ULTRA PETROLEUM CORP
Form 10-K
March 08, 2019
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2018

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission file number 001-33614

ULTRA PETROLEUM CORP.

(Exact name of registrant as specified in its charter)

Yukon, Canada	N/A
(State or other jurisdiction of incorporation or organization)	(I.R.S. employer identification number)
116 Inverness Drive East, Suite 400 Englewood, Colorado	80112
(Address of principal executive offices)	(Zip code)

(303) 708-9740

(Registrant’s telephone number, including area code)

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

Title of Each Class	Name of Exchange on Which Registered
Common Shares, without par value	NASDAQ Global Select 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 Section 15(d) of the Act. YES NO

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (Section 232.405) 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 (Section 229.405) 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 was $369,920,487 as of June 29, 2018 (based on the last reported sales price of $2.31 of such stock on the NASDAQ Global Select Market on such date).

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

The number of common shares, without par value, of Ultra Petroleum Corp., outstanding as of February 28, 2019 was 197,383,295.

Documents incorporated by reference:

Portions of the registrant's definitive proxy statement relating to its 2018 and 2019 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2018, are incorporated by reference to the extent set forth in Part III, Items 10-14 of this Form 10-K.

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PART I

Item 1. Business.
General

Ultra Petroleum Corp. and its wholly-owned subsidiaries (collectively the “Company”, “Ultra”, “our”, “we”, or “us”) is an independent oil and gas company engaged in the development, production, operation, exploration and acquisition of oil and natural gas properties. The Company was incorporated in 1979, under the laws of the Province of British Columbia, Canada. Ultra remains a Canadian company, and since March 2000, has operated under the laws of Yukon, Canada pursuant to Section 190 of the Yukon Business Corporations Act. The Company’s principal business activities are developing and producing its long-life natural gas reserves in the Pinedale and Jonah fields of the Green River Basin of southwest Wyoming.

The Company’s annual report on Form 10-K, quarterly reports on Form 10-Q, and current reports on Form 8-K, as well as any amendments to such reports and all other filings pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the “Exchange Act”), are available free of charge to the public on the Company’s website at www.ultrapetroleum.com as soon as reasonably practicable after such material is electronically filed with, or furnished to, the SEC. You may also request a copy of these filings at no cost by making written or telephone requests for copies to Ultra Petroleum Corp., Investor Relations, 116 Inverness Drive East, Suite 400, Englewood, CO 80112, (303) 708-9740, ext. 9898. The SEC maintains an internet site that contains reports, proxy and information statements, and other information regarding the Company. The SEC’s website address is www.sec.gov.

Oil and Gas Properties Overview

Principal Operating Area

Ultra’s operations in southwest Wyoming have historically focused on developing its long-life natural gas reserves in a tight gas sand trend located in the Green River Basin. The Company targets sands of the upper Cretaceous Lance Pool in the Pinedale and Jonah fields. The Lance Pool, as administered by the Wyoming Oil and Gas Conservation Commission (“WOGCC”), includes sands of the Lance formation at depths between approximately 8,000 and 12,000 feet and the Mesaverde formation at depths between approximately 12,000 and 14,000 feet. As of December 31, 2018, Ultra owned interests in approximately 114,000 gross (79,000 net) acres in Wyoming covering approximately 190 square miles. Following the sale of the Company’s Pennsylvania properties in late 2017 and Utah assets in late 2018, all oil and gas operations are now focused in the Pinedale and Jonah fields.

2018 and 2017 Divestitures

The Company previously had operations in the Uinta Basin in Utah and in north central Pennsylvania.

On September 25, 2018, the Company completed the sale of its Utah assets for net cash proceeds of $69.3 million, including management fees of $0.6 million. The divested assets consisted primarily of oil and gas properties. Prior to the sale, production from the Company’s Utah assets totaled approximately 420,000 Bbl of oil and 745,000 Mcf of natural gas in 2018.

During the fourth quarter of 2017, the Company divested its properties in the Pennsylvania Devonian aged Marcellus Shale, for net cash proceeds of approximately $115.0 million. Prior to the sale, production from the Pennsylvania assets totaled approximately 11.2 million Mcf of natural gas in 2017.

Mission and Strategy

Ultra's mission is to profitably grow as an upstream oil and gas company for the long-term benefit of its shareholders. Ultra's strategy to achieve this goal includes managing its portfolio of assets in Wyoming, maintaining a disciplined approach to capital investment, maximizing earnings and cash flows by controlling costs, utilizing advancements in drilling technologies to maximize results, and improving its financial flexibility.

High Return Portfolio. Ultra seeks to maintain a portfolio of properties that provide long-term, profitable growth through development in areas that support sustainable, lower-risk, repeatable, high-return drilling projects. The Company evaluates opportunities for the acquisition, exploration, and development of additional oil and natural gas properties that afford risk-adjusted returns in excess of or equal to its current set of investment alternatives.

Disciplined Capital Investment. The Company's business strategy includes proactive and regular review of its portfolio of investment opportunities with a focus on investments that produce positive returns in order to optimize return to its shareholders. The Company seeks to develop the resource from existing assets, while spending within cash flows in order to maximize profitability.

Focus on Maximizing Value. Ultra strives to maintain one of the lowest cost structures in the industry in terms of both adding and producing oil and natural gas reserves. The Company continues to focus on improving its drilling and production results using advanced technologies and detailed technical analysis of its properties, while maintaining its low-cost structure, adhering to industry and regulatory best practices, maintaining strict safety and environmental standards, and recruiting and retaining top talent within the Company.

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Financial Liquidity. Improving financial flexibility and strengthening the balance sheet are also key components of Ultra's business philosophy. At December 31, