Funds contributed $102.0 million in aggregate principal amount of 9.75% Senior Notes to us in exchange for our common stock; (ii) the holders of 11.00% Bridge Loans exchanged such 11.00% Bridge Loans for $172.0 million aggregate principal amount of New Second Lien Notes and (iii) the Franklin Noteholders and the MacKay Noteholders exchanged their 7.50% Stone Senior Notes for $137.4 million aggregate principal amount of New Second Lien Notes. An additional $81.5 million of 7.50% Stone Senior Notes held by non-affiliates were also exchanged for New Second Lien Notes pursuant to an exchange offer and consent solicitation in connection with the Stone Combination.

The exchange of 7.50% Stone Senior Notes for New Second Lien Notes was accounted for as a debt modification. Under a debt modification, a new effective interest rate that equates the revised cash flows to the carrying amount of the New Second Lien Notes is computed and applied prospectively. Costs incurred with third parties directly related to the modification are expensed as incurred. We incurred approximately $4.3 million of transaction fees related to the exchange of 11.00% Bridge Loans and 7.50% Stone Senior Notes into New Second Lien Notes, which were expensed and reflected in general and administrative expense during the year ended December 31, 2018, respectively. We also paid $9.3 million in work fees to debt holders, which are reflected as debt discount reducing long-term debt on the consolidated balance sheet at December 31, 2018.

11.00% Second-Priority Senior Secured Notes—due April 2022. The New Second Lien Notes were issued pursuant to an indenture dated as of the Closing Date, between the Talos Issuers, the subsidiary guarantors party thereto and Wilmington Trust, National Association, as trustee and collateral agent. The New Second Lien Notes mature April 3, 2022 and have interest payable semi-annually each April 15 and October 15. Prior to May 10, 2019, we may, at our option, redeem all or a portion of the New Second Lien Notes at 100% of the principal amount plus accrued and unpaid interest and a make-whole premium. Thereafter, we may redeem all or a portion of the New Second Lien Notes at redemption prices decreasing annually from 105.5% to 100.0% plus accrued and unpaid interest.

7.50% Senior Secured Notes—due May 2022. The 7.50% Stone Senior Notes represent the remaining $6.1 million of long-term debt assumed in the Stone Combination that were not exchanged for New Second Lien 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% Stone Senior Notes have been removed and collateral securing the 7.50% Stone Senior Notes has been released. The 7.50% Stone Senior Notes mature May 31, 2022 and have interest payable semiannually each May 31 and

November 30. Prior to May 31, 2020, we may, at our option, redeem all or a portion of the 7.50% Stone Senior Notes at 100% of the principal amount plus accrued and unpaid interest and a make-whole premium. Thereafter, we may redeem all or a portion of the 7.50% Stone Senior Notes at redemption prices decreasing annually from 105.625% to 100.0% plus accrued and unpaid interest.

Bank Credit Facility

Talos Production, our wholly owned subsidiary, executed the Bank Credit Facility in conjunction with the Stone Combination with a syndicate of financial institutions with an initial borrowing base of $600.0 million. The Bank Credit Facility is currently scheduled to mature on May 10, 2022.

The Bank Credit Facility bears interest based on the borrowing base usage, at the applicable London InterBank Offered Rate, plus applicable margins ranging from 2.75% to 3.75% or an alternate base rate based on the federal funds effective rate plus applicable margins ranging from 1.75% to 2.75%. In addition, we are obligated to pay a commitment fee of 0.50% on the unfunded portion of the commitments under the Bank Credit Facility. 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 each quarter. We must also maintain a current ratio no less than 1.00 to 1.00 each quarter. According to the Bank Credit Facility, undrawn 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. On November 16, 2018, the borrowing base was increased from $600.0 million to $850.0 million. We elected to maintain the $600.0 million commitment based upon our current liquidity needs. The next redetermination is scheduled for April 2019.

As of December 31, 2018, commitments under our borrowing base was set at $600.0 million, of which no more than $200 million 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, 2018. As of December 31, 2018, the Bank Credit Facility had approximately $320.3 million of undrawn commitments (taking into account $14.7 million letters of credit and $265.0 million drawn from the Bank Credit Facility).

Building Loan

In connection with the Stone Combination, we assumed Stone's Building Loan maturing on November 20, 2030. The Building Loan bears interest at a rate of 4.20% per annum and is to be repaid in 180 equal monthly installments of approximately $0.1 million. As of December 31, 2018, the outstanding balance under the Building Loan totaled $10.6 million. The Building Loan is collateralized by our two office buildings in Lafayette, Louisiana. Under the financial covenants of the Building Loan, we must maintain a ratio of EBITDA to Net Interest Expense of not less than 2.00 to 1.00. In addition, the Building Loan contains certain customary restrictions or requirements with respect to change of control and reporting responsibilities. We are in compliance with all covenants under the Building Loan as of December 31, 2018.

2018 Senior Notes

9.75% Senior Notes—due February 2018. The 9.75% Senior Notes due 2018 were issued by the Talos Issuers pursuant to an indenture dated February 6, 2013, among the Talos Issuers, the subsidiary guarantors party thereto and the trustee. On February 15, 2018, the Talos Issuers redeemed the remaining $25.0 million principal amount of the 9.75% Senior Notes due 2018 at par.

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,		
	2018	2017	2016
Operating activities	$ 263,445	$ 176,053	$ 116,123
Investing activities	$ 37,495	$ (157,641)	$ (198,918)
Financing activities	$ (193,211)	$ (18,412)	$ 91,624

Operating Activities. Net cash provided by operating activities increased $87.4 million in 2018 from 2017 primarily attributable to an increase in revenue, offset by a decrease in cash settlements on derivatives and transaction related cost related to the Stone Combination. Net cash provided by operating activities increased $59.9 million from 2017 to 2016 primarily due to an increase in revenue, offset by a decrease in cash settlements gains on our derivative contracts.

Investing Activities. Net cash used in (provided by) investing activities increased $195.1 million in 2018 from 2017 primarily attributable to $280.9 million of cash received from the Stone Combination and Whistler Acquisition, partially offset by an increase of $85.7 million in capital expenditures. The increase of $41.3 million in net cash used in investing activities from 2017 to 2016 primarily related to a decrease in capital expenditures.

Financing Activities. Net cash used in (provided by) financing activities increased by $174.8 million in 2018 from 2017 primarily attributable to the repayment of $403.0 million related to the LLC Bank Credit Facility, $54.0 million related to the repayment of the Bank Credit Facility, $25.3 million related to the redemption of our 2018 Senior Notes and other long-term debt, $17.0 million in deferred financing cost, partially offset by proceeds received from the Bank Credit Facility of $319.0 million. Net cash provided by financing activities decreased $110.0 million in 2017 from 2016 primarily related to a reduction of $91.9 million net contribution from our Sponsors.

Capital Expenditures. 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.

The following is a table of our capital expenditures, excluding acquisitions, for the year ended December 31, 2018 (in thousands):

U.S. drilling & completions	$ 163,100
Mexico appraisal & exploration	14,492
Asset management	52,452
Seismic and G&G, land, capitalized G&A and other(1)	47,637
Total capital expenditures	277,681
Plugging & abandonment	112,946
Total capital expenditures and plugging & abandonment	$ 390,627

(1) Amount excludes $29.8 million of accrued, but unpaid change of control costs for the seismic acquired as part of the Stone Combination, $3.6 million of non-cash share-based awards and $9.0 million of reimbursements related to corporate office leasehold improvements.

Off Balance Sheet Arrangements

We did not have any off balance sheet arrangements as of December 31, 2018.

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 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, 2018 (in thousands):

	2019	2020	2021	2022	Thereafter	Total[4]
Long-term financing obligations:						
Debt Principal	$ 443	$ 462	$ 482	$ 662,431	$ 8,677	$ 672,495
Debt Interest	59,960	59,941	59,922	17,313	2,129	199,265
Vessel Commitments [1]	35,206	—	—	—	—	35,206
Derivative liabilities	550	—	—	—	—	550
Operating Lease Obligations	3,622	4,315	4,016	4,298	27,225	43,476
Capital lease [2]	45,000	45,000	45,000	45,000	18,750	198,750
Purchase Obligations	15,562	11,921	7,921	—	—	35,404
Mexico minimum work program	—	19,277	—	—	—	19,277
Total contractual obligations[3][4]	$160,343	$140,916	$117,341	$ 729,042	$ 56,781	$1,204,423

(1) 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 and Helix's Q4000 well intervention vessel we will utilize for certain deep water well intervention and decommissioning activities.

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

(3) Includes committed purchase orders to execute planned future drilling and completion activities. Includes seismic use agreements.

(4) This table does not include our estimated discounted liability for dismantlement, abandonment and restoration costs of oil and natural gas properties of $382.8 million as of December 31, 2018. For additional information regarding these liabilities, please see Part II, Item 8. Financial Statements and Supplementary Data — Note 4 — *Property, Plant and Equipment*.

Performance Bonds. As of December 31, 2018 and 2017, 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 $644.1 million and $287.8 million, respectively. As of December 31, 2018 and 2017, we had $14.7 million and $4.9 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 II, Item 8. Financial Statements and Supplementary Data — Note 11 — *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 that have been implemented or changed since December 31, 2017 are described in Part II, Item 8. Financial Statements and Supplementary Data — Note 2 — *Summary of Significant Accounting Policies*.

Oil and Natural Gas Properties

We follow 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, wells currently drilling and capitalized interest are initially excluded from the amortizable base. We transfer unproved property costs into the amortizable base when properties are determined to have proved reserves or when we have completed an evaluation of the unproved properties resulting in an impairment. We evaluate 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 we own a direct interest.

Our capitalized costs are limited to a ceiling based on the present value of future net revenues from proved reserves, discounted at 10%, plus the lower of cost or estimated fair value of unproved oil and natural gas properties not being amortized. Any costs in excess of the ceiling are recognized as a non-cash impairment expense on our consolidated statement of operations and an increase to accumulated depreciation, depletion and amortization on our consolidated balance sheet. The expense will 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 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. The ceiling test computation did not result in a write-down of our oil and natural gas properties during the year ended December 31, 2018, 2017 and 2016.

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 we sell or convey interests in oil and natural gas properties, we reduce our oil and natural gas reserves for the amount attributable to the sold or conveyed interest. We do 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. We treat sales proceeds on non-significant sales as reductions to the cost of our oil and natural gas properties.

We recognize transportation costs as a component of direct lease operating expense when we are the shipper of the product. Such costs during the year ended December 31, 2018, 2017 and 2016 were \$12.5 million, \$10.3 million and \$9.1 million, respectively.

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, 2018. 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

We are required to record our asset retirement obligations at fair value in the period such obligations are incurred with the associated asset retirement costs being capitalized as part of the carrying cost of the asset. Our asset retirement obligations consist of estimated costs for dismantlement, removal, site reclamation and similar activities associated with our oil and natural gas properties. The estimate of the asset retirement cost is determined, inflated to an estimated future value using a ten year average of the Consumer Price Index and discounted to present value using our credit-adjusted risk-free rate. 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.

Revenue Recognition, Imbalances and Production Handling Fees

We record 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.

Under previous accounting guidance, we used the entitlement method to account for sales and production. Under the entitlement method, revenue was recorded based on our entitled share of production with any difference recorded as an imbalance on the consolidated balance sheet. Upon the adoption of ASC 606, 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, 2018, our imbalance receivable was approximately $1.7 million and imbalance payable was approximately $2.5 million. At December 31, 2017, our imbalance receivable was approximately $2.1 million and imbalance payable was approximately $2.7 million.

Under previous accounting guidance, we presented certain reimbursements for costs from certain third parties as other revenue on the consolidated statement of operations. Upon the adoption of ASC 606, the reimbursements are presented as a reduction of direct lease operating expense on the consolidated statement of operations. The impact of the reclassification for the year ended December 31, 2018 was immaterial.

Income Taxes

Our provision for income taxes includes both state, 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, 2018, we believe it is more likely than not that the net deferred tax asset will not be realized and therefore have recorded a valuation allowance.

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 II, Item 8. Financial Statements and Supplementary Data — Note 1 — *Formation and Basis of Presentation* to the consolidated financial statements included elsewhere in this report for our Recently Adopted Accounting Standards.

Recently Issued Accounting Standards

See Part II, Item 8. Financial Statements and Supplementary Data — Note 1 — *Formation and Basis of Presentation* to the consolidated financial statements included elsewhere in this 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 sheet 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, 2018, our average oil price realizations after the effect of derivatives increased 9% to $57.12 per Bbl from $52.46 per Bbl in the comparable 2017 period. Our average natural gas prices realizations after the effect of derivatives increased 8% during the year ended December 31, 2018 to $3.16 per Mcf from $2.93 per Mcf in the comparable 2017 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 9,146 MBbls of crude oil and 11,133 MMBtu of natural gas at December 31, 2018, with a net derivative liability position of $74.9 million. For additional information regarding our commodity derivative instruments, see Part II, Item 8. Financial Statements and Supplementary Data — Note 5 — *Financial Instruments*, included elsewhere in this 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, 2018 (in thousands):

		Oil and Natural Gas Derivatives			
		10 Percent Increase		10 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
Price impact[1]	$ 74,923	$ 30,174	$ (44,749)	$ 119,776	$ 44,853

(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 $655.3 million at December 31, 2018, net of unamortized original issue discount and deferred financing costs. Of this, $397.9 million was from our New Second Lien Notes, 7.50% Stone Senior Notes and Building Loan, which bear interest at fixed rates. The remaining $257.4 million is from 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 61% of our debt. The interest rate on our variable rate debt at December 31, 2018 was 5.46%. A 10% change in the interest rate on this variable rate debt balance at December 31, 2018 would change interest expense for the year ended December 31, 2018 by approximately $0.7 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, 2018 and 2017 and for the years ended December 31, 2018, 2017 and 2016, 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, 2018, 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, 2018 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with U.S. 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 2018 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 2019 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2018.

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 2019 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2018.

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 2019 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2018.

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 2019 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2018.

Item 14. Principal Accounting Fees and Services

The information required by this item is incorporated by reference to our Proxy Statement for the 2019 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2018.

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).
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).
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).
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	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).
4.7	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).

4.8	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).
4.9	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).
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†	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).
10.4†	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).
10.5†	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).
10.6†	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).
10.7†	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).
10.8†	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).
10.9	Voting Agreement, dated as of November 21, 2017, by and among Talos Energy LLC, Stone Energy Corporation, Franklin Advisers, Inc., as investment manager on behalf of the company stockholders listed therein and, solely for purposes of Section 11, Franklin Advisers, Inc., as investment manager on behalf of JNL/Franklin Templeton Income Fund and FT Opportunistic Destressed Fund, LTD. (incorporated by reference to Exhibit 10.1 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).
10.10	Voting Agreement, dated as of November 21, 2017, by and among Talos Energy LLC, Stone Energy Corporation and MacKay Shields LLC, in its capacity as investment manager on behalf of certain of its clients and, to the extent expressly set forth therein, in its individual capacity (incorporated by reference to Exhibit 10.2 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).

10.11	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).
10.12	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).
10.13	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).
10.14	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).
10.15†	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).
10.16†	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).
10.17†	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).
10.18†	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).
10.19†	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).
10.20†	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).
10.21†	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).
10.22†	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).
10.23†	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).
10.24†	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).
10.25†	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).
10.26†	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).

10.27†	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).
10.28†	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).
10.29†	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).
10.30†	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)
10.31†	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).
10.32†	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).
10.33†	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).
10.34*	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.
10.35*	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.
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, 2018.
99.2	Netherland, Sewell & Associates, Inc. reserve report for Talos Energy LLC as of December 31, 2017 (incorporated by reference to Exhibit 99.12 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).

99.3	Netherland, Sewell & Associates, Inc. reserve report for Talos Energy LLC as of December 31, 2016 (incorporated by reference to Exhibit 99.12 to Talos Energy Inc.'s Registration Statement on Form S-4 (File No. 333-222341) filed with the SEC on December 29, 2017).
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase 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(b)(2) 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 13, 2019	By:	/s/ MICHAEL L. HARDING II
			Michael L. Harding II Executive Vice President, Chief Financial Officer and Chief Accounting Officer

POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Timothy S. Duncan and Michael L. Harding II, 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 13, 2019
/s/ Michael L. Harding II Michael L. Harding II	Chief Financial Officer, Chief Accounting Officer (Principal Financial Officer, Principal Accounting Officer)	March 13, 2019
/s/ Rajen Mahagaokar Rajen Mahagaokar	Director	March 13, 2019
/s/ James M. Trimble James M. Trimble	Director	March 13, 2019
/s/ Olivia C. Wassenaar Olivia C. Wassenaar	Director	March 13, 2019
/s/ Christine Hommes Christine Hommes	Director	March 13, 2019
/s/ Neal P. Goldman Neal P. Goldman	Director	March 13, 2019
/s/ Charles M. Sledge Charles M. Sledge	Director	March 13, 2019
/s/ Robert M. Tichio Robert M. Tichio	Director	March 13, 2019
/s/ John “Brad” Juneau John “Brad” Juneau	Director	March 13, 2019
/s/ Donald R. Kendall, Jr. Donald R. Kendall, Jr.	Director	March 13, 2019

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, 2018 and 2017, 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, 2018, 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, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, 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, 2018, 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 13, 2019 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.

/s/ Ernst & Young LLP

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

Houston, Texas
March 13, 2019

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, 2018, 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, 2018, 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, 2018 and 2017, 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, 2018, and the related notes (collectively referred to as the "consolidated financial statements") and our report dated March 13, 2019 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 13, 2019

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

	Year Ended December 31, 2018	Year Ended December 31, 2017
ASSETS		
Current assets:		
Cash and cash equivalents	$ 139,914	$ 32,191
Restricted cash	1,248	1,242
Accounts receivable		
Trade, net	103,025	62,871
Joint interest, net	20,244	13,613
Other	19,686	12,486
Assets from price risk management activities	75,473	1,563
Prepaid assets	38,911	17,931
Inventory	—	840
Income tax receivable	10,701	—
Other current assets	7,644	2,148
Total current assets	416,846	144,885
Property and equipment:		
Proved properties	3,629,430	2,440,811
Unproved properties, not subject to amortization	108,209	72,002
Other property and equipment	33,191	8,857
Total property and equipment	3,770,830	2,521,670
Accumulated depreciation, depletion and amortization	(1,719,609)	(1,430,890)
Total property and equipment, net	2,051,221	1,090,780
Other long-term assets:		
Assets from price risk management activities	—	345
Other well equipment	9,224	2,577
Other assets	2,695	706
Total assets	$ 2,479,986	$ 1,239,293
LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)		
Current liabilities:		
Accounts payable	$ 51,019	$ 72,681
Accrued liabilities	188,650	87,973
Accrued royalties	38,520	24,208
Current portion of long-term debt	443	24,977
Current portion of asset retirement obligations	68,965	39,741
Liabilities from price risk management activities	550	49,957
Accrued interest payable	10,200	8,742
Other current liabilities	22,071	15,188
Total current liabilities	380,418	323,467
Long-term debt, net of discount and deferred financing costs	654,861	672,581
Asset retirement obligations	313,852	174,992
Liabilities from price risk management activities	—	18,781
Other long-term liabilities	123,359	103,559
Total liabilities	1,472,490	1,293,380
Commitments and contingencies (Note 11)		
Stockholders' Equity:		
Preferred stock, $0.01 par value; 30,000,000 shares authorized and no shares issued or outstanding as of December 31, 2018 and December 31, 2017	—	—
Common stock $0.01 par value; 270,000,000 shares authorized; 54,155,768 and 31,244,085 shares issued and outstanding as of December 31, 2018 and December 31, 2017, respectively	542	312
Additional paid-in capital	1,334,090	493,952
Accumulated deficit	(327,136)	(548,351)
Total stockholders' equity (deficit)	1,007,496	(54,087)
Total liabilities and stockholders' equity	$ 2,479,986	$ 1,239,293

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

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

	Year Ended December 31,		
	2018	2017	2016
Revenues:			
Oil revenue	$ 781,815	$ 344,781	$ 197,583
Natural gas revenue	73,610	48,886	42,705
NGL revenue	35,863	16,658	9,532
Other	—	2,503	8,934
Total revenue	891,288	412,828	258,754
Operating expenses:			
Direct lease operating expense	145,988	109,180	124,360
Insurance	15,342	10,743	13,101
Production taxes	1,989	1,460	1,958
Total lease operating expense	163,319	121,383	139,419
Workover and maintenance expense	64,961	32,825	24,810
Depreciation, depletion and amortization	288,719	157,352	124,689
Accretion expense	35,344	19,295	21,829
General and administrative expense	85,816	36,673	28,686
Total operating expenses	638,159	367,528	339,433
Operating income (loss)	253,129	45,300	(80,679)
Interest expense	(90,114)	(80,934)	(70,415)
Price risk management activities income (expense)	60,435	(27,563)	(57,398)
Other income	1,012	329	405
Net income (loss) before income taxes	224,462	(62,868)	(208,087)
Income tax expense	(2,922)	—	—
Net income (loss)	$ 221,540	$ (62,868)	$ (208,087)
Net income (loss) per common share:			
Basic	$ 4.81	$ (2.01)	$ (7.99)
Diluted	$ 4.81	$ (2.01)	$ (7.99)
Weighted average common shares outstanding:			
Basic	46,058	31,244	26,036
Diluted	46,061	31,244	26,036

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)

	Common Stock	Additional Paid-In Capital	Retained Earnings (Accumulated Deficit)	Total Stockholders' Equity (Deficit)
Balance at January 1, 2016	$ 258	$ 398,033	$ (277,396)	$ 120,895
Contributions from Sponsors, net	54	91,837	—	91,891
Equity based compensation	—	2,287	—	2,287
Net loss	—	—	(208,087)	(208,087)
Balance at December 31, 2016	312	492,157	(485,483)	6,986
Equity based compensation	—	1,795	—	1,795
Net loss	—	—	(62,868)	(62,868)
Balance at December 31, 2017	312	493,952	(548,351)	(54,087)
Cumulative effect adjustment (Note 1)	—	—	(325)	(325)
Sponsor Debt Exchange	29	101,971	—	102,000
Stone Combination	201	731,763	—	731,964
Equity based compensation	—	6,404	—	6,404
Net income	—	—	221,540	221,540
Balance at December 31, 2018	$ 542	$ 1,334,090	$ (327,136)	$ 1,007,496

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, 2018	2017	2016
Cash flows from operating activities:			
Net income (loss)	$ 221,540	$ (62,868)	$ (208,087)
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Depreciation, depletion, amortization and accretion expense	324,063	176,647	146,518
Impairment	244	260	218
Amortization of deferred financing costs and original issue discount	4,253	2,383	5,996
Equity based compensation, net of amounts capitalized	2,893	875	1,083
Price risk management activities (income) expense	(60,435)	27,563	57,398
Net cash received (paid) on settled derivative instruments	(111,147)	23,834	172,182
Settlement of asset retirement obligations	(112,946)	(32,573)	(23,689)
Changes in operating assets and liabilities:			
Accounts receivable	(786)	(9,132)	(20,096)
Other current assets	(2,624)	(4,441)	(3,040)
Accounts payable	(48,825)	2,409	(68,042)
Other current liabilities	32,044	46,364	51,240
Other non-current assets and liabilities, net	15,171	4,732	4,442
Net cash provided by operating activities	263,445	176,053	116,123
Cash flows from investing activities:			
Exploration, development and other capital expenditures	(240,914)	(155,177)	(113,032)
Cash (paid) received for acquisitions, net of cash acquired	278,409	(2,464)	(85,886)
Net cash provided by (used in) investing activities	37,495	(157,641)	(198,918)
Cash flows from financing activities:			
Redemption of Senior Notes and other long-term debt	(25,257)	(1,000)	—
Proceeds from Bank Credit Facility	319,000	10,000	15,000
Repayment of Bank Credit Facility	(54,000)	—	—
Repayment of LLC Bank Credit Facility	(403,000)	(15,000)	(10,000)
Deferred financing costs	(17,002)	—	—
Payments of capital lease	(12,952)	(12,412)	(5,267)
Contributions from Sponsors	—	—	93,750
Distributions to Sponsors	—	—	(1,859)
Net cash provided by (used in) financing activities	(193,211)	(18,412)	91,624
Net increase (decrease) in cash, cash equivalents and restricted cash	107,729	—	8,829
Cash, cash equivalents and restricted cash:			
Balance, beginning of period	33,433	33,433	24,604
Balance, end of period	$ 141,162	$ 33,433	$ 33,433
Supplemental Non-Cash Transactions:			
Capital expenditures included in accounts payable and accrued liabilities	$ 100,664	$ 40,626	$ 13,832
Supplemental Cash Flow Information:			
Interest paid, net of amounts capitalized	$ 53,476	$ 47,994	$ 55,254

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

TALOS ENERGY INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2018

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 with operations in the United States ("U.S.") Gulf of Mexico and offshore Mexico. The Company's focus in the U.S. Gulf of Mexico is the acquisition of deep water assets with existing infrastructure and the exploration, exploitation and development of such assets in key geological trends. Offshore Mexico provides high impact exploration opportunities in an oil rich emerging basin. The Company uses access to an extensive seismic database and its deep technical expertise to identify, acquire and exploit attractive assets with robust economic profiles.

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 "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, 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 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 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% Senior Secured Notes") and (iii) Franklin Noteholders and MacKay Noteholders exchanged their 7.50% Senior Secured Notes due 2022 issued by Stone ("7.50% Stone Senior Notes") for $137.4 million aggregate principal amount of 11.00% Senior Secured Notes.

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

The Company has one reportable segment, which is the exploration and production of oil and natural gas. 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

Revenue Recognition

On January 1, 2018, the Company adopted Accounting Standards Codification ("ASC") 606, *Revenue from Contracts with Customers* using the modified retrospective approach. ASC 606 supersedes the revenue recognition requirements in Topic 615, *Revenue Recognition*, and industry-specific guidance in Subtopic 932-605, *Extractive Activities – Oil and Gas – Revenue Recognition.* The new standard includes a five-step revenue recognition model to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the Company expects to be entitled in exchange for these goods and services.

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 applied the practical expedient in ASC 606 exempting the disclosure of the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. 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. Under previous accounting guidance, the Company used the entitlement method to account for sales and production. Under the entitlement method, revenue was recorded based on the Company's entitled share of production with any difference recorded as an imbalance on the consolidated balance sheet. Upon the adoption of ASC 606, 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 stockholders' deficit on the date of adoption.

Production Handling Fees. Under previous accounting guidance, the Company presented certain reimbursements for costs from certain third parties as other revenue on the consolidated statement of operations. Upon the adoption of ASC 606, the reimbursements are presented as a reduction of direct lease operating expense on the consolidated statement of operations. The impact of the reclassification for the year ended December 31, 2018 was immaterial.

Recently Issued Accounting Standards

Leases. In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842).* This ASU supersedes the lease requirements in Topic 840, *Leases*, and requires that a lessee recognize a right-of-use asset and lease liability for leases that do not meet the definition of a short-term lease. The right-of-use asset and lease liability are to be measured on the balance sheet at the present value of the lease payments. For income statement purposes, ASU 2016-02 retains a dual model requiring leases to be classified as either operating or finance within the Company's consolidated statements of operations. Lease costs for operating leases are recognized as a single lease cost, calculated so that the cost of the lease is allocated over the lease term on a straight-line basis. For finance leases, interest expense is recognized on the lease liability separately from amortization of the right-to-use asset. ASU 2016-02 does not apply to leases for oil and natural gas properties, but does apply to equipment used to explore and develop oil and natural gas reserves. This ASU is effective for fiscal years beginning after December 15, 2018, including the first quarter of 2019. The Company will adopt this standard using the modified retrospective method applied to all leases that exist on January 1, 2019. Talos made certain elections allowing the Company not to reassess contracts that commenced prior to adoption and to not recognize right-of-use assets or lease liabilities for short-term leases. Upon adoption, the Company expects the right-to-use asset and lease liability reported on the consolidated balance sheet to be material. The Company is finalizing the implementation of the changes to business processes, systems and controls to support accounting and disclosure requirements of this ASU.

Note 2 — Summary of Significant Accounting Policies

Below are the Company's 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 $8.7 million at December 31, 2018 and $5.9 million at December 31, 2017. The Company establishes provisions for losses on accounts receivable with other parties if it believes that it will not collect all or part of the outstanding balance. On a quarterly basis, the Company reviews collectability and establishes or adjusts the Company's allowance as necessary using the specific identification method.

Prepaid Assets

Prepaid assets primarily represent deposits with the Office of Natural Resources Revenue ("ONRR"). The deposits are the Company's estimated ONRR royalties payable within thirty days of the production rate. On a monthly basis the Company adjusts the deposit based on actual royalty payments remitted to the ONRR.

Revenue Recognition

Upon the adoption of ASC 606, revenues are recorded based from the sale of oil, natural gas and NGL quantities sold to purchasers. See Note 1 — *Formation and Basis of Presentation* for additional information.

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. In August 2016, the Company entered into a capital lease for the use of the Helix Producer I ("HP-I"), a dynamically positioned floating production facility that interconnects with the Phoenix Field through a production buoy, and recorded a $124.3 million capital lease asset. Since the HP-I is utilized in the Company's oil and natural gas development activities, the asset is included within proved property and subject to the ceiling test calculation described below. Due to the inclusion within proved properties, the HP-I is depleted as part of the full cost pool. See Note 11 — *Commitments and Contingencies* for additional information.

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'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 impairment expense on the consolidated statement 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 utilize 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. The ceiling test computation did not result in a write-down of the Company's oil and natural gas properties during the years ended December 31, 2018, 2017 and 2016.

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.

The Company recognizes transportation costs as a component of direct lease operating expense when it is the shipper of the product. Such costs were $12.5 million, $10.3 million and $9.1 million in the years ended December 31, 2018, 2017 and 2016, respectively.

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 $0.2 million, $0.3 million, $0.2 million of impairment to adjust inventory to net realizable value, which was expensed and reflected in workover/maintenance expense, during the years ended December 31, 2018, 2017 and 2016, 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 is required to record its asset retirement obligations at fair value in the period such obligations are incurred with the associated asset retirement costs being capitalized as part of the carrying cost of the asset. The Company's asset retirement obligations consist of estimated costs for dismantlement, removal, site reclamation and similar activities associated with the Company's oil and natural gas properties. The estimate of the asset retirement cost is determined, inflated to an estimated future value using a ten year average of the Consumer Price Index and discounted to present value using the Company's credit-adjusted risk-free rate. 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.

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.

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, respectively.

Earnings 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 9 — *Earnings 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 2018, 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 statement of operations, net of amounts capitalized to oil and gas properties. See Note 7 — *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, restricted cash, accounts receivable and commodity derivatives, the Company is subject to concentrated financial instruments credit risk.

Cash and cash equivalents and restricted cash 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, the majority 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 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,		
	2018	2017	2016
Shell Trading (US) Company	65%	80%	68%
Phillips 66	18%	**	**
Chevron U.S.A Inc.	**	**	14%

**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

Business Combination

Combination Between Talos Energy LLC and Stone Energy Corporation

The Stone Combination qualified as a business combination and was 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 sheet at their fair values as of the acquisition date, May 10, 2018. 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.

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 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

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 statement 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% Senior Secured Notes reflected as a debt discount reducing long-term debt on the consolidated balance sheet 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 sheet.

While the Company has substantially completed the determination of the fair values of the assets acquired and liabilities assumed, the Company is still finalizing the fair value analysis related to oil and natural gas properties acquired by Stone prior to Closing. The Company anticipates finalizing the determination of the fair values by March 31, 2019.

During the third and fourth quarters of 2018, certain adjustments were recorded to reflect new information obtained subsequent to recording the preliminary allocation of the purchase price. Income tax receivables decreased by $5.5 million, trade receivables increased by $1.0 million, other long-term liabilities increased by $2.7 million and unproved properties increased by $7.2 million. Had these adjustments been recorded as of the acquisition date, May 10, 2018, there would have been no corresponding impact to net income subsequent to the acquisition. These adjustments are reflected in the preliminary purchase price allocation table below.

The following table presents the preliminary 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)]	$	372,760
Property and equipment		883,490
Other long-term assets		18,928
Current liabilities		(130,062)
Long-term debt		(235,416)
Other long-term liabilities		(177,736)
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.

Revenue and net income attributable to the assets acquired in the Stone Combination during the year of December 31, 2018 was $332.9 million $148.5 million, respectively.

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 years ended December 31, 2018 and 2017 as if the Stone Combination had occurred on January 1, 2017. 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, 2017, nor is such information indicative of any expected future results of operations.

	Year Ended December 31,			
		2018		2017
Revenue	$	1,013,184		712,648
Net income (loss)	$	274,577		(100,980)
Basic and diluted net income (loss) per common share	$	5.07	$	(1.86)

Material, non-recurring adjustments included in pro forma net income (loss) above consist of historical Stone results adjusted to exclude a divestiture of oil and natural gas properties during 2017.

Asset Acquisitions

Each of the acquisitions below qualified as an asset acquisition that requires, among other items, that the cost of the assets acquired and liabilities assumed to be recognized on the balance sheet 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 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, 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 all of Whistler's oil and natural gas assets located in Green Canyon Block 18, Green Canyon Block 69 and Ewing Bank Block 988, including a fixed production platform on Green Canyon Block 18. The Company also assumed the associated asset retirement obligations. The Company refers to the acquisition of all the issued and outstanding membership interests as the "Whistler 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 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.

Acquisition of Additional Working Interest in the Phoenix Field

On December 20, 2016, the Company purchased an additional 15% working interest in the Phoenix Field from Sojitz Energy Venture Inc. ("Sojitz") for approximately $85.8 million in cash and the assumption of certain asset retirement obligations, subject to customary post-closing adjustments. The purchase price was funded by a $93.8 million ($91.9 million, net of $1.9 million of transaction fees) contribution from the Sponsors. Additionally, the Company entered into a contingent consideration arrangement in the form of an earn-out equal to 5% of the acquired property's monthly net profit if its realized oil price is greater than $65.00 per Bbl in a given month. The maximum payout under the earn-out is $10.0 million and it has an indefinite life pursuant to the purchase and sale agreement. The Company refers to the acquisition of assets from Sojitz as the "Sojitz Acquisition."

Through December 31, 2017, the Company recorded $2.5 million in post-closing adjustments related to activity between the effective date and closing date of the acquisition. The following table presents the allocation of the purchase price (inclusive of post-closing adjustments) to the assets acquired and liabilities assumed, based on their relative fair values, on December 20, 2016 (in thousands):

Proved properties	$	77,967
Unproved properties, not subject to amortization		11,133
Other short and long-term assets		2,380
Asset retirement obligations		(3,242)
Allocated purchase price	$	88,238

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. In August 2016, the Company entered into a capital lease for the use of the HP-I and recorded a $124.3 million capital lease asset. Since the HP-I is utilized in its oil and natural gas development activities, the asset is included within proved property, subject to the ceiling test calculation described below, and is depleted as part of the full cost pool.

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 2018, 2017 and 2016, the Company's ceiling test computations did not result in a write-down of its U.S. oil and natural gas properties. At December 31, 2018, its ceiling test computation was based on SEC pricing of $69.42 per Bbl of oil, $3.08 per Mcf of natural gas and $29.50 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, costs associated with certain exploratory wells in progress and capitalized interest. Unproved properties also include costs associated with the two blocks (Block 2 and Block 7) awarded on September 4, 2015 to the Company together with Sierra Oil & Gas S. de R.L de C.V. ("Sierra") and Premier Oil Plc ("Premier"), the ("Consortium"), located in the shallow waters off the coast of Mexico's Veracruz and Tabasco states, by the National Hydrocarbons Commission ("CNH"), Mexico's upstream regulator.

In September 2018, the Company entered into a transaction (the "Hokchi Cross Assignment") with Hokchi Energy, S.A. de C.V. ("Hokchi"), a subsidiary of Pan American Energy ("PAE"), to cross assign 25% participation interests ("PIs") in Block 2 and Block 31. The Company's assignment of a 25% PI in Block 2 to Hokchi closed on December 21, 2018, and Hokchi has assumed operator responsibilities with respect to Block 2. Hokchi's assignment of Block 31 to the Company will be completed upon final approval by the CNH subsequent to December 31, 2018. In addition, Premier exercised its option to reduce its PI in Block 2 to zero and assign a 5% PI to each of Sierra and the Company. Such assignment is also subject to CNH's approval which had not occurred as of December 31, 2018. Upon completion of the Hokchi Cross Assignment and Premier's option exercise, the Company will own a 25% PI in each of Block 2 and Block 31, and Hokchi will be the operator of both blocks.

The following table sets forth a summary of the Company's oil and natural gas property costs not being amortized at December 31, 2018, by the year in which such costs were incurred (in thousands):

		Year Ended December 31,			
	Total	**2018**	**2017**	**2016**	**2015 and Prior**
Acquisition United States	$ 49,777	$ 40,657	$ —	$ 2,244	$ 6,876
Exploration United States	13,327	8,391	3,188	92	1,656
Total United States unproved properties, not subject to amortization	$ 63,104	$ 49,048	$ 3,188	$ 2,336	$ 8,532
Exploration Mexico	45,105	14,362	23,332	6,110	1,301
Total Mexico unproved properties, not subject to amortization	$ 45,105	$ 14,362	$ 23,332	$ 6,110	$ 1,301
Total unproved properties, not subject to amortization	$ 108,209	$ 63,410	$ 26,520	$ 8,446	$ 9,833

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 expects this process to occur over the next five years.

Capitalized Overhead. General and administrative expense in the Company's financial statements is reflected net of capitalized overhead. The Company capitalizes overhead costs that are directly related to exploration, acquisition and development activities. Capitalized overhead for the years ended December 31, 2018, 2017 and 2016 was $21.9 million, $13.7 million and $12.5 million, respectively.

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.

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, 2018 and 2017 were as follows (in thousands):

	Year Ended December 31, 2018	Year Ended December 31, 2017
Asset retirement obligations at January 1	$ 214,733	$ 220,049
Fair value of asset retirement obligations acquired[(1)]	244,766	699
Obligations settled	(112,946)	(32,573)
Accretion expense	35,344	19,295
Obligations incurred	358	4,213
Changes in estimate	562	3,050
Asset retirement obligations at December 31	$ 382,817	$ 214,733
Less: Current portion	(68,965)	(39,741)
Long-term portion	$ 313,852	$ 174,992

(1) Includes $220.6 million and $23.9 million of asset retirement obligations assumed in the Stone Combination and the Whistler Acquisition, respectively.

Note 5 — Financial Instruments

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

	December 31, 2018		December 31, 2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
11.00% Second-Priority Senior Secured Notes – due April 2022[(1)]	$ 381,229	$ 362,168	$ —	$ —
7.50% Senior Secured Notes – due May 2022	$ 6,060	$ 5,151	$ —	$ —
Bank Credit Facility – due May 2022[(1)]	$ 257,448	$ 265,000	$ —	$ —
11.00% Bridge Loans – due April 2022[(1)]	$ —	$ —	$ 169,838	$ 172,023
9.75% Senior Notes – due July 2022[(1)]	$ —	$ —	$ 100,681	$ 102,000
9.75% Senior Notes – due February 2018	$ —	$ —	$ 24,977	$ 24,977
LLC Bank Credit Facility - due February 2019[(1)]	$ —	$ —	$ 402,062	$ 403,000
Oil and Natural Gas Derivatives	$ 74,923	$ 74,923	$ (66,830)	$ (66,830)

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

As of December 31, 2018 and 2017, the carrying amounts of cash and cash equivalents, accounts receivable, restricted cash 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 $390.9 million aggregate principal amount of 11.00% Senior Secured Notes is reported on the consolidated balance sheet at its carrying value, net of original issue discount and deferred financing costs, see Note 6 — *Debt*. The fair value of the 11.00% Senior Secured Notes is estimated (representing a Level 1 fair value measurement) using quoted secondary market trading prices.

7.50% Senior Secured Notes – due May 2022. The $6.1 million aggregate principal amount of 7.50% Stone Senior Notes is reported on the consolidated balance sheet as of December 31, 2018 at its carrying value, see Note 6 — *Debt*. The fair value of the 7.50% Stone Senior Notes is estimated (representing a Level 1 fair value measurement) using quoted secondary market trading prices.

Bank Credit Facility – due May 2022. On May 10, 2018, in connection with the Stone Combination, the Talos Energy LLC senior reserve-based revolving credit facility ("LLC Bank Credit Facility") was repaid and terminated, and the Company executed a new Bank Credit Facility with an initial borrowing base of $600.0 million (the "Bank Credit Facility"). The LLC Bank Credit Facility was repaid with borrowings from the Bank Credit Facility and cash acquired in the Stone Combination. The Company's Bank Credit Facility is reported on the consolidated balance sheet as of December 31, 2018 at its carrying value net of deferred financing costs, see Note 6 — *Debt*. The fair value of the Bank Credit Facility is estimated based on the outstanding borrowings under the Company's 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 sheet 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,		
	2018	2017	2016
Price risk management activities income (expense)[1]	$ 60,435	$ (27,563)	$ (57,398)

(1) The Company paid cash settlements of $111.1 million, and received cash settlements of $23.8 million and $172.2 million for the years ended December 31, 2018, 2017 and 2016, respectively.

The following table reflects the contracted volumes and weighted average prices the Company will receive under its derivative contracts as of December 31, 2018:

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 2019 – December 2019	Swap	25,059	$ 55.39	$ —	$ —
Natural Gas – Henry Hub NYMEX:		*(MMBtu)*	*(per MMBtu)*	*(per MMBtu)*	*(per MMBtu)*
January 2019 – December 2019	Collar	8,630	$ —	$ 3.00	$ 3.95
January 2019 – December 2019	Swaps	21,872	$ 2.90	$ —	$ —

Subsequent event. The following table reflects the contracted volumes and weighted average prices the Company will receive under its derivative contracts entered into subsequent to December 31, 2018, which are not reflected in the table above:

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)*
April 2019 – December 2019	Swap	3,444	$ 56.94	$ —	$ —
January 2020 - December 2020	Swap	3,746	$ 57.07	$ —	$ —
January 2020 - December 2020	Collar	3,000	$ 55.00	$ 55.00	$ 60.64
Natural Gas – Henry Hub NYMEX:		*(MMBtu)*	*(per MMBtu)*	*(per MMBtu)*	*(per MMBtu)*
April 2019 – December 2019	Swap	19,418	$ 2.89	$ —	$ —

The following tables provide additional information related to financial instruments measured at fair value on a recurring basis (in thousands):

	December 31, 2018			
	Level 1	Level 2	Level 3	Total
Assets:				
Oil and natural gas swaps and costless collars	$ —	$ 75,473	$ —	$ 75,473
Liabilities:				
Oil and natural gas swaps and costless collars	—	(550)	—	(550)
Total net asset	$ —	$ 74,923	$ —	$ 74,923

	December 31, 2017			
	Level 1	Level 2	Level 3	Total
Assets:				
Oil and natural gas swaps and costless collars	$ —	$ 1,908	$ —	$ 1,908
Liabilities:				
Oil and natural gas swaps and costless collars	—	(68,738)	—	(68,738)
Total net liability	$ —	$ (66,830)	$ —	$ (66,830)

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 present 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, 2018 and 2017 (in thousands):

	December 31, 2018		December 31, 2017	
	Assets	Liabilities	Assets	Liabilities
Oil and natural gas derivatives:				
Current	$ 75,473	$ 550	$ 1,563	$ 49,957
Non-current	—	—	345	18,781
Total	$ 75,473	$ 550	$ 1,908	$ 68,738

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, 2018 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 seven 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 6 — 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):

Description	December 31, 2018	December 31, 2017
11.00% Second-Priority Senior Secured Notes – due April 2022	$ 390,868	$ —
7.50% Senior Secured Notes – due May 2022	6,060	—
Bank Credit Facility – due May 2022	265,000	—
4.20% Building Loan – due November 2030	10,567	—
11.00% Bridge Loans – due April 2022	—	172,023
9.75% Senior Notes – due July 2022	—	102,000
9.75% Senior Notes – due February 2018	—	24,977
LLC Bank Credit Facility – due February 2019	—	403,000
Total debt, before discount and deferred financing cost	672,495	702,000
Discount and deferred financing cost	(17,191)	(4,442)
Total debt, net of discount and deferred financing costs	655,304	697,558
Less: Current portion of long-term debt	(443)	(24,977)
Long-term debt, net of discount and deferred financing costs	$ 654,861	$ 672,581

In connection with the Stone Combination, the Company consummated the Transactions, pursuant to which (i) the Apollo Funds and Riverstone Funds contributed $102.0 million in aggregate principal amount of 9.75% Senior Notes to the Company in exchange for Common Stock; (ii) the holders of 11.00% Bridge Loans exchanged such 11.00% Bridge Loans for $172.0 million aggregate principal amount of 11.00% Senior Secured Notes and (iii) Franklin Noteholders and MacKay Noteholders exchanged their 7.50% Stone Senior Notes for $137.4 million aggregate principal amount of 11.00% Senior Secured Notes. An additional $81.5 million of 7.50% Stone Senior Notes held by non-affiliates were also exchanged for 11.00% Senior Secured Notes pursuant to an exchange offer and consent solicitation in connection with the Stone Combination.

The exchanges to 11.00% Senior Secured Notes were accounted for as a debt modification. Under a debt modification, a new effective interest rate that equates the revised cash flows to the carrying amount of the 11.00% Senior Secured Notes is computed and applied prospectively. Costs incurred with third parties directly related to the modification are expensed as incurred. The Company incurred approximately $4.3 million of transaction fees related to the modification which were expensed and reflected in general and administrative expense on the consolidated statements of operations during the year ended December 31, 2018. The Company also paid $9.3 million in work fees to holders of the 11.00% Senior Secured Notes, which are reflected as debt discount reducing long-term debt on the consolidated balance sheet.

11.00% Second-Priority Senior Secured Notes – due April 2022. The 11.00% Senior Secured 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% Senior Secured Notes mature April 3, 2022 and have interest payable semi-annually each April 15 and October 15. Prior to May 10, 2019, the Company may, at its option, redeem all or a portion of the 11.00% Senior Secured Notes at 100% of the principal amount plus accrued and unpaid interest and a make-whole premium. Thereafter, the Company may redeem all or a portion of the 11.00% Senior Secured Notes at redemption prices decreasing annually from 105.5% to 100.0% plus accrued and unpaid interest.

The indenture governing the 11.00% Senior Secured 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% Senior Secured Notes contain customary quarterly and annual reporting, financial and administrative covenants. The Company was in compliance with all debt covenants at December 31, 2018.

7.50% Senior Secured Notes – due May 2022. The 7.50% Stone Senior Notes represent the remaining $6.1 million of long-term debt assumed in the Stone Combination that were not exchanged for 11.00% Senior Secured 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% Stone Senior Notes have been removed and collateral securing the 7.50% Stone Senior Notes has been released. The 7.50% Stone Senior Notes mature May 31, 2022 and have interest payable semi-annually each May 31 and November 30. Prior to May 31, 2020, the Company may, at its option, redeem all or a portion of the 7.50% Stone Senior Notes at 100% of the principal amount plus accrued and unpaid interest and a make-whole premium. Thereafter, the Company may redeem all or a portion of the 7.50% Stone Senior Notes at redemption prices decreasing annually from 105.625% to 100.0% plus accrued and unpaid interest.

Bank Credit Facility – due May 2022. Talos Production LLC, a subsidiary of the Company, executed the Bank Credit Facility in conjunction with the Stone Combination with a syndicate of financial institutions, with an initial borrowing base of $600.0 million. The Bank Credit Facility is currently scheduled to mature on May 10, 2022.

The Bank Credit Facility bears interest based on the borrowing base usage, at the applicable London InterBank Offered Rate, plus applicable margins ranging from 2.75% to 3.75% or an alternate base rate, based on the federal funds effective rate plus applicable margins ranging from 1.75% to 2.75%. In addition, the Company is obligated to pay a commitment fee of 0.50% on the unfunded portion of the commitments under the Bank Credit Facility. 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 each quarter. The Company must also maintain a current ratio no less than 1.00 to 1.00 each quarter. According to the Bank Credit Facility, undrawn 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 its proved undeveloped reserves. The borrowing base is redetermined by the lenders at least semi-annually during the second quarter and fourth quarter. On November 16, 2018 the borrowing base was increased from $600.0 million to $850.0 million. However, the Company elected to maintain the $600.0 million commitment based upon its current liquidity needs. The next redetermination is scheduled for April 2019.

As of December 31, 2018, commitments under the Company's borrowing base was set at $600.0 million, of which no more than $200.0 million 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, 2018. As of December 31, 2018, the Bank Credit Facility had approximately $320.3 million of undrawn commitments (taking into account $14.7 million letters of credit and $265.0 million drawn from the Bank Credit Facility).

Building Loan – due November 2030. In connection with the Stone Combination, the Company assumed Stone's 4.20% term loan maturing on November 20, 2030 (the "Building Loan"). The Building Loan bears interest at a rate of 4.20% per annum and is to be repaid in 180 equal monthly installments of approximately $0.1 million. As of December 31, 2018, the outstanding balance under the Building Loan totaled $10.6 million. The Building Loan is collateralized by the Company's two office buildings in Lafayette, Louisiana. Under the financial covenants of the Building Loan, the Company must maintain a ratio of EBITDA to Net Interest Expense of not less than 2.00 to 1.00. In addition, the Building Loan contains certain customary restrictions or requirements with respect to change of control and reporting responsibilities. The Company was in compliance with all covenants under the Building Loan as of December 31, 2018.

9.75% Senior Notes – due February 2018. The 2018 Senior Notes were issued pursuant to an indenture dated February 6, 2013 among the Talos Issuers, the subsidiaries, as issuers, the subsidiary guarantors party thereto and the trustee. On February 15, 2018, the Talos Issuers redeemed the remaining $25.0 million principal amount of the 9.75% Senior Notes at par.

Subsequent Event. On January 22, 2019, the Company borrowed $35.0 million from the Bank Credit Facility to fund 2019 acquisition activities, see Note 15 — *Subsequent Events*.

Note 7 — Employee Benefits Plans and Share-Based Compensation

Stone Change of Control and Severance Plans

The Company maintains 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 provide 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 Closing. For the year ended December 31, 2018 the Company incurred $7.8 million of severance expense, reflected in general and administrative expense on the consolidated statement of operations. Approximately $0.3 million of such expense remained unpaid at December 31, 2018.

Talos Energy Inc. Long Term Incentive Plan

In connection with the Closing, the Company adopted the Talos Energy Inc. Long Term Incentive Plan (the "LTIP"), pursuant to which the Company may issue, subject to Board approval, grants of 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. During the year ended December 31, 2018, the Company granted 116,448 RSUs under the LTIP to employees. These RSUs had a grant date fair value of $3.9 million and vest ratably over an approximate three year period, which began on May 14, 2018, 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, 2018 was approximately $3.3 million, which is expected to be recognized over a weighted average period of 2.4 years.

Restricted Stock Units – Non-employee Directors. On May 21, 2018, the Company granted 22,963 RSUs under the LTIP to non-employee directors. These RSUs had a grant date fair value of $0.8 million and vest on May 19, 2019, 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% or 13,778 of these RSUs, and cash for the remaining 40% or 9,185 of these RSUs. The total unrecognized share-based compensation expense related to these RSUs at December 31, 2018 was approximately $0.2 million, which is expected to be recognized over a weighted average period of 0.4 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 year ended December 31, 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

Performance Share Units – Employees. During the year ended December 31, 2018, the Company granted 232,891 PSUs to employees with each PSU representing the contingent right to receive one share of Common Stock. However, the number of Common Stock shares issuable upon vesting ranges from zero to 200% of the number of PSUs granted based on the total shareholder return ("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, 2018 was approximately $9.2 million, which is expected to be recognized over a weighted average period of 2.4 years.

The following table summarizes PSU activity for the year ended December 31, 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

The grant date fair value of the PSUs, calculated using a Monte Carlo simulation, was $10.4 million. The following table summarizes the assumptions used to calculate the grant date fair value of the PSUs granted August 29, 2018 and September 28, 2018:

	August 29, 2018 Grant Date Fair Value Assumptions	September 28, 2018 Grant Date Fair Value Assumptions
Number of simulations	100,000	100,000
Expected term (in years)	2.7	2.6
Expected volatility	50.6%	47.4%
Risk-free interest rate	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 Company 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 $25.0 million in 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 sheet.

The Company's unrecognized compensation expense at December 31, 2018 is approximately $2.7 million. Of this amount, approximately $0.5 million of the unrecognized compensation expense will continue to be recognized on a straight-line basis over the remainder of the four year requisite service period. The remaining $2.2 million will be recognized upon an Aggregate Series A Payout. The weighted-average period over which the unrecognized compensation expense for the Series B Units will be recognized is 1.7 years.

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 Company 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 sheet.

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, 2018 is approximately $1.2 million. Of this amount, approximately $0.2 million of the unrecognized compensation expense will continue to be recognized on a straight-line basis over the remainder of the four year requisite service period. The remaining $1.0 million will be recognized upon the New Series A Units receiving the cumulative distribution. The weighted-average period over which the unrecognized compensation expense will be recognized is 0.8 months.

Share-based Compensation Expense, net

Share-based compensation expense associated with RSUs, PSUs and Series B Units are reflected as general administrative expense, net amounts capitalized to oil and gas properties in the consolidated statement of operations. 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 used in or provided by operating activities in the consolidated statement of cash flows.

For the year ended December 31, 2018, share-based compensation expense did not have any associated income tax benefit. The Company recognized the following share-based compensation expense, net for the following years (in thousands):

	Year Ended December 31,		
	2018	2017	2016
Restricted stock units - Employees	$ 560	$ —	$ —
Restricted stock units - Non-employee Directors	402	—	—
Performance share units	1,129	—	—
Talos Energy LLC Series B Units	666	1,795	2,287
New Talos Energy LLC Series B Units	3,752	—	—
Total share-based compensation expense	6,509	1,795	2,287
Less: amounts capitalized to oil and gas properties	(3,616)	(920)	(1,204)
Total share-based compensation expense, net	$ 2,893	$ 875	$ 1,083

Note 8 — 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 were conducted under a different legal form and are subject to foreign income taxes.

In connection with the Stone Combination, Talos Energy LLC was contributed to the Company, which is subject to federal and state income taxes. The Company is also subject to foreign income taxes. Due to the change in tax status, deferred taxes are recorded for differences in book and tax basis. The Company's differences in its book and tax basis in its assets and liabilities is primarily related to different cost recovery periods utilized for book and tax purposes for the Company's oil and natural gas properties, asset retirement obligations and net operating loss carryforwards. A valuation allowance is established to reduce deferred tax assets when it is more likely than not that some portion or all of the deferred tax asset will not be realized. The Company believes it is more likely than not that the net federal deferred tax asset will not be realized and therefore recorded a valuation allowance. Due to the valuation allowance, the tax expense resulting from the initial book and tax basis difference from the change in tax status was zero. The Company accounted for the book and tax basis difference from the Stone Combination in acquisition method accounting and recorded an estimated state deferred tax liability of $2.7 million.

As part of the Stone Combination, entities related to the Apollo Funds and Riverstone Funds contributed entities to the Company that were under common control. At December 31, 2018, the Company also estimated a net deferred tax asset related to tax loss carryforwards and differences in book and tax basis of assets. The net deferred tax asset and valuation allowance from the contribution is accounted for in stockholder's equity. The Company believes it is more likely than not that the net deferred tax asset will not be realized and therefore recorded a valuation allowance.

As a result of the Stone Combination, the Company acquired a current income tax receivable of $10.7 million primarily related to the carryback of specified liability losses.

Tax Cuts and Jobs Act. On December 22, 2017, the President signed into law Public Law No. 115-97 ("Tax Act"), an Act to provide for reconciliation pursuant to titles II and V of the concurrent resolution on the budget for fiscal year 2018. The Tax Act made broad and complex changes to the U.S. tax code. The SEC issued SAB 118, which has since been codified into ASC 740, providing guidance on the accounting for the tax effects of the Tax Act. ASC 740 provides a measurement period that should not extend beyond one year from the Tax Act enactment date to complete the accounting under ASC 740. In accordance with this pronouncement, the Company completed its assessment on certain effects of the Tax Act in the financial statements for the period ending December 31, 2018. In assessing the need for a valuation allowance on its deferred tax assets, the Company considered whether it was more likely than not that some portion or all of them will not be realized. Due to a full valuation allowance against the Company's deferred tax assets, the adjustments did not have any net impact on tax expense for 2018.

The components of income tax expense (benefit) were as follows (in thousands):

	Year Ended December 31,		
	2018	2017	2016
Current income tax expense (benefit)			
United States	$ —	$ —	$ —
Mexico	1,345	—	—
Total current income tax expense (benefit)	$ 1,345	$ —	$ —
Deferred income tax expense (benefit)			
United States	$ 1,064	$ —	$ —
Mexico	513	—	—
Total deferred income tax expense (benefit)	1,577	—	—
Total income tax expense (benefit)	$ 2,922	$ —	$ —

The reconciliation of income taxes computed at the U.S. federal statutory tax rate to the Company's income tax expense is as follows (in thousands, except percentages):

	Year Ended December 31,		
	2018	2017	2016
Income tax (benefit) at the federal statutory tax rate	$ 47,137	$ (22,004)	$ (72,830)
Earnings not subject to tax	9,980	22,004	72,830
State income taxes	11,738	—	—
Foreign income taxes	1,008	—	—
Foreign rate differential	432	—	—
Prior year taxes	417	—	—
Other adjustments	800	—	—
Change in tax status	(35,925)	—	—
Change in valuation allowance	(32,665)		
Total income tax	$ 2,922	$ —	$ —
Effective tax rate	1.30%	—%	—%

The Company's effective tax rate for the year ending December 31, 2018, differed from the federal statutory rate of 21.0% primarily due to recording a valuation allowance for its deferred tax assets. The effective tax rate for years 2017 and 2016 differed from the federal statutory rate of 35.0% because the Company was not subject to U.S. federal or state taxation as a partnership and the Company's Mexico operations did not incur a material income tax expense.

Deferred Tax Assets and Liabilities

Deferred taxes 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,	
	2018	**2017**
Deferred tax assets:		
Federal net operating loss	$ 117,546	$ —
Foreign tax loss carryforward	2,303	4,023
State net operating loss	23,542	—
Asset retirement obligations	95,546	—
Tax credits	12	—
Interest	33,867	—
Other	5,909	—
Total deferred tax assets	278,725	4,023
Valuation allowance	(94,085)	(4,007)
Total deferred tax assets, net	$ 184,640	$ 16
Deferred tax liabilities		
Oil and gas properties	166,879	—
Hedges	18,246	—
Prepaid	3,371	—
Deferred tax liabilities	188,496	—
Net deferred tax asset (liability)	$ (3,856)	$ 16

Income Tax Receivables and Payables

As of December 31, 2018, the Company recorded current income tax receivables of $10.7 million. As a result of the Stone Combination, the Company acquired the current income tax receivable primarily related to the carryback of specified liability losses. The Company has also recorded an income tax payable of $1.3 million primarily related to estimated taxes for the 2018 Mexico tax returns.

Net Operating Loss

The table below presents the details of the Company's net operating loss and tax credit carryovers as of December 31, 2018 (in thousands):

	Amount	Expiration Year
Federal net operating losses	$ 557,895	2034-2038
Foreign tax loss carryforward	$ 8,970	2025-2028
State net operating losses	$ 307,629	2019-2038

As of December, 31, 2018, the Company had U.S. federal net operating loss carryforwards ("NOLs") of approximately $557.9 million, of which $538.4 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 2034.

Valuation Allowance

During 2018, the Company recorded a valuation allowance of $94.1 million related to federal, state and foreign deferred tax assets. Deferred tax assets are recorded related to net operating losses and temporary differences between the book and tax basis of assets and liabilities expected to produce tax deductions in future periods. The realization of these assets depends on recognition of sufficient future taxable income in specific tax jurisdictions in which those temporary differences or net operating losses are deductible. In assessing the need for a valuation allowance on deferred tax assets, the Company considers whether it is more likely than not that some portion or all of them will not be realized. As of December 31, 2018, the Company had a valuation allowance related to federal, state and foreign deferred tax assets. The Company did not record a valuation allowance during 2017 for federal and state deferred tax assets as the Company was not subject to taxation as a partnership during this period.

Uncertain Tax Positions

The table below sets forth the beginning and ending balance of the total amount of unrecognized tax benefits. There are no unrecognized benefits that would impact the effective tax rate if recognized. While amounts could change in 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,	
	2018	2017
Total unrecognized tax benefits, beginning balance	$ —	$ —
Increases (decreases) in unrecognized tax benefits as a result of:		
Tax positions taken during a prior period	360	—
Tax positions taken during the current period	—	—
Settlements with taxing authorities	—	—
Lapse of applicable statute of limitations	—	—
Total unrecognized tax benefits, ending balance	$ 360	$ —

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 2015 through 2017 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, 2014 are closed.

Note 9 — Earnings Per Share

Basic earnings per common share 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 earnings per common share includes the impact of RSUs, PSUs and outstanding warrants.

As of December 31, 2018, the Company had approximately 3.5 million outstanding warrants. These warrants have an exercise price of $42.04 per share and a term of four years ending February 28, 2021. As of December 31, 2018, the Company had 138,704 and 231,542 outstanding RSUs and PSUs, respectively, which settle in shares of Common Stock.

For the year ended December 31, 2018, dilutive weighted average shares for RSUs and PSUs totaled 2,819 shares resulting in an increase to the basic weighted average common shares of 46,058,216 to arrive at diluted weighted average common shares outstanding of 46,061,035. For the year ended December 31, 2018, 419,639 weighted average antidilutive RSUs and PSUs were excluded from the computation of diluted earnings per common share. Additionally, for the year ended December 31, 2018, all outstanding warrants were considered antidilutive due to the exercise price of the warrants exceeding the average market price of Common Stock.

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. There is no impact in fiscal year 2017 and 2016 on diluted earnings per common share from the RSUs, PSUs and outstanding warrants as these instruments did not exist throughout such periods.

Note 10 — Related Party Transactions

Whistler Acquisition. On August 31, 2018, the Company acquired Whistler 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, 2018 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 the Closing Date, the Company entered into an Equity Registration Rights Agreement with each of the Apollo Funds, Riverstone Funds, Franklin and MacKay Shields relating to the registered resale of its Common Stock owned by such parties as of Closing. The Company will bear all of the expenses incurred in connection with the offer and sale, while the Apollo Funds, Riverstone Funds, Franklin and MacKay Shields are responsible for paying underwriting fees, discounts and commissions or similar charges. Fees incurred by the Company in conjunction with the Equity Registration Rights Agreement were $1.8 million for the year ended December 31, 2018.

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 year ended December 31, 2018, 2017 and 2016, the Company incurred fees of approximately $4.4 million, $4.0 million and $0.7 million, respectively, of which $1.1 million, $4.0 million and $0.1 million were payable at each respective balance sheet date for legal services performed by Vinson & Elkins L.L.P.

Contributions and Distributions. During the years ended December 31, 2018 and 2017, the Company did not receive any cash contributions or make any distributions to Apollo Funds and Riverstone Funds. During the year ended December 31, 2016, the Company received a $93.8 million ($91.9 million net of $1.9 million of transaction fees) capital contribution from Apollo Funds and Riverstone Funds primarily to fund the Sojitz Acquisition. See Note 3 — *Acquisitions* for further details.

Transaction Fee Agreement. As part of the agreements with Apollo Funds and Riverstone Funds, the Company paid a transaction fee equal to 2% of capital contributions made by Apollo Funds and Riverstone Funds. For the years ended December 31, 2018 and 2017, there were no capital contributions and thus the Company did not incur or pay transaction fees related to capital contributions. For the year ended December 31, 2016 the Company incurred fees totaling $1.9 million related to the capital contributions received from Apollo Funds and Riverstone Funds. In connection with the Stone Combination, the Transaction Fee Agreement was terminated on May 10, 2018.

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 year ended December 31, 2018, 2017 and 2016, the Company incurred approximately $0.5 million, $0.5 million 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. The Company paid $9.3 million in work fees to holders of the 11.00% Bridge Loans and 7.50% Stone Senior Notes to exchange into 11.00% Senior Secured 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 11 — Commitments and Contingencies

Capital Lease

On August 2, 2016, the Company executed a seven-year lease agreement (the "Agreement"), effective June 1, 2016, with Helix for use of the HP-I to process hydrocarbons produced from the Phoenix Field. Under the terms of the Agreement, the Company paid Helix a $49.0 annual fixed demand charge plus a potential $0.5 million quarterly incentive payment if certain uptime rates were achieved. Thereafter the Company will pay a $45.0 annual fixed demand charge plus a potential $0.8 million quarterly incentive payment if certain uptime rates are achieved.

The Agreement with Helix is accounted for as a capital lease. The Company initially recorded both a capital lease asset and obligation of $124.3 million on its consolidated balance sheet. As of December 31, 2018, the balance of the capital lease obligation on the consolidated balance sheet is $93.6 million, of which $14.1 million is included in other current liabilities and $79.5 million is included in other long-term liabilities. As a result of the Agreement being accounted for as a capital lease, the lease payments are reflected as (i) a reduction of the capital lease obligation, (ii) interest expense and (iii) direct lease operating expense.

As of December 31, 2018, minimum lease commitments for the capital lease in future years are as follows (in thousands):

2019	$	45,000
2020		45,000
2021		45,000
2022		45,000
2023		18,750
Total minimum lease payments		198,750
Less amount represented lease operating expenses		(51,864)
Less amount represented interest		(53,218)
Present value of minimum lease payments		93,668
Less current maturities of capital lease obligations		(14,127)
Long-term capital lease obligations	$	79,541

Legal Proceedings and Other Contingencies

On January 6, 2016, Energy Resource Technology GOM, LLC ("ERT") plead guilty to two violations of the Clean Water for self-reported activities surrounding overboard discharge sampling and unpermitted discharges and two violations of Outer Continental Shelf Lands Act. On April 6, 2016, the United States District Court for the Eastern District of Louisiana accepted ERT's plea and sentenced ERT, consistent with the plea agreement, to pay a penalty of $4.2 million which ERT has paid. The Court placed ERT on probation for three years. The conditions of probation include compliance with an agreed Safety and Environmental Compliance Program. As a result of ERT's conviction for violations of the Clean Water Act, ERT was debarred and cannot enter into contracts with or receive benefits from the federal government, until the EPA reinstates ERT by certifying that ERT has corrected the conditions giving rise to the Clean Water convictions. EPA also imposed discretionary suspension and proposed debarment on Talos Production LLC, Talos Energy Offshore LLC and Talos Energy LLC as affiliates of ERT. On November 23, 2016, EPA terminated and administratively closed the suspension as to each of the three entities previously suspended. On August 29, 2017, EPA certified that the conditions giving rise to ERT's conviction were corrected, and its debarment was lifted.

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, 2018 and 2017, the Company had secured performance bonds totaling approximately $644.1 million and $287.8 million, respectively. As of December 31, 2018 and 2017, the Company had $14.7 million and $4.9 million, respectively, in letters of credit issued under its Bank Credit Facility.

The table below summarizes the Company's total minimum commitments associated with long-term, non-cancelable operating leases, vessel commitments, purchase obligations and the Mexico minimum work program as of December 31, 2018 (in thousands):

	2019	2020	2021	2022	Thereafter	Total
Vessel Commitments[(1)]	$ 35,206	$ —	$ —	$ —	$ —	$ 35,206
Committed purchase orders[(2)]	15,562	11,921	7,921	—	—	35,404
Operating lease obligations[(3)]	3,622	4,315	4,016	4,298	27,225	43,476
Mexico minimum work program	—	19,277	—	—	—	19,277
Total[(4)]	$ 54,390	$ 35,513	$ 11,937	$4,298	$ 27,225	$133,363

(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 as well as seismic use agreements the Company entered into in connection with the Stone Combination.

(3) Amounts include long-term lease payments for office space.

(4) Excludes the capital lease for the HP-I floating production facility in the Phoenix Field discussed above.

The table above includes leases for buildings, facilities and related equipment with varying expiration dates through 2029. Total rent expense, for continuing operations, included in general and administrative expense for the years ended December 31, 2018, 2017 and 2016 was $2.9 million, $2.1 million and $2.0 million, respectively.

Note 12 — Condensed Consolidating Financial Information

Talos Energy Inc. owns no operating assets and has no operations independent of its subsidiaries. Talos Production LLC and Talos Production Finance Inc. issued 11.00% Second-Priority Senior Secured Notes on May 10, 2018, which are fully and unconditionally guaranteed, jointly and severally, by Talos Energy Inc. and certain 100% owned subsidiaries on a senior unsecured basis.

The following condensed consolidating financial information presents the financial information of the Company on an unconsolidated stand-alone basis and its combined guarantor and combined non-guarantor subsidiaries as of and for the period indicated. Such financial information may not necessarily be indicative of the Company's results of operations, cash flows, or financial position had these subsidiaries operated as independent entities.

TALOS ENERGY INC.
CONSOLIDATING BALANCE SHEET
AS OF DECEMBER 31, 2018
(In thousands)

	Parent	Subsidiary Issuers	Guarantors	Non-Guarantors	Elimination	Consolidated
ASSETS						
Current assets:						
Cash and cash equivalents	$ —	$ 13,541	$ 100,801	$ 25,572	$ —	$ 139,914
Restricted cash	—	—	1,248	—	—	1,248
Accounts receivable						
Trade, net	—	—	103,025	—	—	103,025
Joint interest, net	—	—	15,870	4,374	—	20,244
Other	—	3,100	9,566	7,020	—	19,686
Assets from price risk management activities	—	75,473	—	—	—	75,473
Prepaid assets	—	1,225	37,639	47	—	38,911
Income tax receivable	—	—	10,701	—	—	10,701
Other current assets	—	—	7,644	—	—	7,644
Total current assets	—	93,339	286,494	37,013	—	416,846
Property and equipment:						
Proved properties	—	—	3,629,430	—	—	3,629,430
Unproved properties, not subject to amortization	—	—	63,104	45,105	—	108,209
Other property and equipment	—	20,670	12,440	81	—	33,191
Total property and equipment	—	20,670	3,704,974	45,186	—	3,770,830
Accumulated depreciation, depletion and amortization	—	(8,310)	(1,711,288)	(11)	—	(1,719,609)
Total property and equipment, net	—	12,360	1,993,686	45,175	—	2,051,221
Other long-term assets:						
Other well equipment inventory	—	—	9,224	—	—	9,224
Investments in subsidiaries	1,011,359	1,560,922	—	—	(2,572,281)	—
Other assets	—	364	2,258	73	—	2,695
	1,011,359	1,666,985	2,291,662	82,261	(2,572,281)	2,479,986
LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)						
Current liabilities:						
Accounts payable	144	1,242	42,736	6,897	—	51,019
Accrued liabilities	—	4,995	159,491	24,164	—	188,650
Accrued royalties	—	—	38,520	—	—	38,520
Current portion of long-term debt	—	—	443	—	—	443
Current portion of asset retirement obligations	—	—	68,965	—	—	68,965
Liabilities from price risk management activities		550	—	—	—	550
Accrued interest payable	—	10,162	38	—	—	10,200
Other current liabilities	—	—	22,071	—	—	22,071
Total current liabilities	144	16,949	332,264	31,061	—	380,418
Long-term debt, net of discount and deferred financing costs	—	638,677	16,184	—	—	654,861
Asset retirement obligations	—	—	313,852	—	—	313,852
Other long-term liabilities	3,719	—	119,432	208	—	123,359
Total liabilities	3,863	655,626	781,732	31,269	—	1,472,490
Commitments and Contingencies (Note 11)						
Stockholders' equity (deficit)	1,007,496	1,011,359	1,509,930	50,992	(2,572,281)	1,007,496
	$1,011,359	$1,666,985	$ 2,291,662	$ 82,261	$(2,572,281)	$ 2,479,986

TALOS ENERGY INC.
CONSOLIDATING BALANCE SHEET
AS OF DECEMBER 31, 2017
(In thousands)

	Parent	Subsidiary Issuers	Guarantors	Non-Guarantors	Elimination	Consolidated
ASSETS						
Current assets:						
Cash and cash equivalents	$ —	$ 22,315	$ 7,806	$ 2,070	$ —	$ 32,191
Restricted cash	—	—	1,242	—	—	1,242
Accounts receivable, net						
Trade, net	—	—	62,871	—	—	62,871
Joint interest, net	—	—	11,659	1,954	—	13,613
Other	—	938	5,863	5,685	—	12,486
Assets from price risk management activities	—	1,406	157	—	—	1,563
Prepaid assets	—	—	17,919	12	—	17,931
Inventory	—	—	840	—	—	840
Other current assets	—	—	2,148	—	—	2,148
Total current assets	—	24,659	110,505	9,721	—	144,885
Property and equipment:						
Proved properties	—	—	2,440,811	—	—	2,440,811
Unproved properties, not subject to amortization	—	—	41,259	30,743	—	72,002
Other property and equipment	—	7,266	1,580	11	—	8,857
Total property and equipment	—	7,266	2,483,650	30,754	—	2,521,670
Accumulated depreciation, depletion and amortization	—	(6,355)	(1,424,527)	(8)	—	(1,430,890)
Total property and equipment, net	—	911	1,059,123	30,746	—	1,090,780
Other long-term assets:						
Assets from price risk management activities	—	345	—	—	—	345
Other well equipment inventory	—	—	2,577	—	—	2,577
Investments in subsidiaries	(54,087)	697,663	—	—	(643,576)	—
Other assets	—	364	326	16	—	706
Total assets	$ (54,087)	$ 723,942	$ 1,172,531	$ 40,483	$ (643,576)	$ 1,239,293
LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)						
Current liabilities:						
Accounts payable	$ —	$ 1,124	$ 70,458	$ 1,099	$ —	$ 72,681
Accrued liabilities	—	6,516	80,464	993	—	87,973
Accrued royalties	—	—	24,208	—	—	24,208
Current portion of long-term debt	—	24,977	—	—	—	24,977
Current portion of asset retirement obligations	—	—	39,741	—	—	39,741
Liabilities from price risk management activities	—	46,580	3,377	—	—	49,957
Accrued interest payable	—	8,742	—	—	—	8,742
Other current liabilities	—	—	15,188	—	—	15,188
Total current liabilities	—	87,939	233,436	2,092	—	323,467
Long-term debt, net of discount and deferred financing costs	—	672,581	—	—	—	672,581
Asset retirement obligations	—	—	174,992	—	—	174,992
Liabilities from price risk management activities	—	17,509	1,272	—	—	18,781
Other long-term liabilities	—	—	103,559	—	—	103,559
Total liabilities	—	778,029	513,259	2,092	—	1,293,380
Commitments and Contingencies (Note 11)						
Stockholders' equity (deficit)	(54,087)	(54,087)	659,272	38,391	(643,576)	(54,087)
	$ (54,087)	$ 723,942	$ 1,172,531	$ 40,483	$ (643,576)	$ 1,239,293

TALOS ENERGY INC.
CONSOLIDATING STATEMENT OF OPERATIONS
FOR THE YEAR ENDED DECEMBER 31, 2018
(In thousands)

	Parent	Subsidiary Issuers	Guarantors	Non-Guarantors	Elimination	Consolidated
Revenues:						
Oil revenue	$ —	$ —	$ 781,815	$ —	$ —	$ 781,815
Natural gas revenue	—	—	73,610	—	—	73,610
NGL revenue	—	—	35,863	—	—	35,863
Total revenue	—	—	891,288	—	—	891,288
Operating expenses:						
Direct lease operating expense	—	—	145,988	—	—	145,988
Insurance	—	—	15,342	—	—	15,342
Production taxes	—	—	1,989	—	—	1,989
Total lease operating expense	—	—	163,319	—	—	163,319
Workover and maintenance expense	—	—	64,961	—	—	64,961
Depreciation, depletion and amortization	—	1,955	286,760	4	—	288,719
Accretion expense	—	—	35,344	—	—	35,344
General and administrative expense	142	43,841	40,035	1,798	—	85,816
Total operating expenses	142	45,796	590,419	1,802	—	638,159
Operating income (loss)	(142)	(45,796)	300,869	(1,802)	—	253,129
Interest expense	—	(58,172)	(30,255)	(1,687)	—	(90,114)
Price risk management activities income	—	50,025	10,410	—	—	60,435
Other income (loss)	—	(1,563)	874	1,701	—	1,012
Income tax expense	(1,065)	—	(360)	(1,497)	—	(2,922)
Equity earnings (losses) from subsidiaries	222,747	278,253	—	—	(501,000)	—
Net income (loss)	$221,540	$ 222,747	$ 281,538	$ (3,285)	$ (501,000)	$ 221,540

TALOS ENERGY INC.
CONSOLIDATING STATEMENT OF OPERATIONS
FOR THE YEAR ENDED DECEMBER 31, 2017
(In thousands)

	Parent	Subsidiary Issuers	Guarantors	Non-Guarantors	Elimination	Consolidated
Revenues:						
Oil revenue	$ —	$ —	$ 344,781	$ —	$ —	$ 344,781
Natural gas revenue	—	—	48,886	—	—	48,886
NGL revenue	—	—	16,658	—	—	16,658
Other	—	—	2,503	—	—	2,503
Total revenue	—	—	412,828	—	—	412,828
Operating expenses:						
Direct lease operating expense	—	—	109,180	—	—	109,180
Insurance	—	—	10,743	—	—	10,743
Production taxes	—	—	1,460	—	—	1,460
Total lease operating expense	—	—	121,383	—	—	121,383
Workover and maintenance expense	—	—	32,825	—	—	32,825
Depreciation, depletion and amortization	—	1,401	155,947	4	—	157,352
Accretion expense	—	—	19,295	—	—	19,295
General and administrative expense	—	21,882	14,172	619	—	36,673
Total operating expenses	—	23,283	343,622	623	—	367,528
Operating income (loss)	—	(23,283)	69,206	(623)	—	45,300
Interest expense	—	(48,236)	(30,252)	(2,446)	—	(80,934)
Price risk management activities expense	—	(22,998)	(4,565)	—	—	(27,563)
Other income (expense)	—	600	(333)	62	—	329
Equity earnings from subsidiaries	(62,868)	31,049	—	—	31,819	—
Net income (loss)	$(62,868)	$ (62,868)	$ 34,056	$ (3,007)	$ 31,819	$ (62,868)

TALOS ENERGY INC.
CONSOLIDATING STATEMENT OF OPERATIONS
FOR THE YEAR ENDED DECEMBER 31, 2016
(In thousands)

	Parent	Subsidiary Issuers	Guarantors	Non-Guarantors	Elimination	Consolidated
Revenues:						
Oil revenue	$ —	$ —	$ 197,583	$ —	—	$ 197,583
Natural gas revenue	—	—	42,705	—	—	42,705
NGL revenue	—	—	9,532	—	—	9,532
Other	—	—	8,934	—	—	8,934
Total revenue	—	—	258,754	—	—	258,754
Operating expenses:						
Direct lease operating expense	—	—	124,360	—	—	124,360
Insurance	—	—	13,101	—	—	13,101
Production taxes	—	—	1,958	—	—	1,958
Total lease operating expense	—	—	139,419	—	—	139,419
Workover and maintenance expense	—	—	24,810	—	—	24,810
Depreciation, depletion and amortization	—	1,553	123,132	4	—	124,689
Accretion expense	—	—	21,829	—	—	21,829
General and administrative expense	—	13,204	15,044	438	—	28,686
Total operating expenses	—	14,757	324,234	442	—	339,433
Operating loss	—	(14,757)	(65,480)	(442)	—	(80,679)
Interest expense	—	(47,291)	(19,680)	(3,444)	—	(70,415)
Price risk management activities expense	—	(57,398)	—	—	—	(57,398)
Other income (expense)	—	—	430	(25)	—	405
Equity earnings from subsidiaries	(208,087)	(88,641)	—	—	296,728	—
Net income (loss)	$(208,087)	$ (208,087)	$ (84,730)	$ (3,911)	$ 296,728	$ (208,087)

TALOS ENERGY INC.
CONSOLIDATING STATEMENT OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31, 2018
(In thousands)

	Parent	Subsidiary Issuers	Guarantors	Non-Guarantors	Elimination	Consolidated
Cash flows from operating activities:						
Net cash provided by (used in) operating activities	$ —	$ (193,088)	$ 442,890	$ 13,643	$ —	$ 263,445
Cash flows from investing activities:						
Exploration, development, and other capital expenditures	—	(13,404)	(227,228)	(282)	—	(240,914)
Cash paid for acquisitions, net of cash acquired	—	—	278,409	—	—	278,409
Investments in subsidiaries	—	(1,316,588)	—	—	1,316,588	—
Distributions from subsidiaries	—	1,694,460	9	—	(1,694,469)	—
Net cash provided by (used in) investing activities	—	364,468	51,190	(282)	(377,881)	37,495
Cash flows from financing activities:						
Redemption of Senior Notes and other long-term debt	—	(25,152)	(105)	—	—	(25,257)
Proceeds from Bank Credit Facility	—	319,000	—	—	—	319,000
Repayment of Bank Credit Facility	—	(54,000)	—	—	—	(54,000)
Repayment of LLC Bank Credit Facility	—	(403,000)	—	—	—	(403,000)
Deferred financing costs	—	(17,002)	—	—	—	(17,002)
Payment of capital lease	—	—	(12,952)	—	—	(12,952)
Capital contributions	—	—	1,301,876	14,712	(1,316,588)	—
Distributions to Subsidiary Issuer	—	—	(1,689,898)	(4,571)	1,694,469	—
Net cash provided by (used in) financing activities	—	(180,154)	(401,079)	10,141	377,881	(193,211)
Net increase (decrease) in cash, cash equivalents and restricted cash	—	(8,774)	93,001	23,502	—	107,729
Cash, cash equivalents and restricted cash						
Balance, beginning of period	—	22,315	9,048	2,070	—	33,433
Balance, end of period	$ —	$ 13,541	$ 102,049	$ 25,572	$ —	$ 141,162

TALOS ENERGY INC.
CONSOLIDATING STATEMENT OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31, 2017
(In thousands)

	Parent	Subsidiary Issuers	Guarantors	Non-Guarantors	Elimination	Consolidated
Cash flows from operating activities:						
Net cash provided by (used in) operating activities	$ —	$ (30,245)	$ 204,419	$ 1,879	$ —	$ 176,053
Cash flows from investing activities:						
Exploration, development, and other capital expenditures	—	(260)	(132,317)	(22,600)	—	(155,177)
Cash paid for acquisitions, net of cash acquired	—	—	(2,464)	—	—	(2,464)
Investments in subsidiaries	—	(577,055)	—	—	577,055	—
Distributions from subsidiaries	—	611,526	6,041	—	(617,567)	—
Net cash provided by (used in) investing activities	—	34,211	(128,740)	(22,600)	(40,512)	(157,641)
Cash flows from financing activities:						
Redemption of 2018 Senior Notes	—	(1,000)	—	—	—	(1,000)
Proceeds from Bank Credit Facility	—	10,000	—	—	—	10,000
Repayment of Bank Credit Facility	—	(15,000)	—	—	—	(15,000)
Payments of capital lease	—	—	(12,412)	—	—	(12,412)
Capital contributions	—	—	550,555	26,500	(577,055)	—
Distributions to subsidiaries	—	—	(611,526)	(6,041)	617,567	—
Net cash provided by (used in) financing activities	—	(6,000)	(73,383)	20,459	40,512	(18,412)
Net increase (decrease) in cash, cash equivalents and restricted cash	—	(2,034)	2,296	(262)	—	—
Cash, cash equivalents and restricted cash:						
Balance, beginning of period	—	24,349	6,752	2,332	—	33,433
Balance, end of period	$ —	$ 22,315	$ 9,048	$ 2,070	$ —	$ 33,433

TALOS ENERGY INC.
CONSOLIDATING STATEMENT OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31, 2016
(In thousands)

	Parent	Subsidiary Issuers	Guarantors	Non-Guarantors	Elimination	Consolidated
Cash flows from operating activities:						
Net cash provided by (used in) operating activities	$ —	$ 124,698	$ (2,806)	$ (5,769)	—	$ 116,123
Cash flows from investing activities:						
Exploration, development, and other capital expenditures	—	(301)	(106,647)	(6,084)	—	(113,032)
Cash paid for acquisitions, net of cash acquired	—	—	(85,886)	—	—	(85,886)
Investments in subsidiaries	(91,891)	(524,192)	—	—	616,083	—
Distributions from subsidiaries	—	411,074	—	—	(411,074)	—
Net cash provided by (used in) investing activities	(91,891)	(113,419)	(192,533)	(6,084)	205,009	(198,918)
Cash flows from financing activities:						
Proceeds from Bank Credit Facility	—	15,000	—	—	—	15,000
Repayment of Bank Credit Facility	—	(10,000)	—	—	—	(10,000)
Payments of capital lease	—	—	(5,267)	—	—	(5,267)
Capital contributions	—	—	599,630	16,453	(616,083)	—
Distributions to subsidiaries	—	—	(408,050)	(3,024)	411,074	—
Contributions from Sponsors	93,750	—	—	—	—	93,750
Distributions to Sponsors	(1,859)	—	—	—	—	(1,859)
Net cash provided by (used in) financing activities	91,891	5,000	186,313	13,429	(205,009)	91,624
Net increase (decrease) in cash, cash equivalents and restricted cash	—	16,279	(9,026)	1,576	—	8,829
Cash, cash equivalents and restricted cash:						
Balance, beginning of period	—	8,070	15,778	756	—	24,604
Balance, end of period	$ —	$ 24,349	$ 6,752	$ 2,332	$ —	$ 33,433

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 2018				
Revenues	$ 145,850	$ 203,906	$ 282,868	$ 258,664
Operating income	48,584	39,211	91,361	73,973
Price risk management activities income (expense)	(51,976)	(91,176)	(53,330)	256,917
Net income (loss)	$ (22,943)	$ (74,912)	$ 13,109	$ 306,286
Net income (loss) per common share:				
Basic	$ (0.73)	$ (1.69)	$ 0.24	$ 5.66
Diluted	$ (0.73)	$ (1.69)	$ 0.24	$ 5.66
Weighted average common shares outstanding:				
Basic	31,244	44,336	54,156	54,156
Diluted	31,244	44,336	54,164	54,159
Quarter Ended 2017				
Revenues	$ 101,824	$ 95,426	$ 99,962	$ 115,616
Operating income	7,287	6,314	13,329	18,370
Price risk management activities income (expense)	45,893	38,995	(28,086)	(84,365)
Net income (loss)	$ 34,462	$ 24,607	$ (36,177)	$ (85,760)
Net income (loss) per common share:				
Basic	$ 1.10	$ 0.79	$ (1.16)	$ (2.74)
Diluted	$ 1.10	$ 0.79	$ (1.16)	$ (2.74)
Weighted average common shares outstanding:				
Basic	31,244	31,244	31,244	31,244
Diluted	31,244	31,244	31,244	31,244

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):

	December 31,	
	2018	2017
Proved properties	$ 3,629,430	$ 2,440,811
Unproved oil and gas properties, not subject to amortization	108,209	72,002
Total oil and gas properties	3,737,639	2,512,813
Less: Accumulated depletion and amortization	(1,709,614)	(1,423,829)
Net capitalized costs	$ 2,028,025	$ 1,088,984
Depletion and amortization rate per Boe	$ 17.07	$ 14.85

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, 2018 and 2017 the Company's liability for oil and gas asset retirement obligations totaled $382.8 million and $214.7 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,		
	2018	2017	2016
Property acquisition costs:			
Proved properties	$ 850,515	$ 1,108	$ 77,906
Unproved properties, not subject to amortization	65,063	5,778	15,919
Total property acquisition costs	915,578	6,886	93,825
Exploration costs	93,780	82,887	27,807
Development costs	215,467	114,846	195,869
Total costs incurred	$ 1,224,825	$ 204,619	$ 317,501

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, 2018, 2017 and 2016, 100% of proved oil, natural gas and NGL reserves attributable to all of the Company's oil and natural gas properties were estimated and complied 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, 2015	46,354	129,224	4,581	72,473
Revision of previous estimates	(1,712)	10,024	(352)	(394)
Production	(5,126)	(19,001)	(603)	(8,896)
Purchases of reserves	11,128	11,208	950	13,946
Extensions and discoveries	21,722	19,149	1,660	26,573
Total proved reserves at December 31, 2016	72,366	150,604	6,236	103,702
Revision of previous estimates	(2,673)	(15,860)	250	(5,067)
Production	(7,048)	(16,308)	(706)	(10,472)
Extensions and discoveries	10,159	9,220	767	12,462
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
Total proved developed reserves as of:				
December 31, 2016	45,753	96,122	4,032	65,805
December 31, 2017	37,460	77,577	3,315	53,704
December 31, 2018	85,530	131,364	8,104	115,528
Total proved undeveloped reserves as of:				
December 31, 2016	26,613	54,482	2,204	37,897
December 31, 2017	35,344	50,079	3,232	46,921
December 31, 2018	27,009	39,660	2,592	36,211

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.

During 2017, the Company added 12.5 MMBoe of estimated proved reserves from extensions and discoveries primarily from drilling the Tornado II exploration prospect in the Phoenix Field. The increase was offset by a decrease of 10.5 MMBoe of production and 5.1 MMBoe of negative performance revisions.

During 2016, the Company added 13.9 MMBoe of estimated proved reserves through the purchase of reserves from the Sojitz Acquisition. The Company also added 26.6 MMBoe of estimated proved reserves from extensions and discoveries from successful drilling of the Tornado exploration well in the Phoenix Field.

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):

	December 31,		
	2018	2017	2016
Future cash inflows	$ 8,654,631	$ 4,308,863	$ 3,390,612
Future costs:			
Production	(1,740,850)	(815,509)	(775,354)
Development and abandonment	(1,349,005)	(823,164)	(664,254)
Future net cash flows before income taxes	5,564,776	2,670,190	1,951,004
Future income tax expense [1]	(862,473)	—	—
Future net cash flows after income taxes	4,702,303	2,670,190	1,951,004
Discount at 10% annual rate	(1,362,057)	(862,521)	(614,969)
Standardized measure of discounted future net cash flows	$ 3,340,246	$ 1,807,669	$ 1,336,035

(1) For December 31, 2017 and 2016, the standardized measure of discounted future net cash flows did not include the impact of future federal income taxes because Talos Energy LLC was not subject to federal income taxes prior to the Stone Combination.

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,		
	2018	2017	2016
Oil price per Bbl	$ 69.42	$ 51.36	$ 40.02
Natural gas prices per Mcf	$ 3.08	$ 3.20	$ 2.66
NGL price per Bbl	$ 29.50	$ 24.64	$ 14.96

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, 2018	2017	2016
Standardized measure, beginning of year	$ 1,807,669	$ 1,336,035	$ 602,981
Changes during the year:			
Sales and transfers of oil, net gas and NGLs produced during the period	(727,969)	(288,942)	(114,625)
Net change in prices and production costs	1,578,330	555,100	80,174
Changes in estimated future development costs	32,328	(156,282)	2,292
Previously estimated development costs incurred	45,937	146,687	108,484
Accretion of discount	180,767	133,603	60,298
Net change in income taxes[(1)]	(585,017)	—	—
Purchases of reserves	943,519	—	222,581
Extensions and discoveries	148,068	328,565	479,833
Net change due to revision in quantity estimates	190,853	(113,629)	(5,685)
Changes in production rates (timing) and other	(274,239)	(133,468)	(100,298)
Total	1,532,577	471,634	733,054
Standardized measure, end of year	$ 3,340,246	$ 1,807,669	$ 1,336,035

(1) For December 31, 2017 and 2016, the standardized measure of discounted future net cash flows did not include the impact of future federal income taxes because Talos Energy LLC was not subject to federal income taxes prior to the Stone Combination.

Note 15 —Subsequent Events

Gunflint Acquisition

On January 11, 2019, the Company entered into a Purchase Sale Agreement with Samson Offshore Mapleleaf, LLC to acquire an approximate 9.6% non-operated working interest in the Gunflint Field located in the Mississippi Canyon area for $29.6 million.

Derivative Contracts

For additional information, see Note 5 — *Financial Instruments.*

Debt

For additional information, see Note 6 — *Debt*.

[THIS PAGE INTENTIONALLY LEFT BLANK]

[THIS PAGE INTENTIONALLY LEFT BLANK]

[THIS PAGE INTENTIONALLY LEFT BLANK]

CORPORATE INFORMATION

CORPORATE OFFICERS

Timothy S. Duncan
President and Chief Executive Officer

Stephen E. Heitzman
Executive Vice President
and Chief Operating Officer

John A. Parker
Executive Vice President –
Exploration

Michael L. Harding II
Executive Vice President,
Chief Financial Officer and Treasurer

William S. Moss III
Executive Vice President
and General Counsel

John B. Spath
Senior Vice President –
Drilling and Production Operations

Robert Sheninger
Vice President –
Health, Safety, Environmental
and Sustainability

C. Gordon Lindsey
Vice President –
Corporate Development

Deborah Huston
Vice President and
Deputy General Counsel

Loren Long
Vice President –
Mexico

BOARD OF DIRECTORS

Neal P. Goldman*
Managing Member, SAGE Capital
Investments, LLC

Timothy S. Duncan
President and Chief Executive Officer,
Talos Energy Inc.

Christine Hommes
Principal, 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
Investor

Robert M. Tichio
Partner, Riverstone Holdings LLC

James M. Trimble
Chairman, Crestone Peak Resources

Olivia C. Wassenaar
Partner, Apollo Global Management, LLC

** Chairman of the Board*

CORPORATE OFFICE
333 Clay St., Suite 3300
Houston, TX 77002
Phone: 713-328-3000

WEBSITE
www.talosenergy.com

STOCK EXCHANGE LISTING
New York Stock Exchange
Symbol: TALO

ANNUAL MEETING
May 6, 2019
10:30 a.m. CT
Three Allen Center
333 Clay Street, Suite 3300
Houston, TX 77002

FORM 10-K
Copies of the corporation's 10-K
are available on our website at
www.talosenergy.com

AUDITORS
Ernst & Young
Houston, TX

SHAREHOLDER SERVICES
Computershare
Mailing: P.O. Box 505000
Louisville, KY 40233
1-800-962-4284 (Toll-Free)
1-781-575-3120 (International)

OVERNIGHT MAIL
462 South 4th Street
Suite 1600
Louisville, KY 40202

INVESTOR RELATIONS
Additional corporate information
is available on our website at
www.talosenergy.com

CORPORATE OFFICE
333 Clay St., Suite 3300
Houston, TX 77002
Phone: 713-328-3000

www.talosenergy.com

TALOS ENERGY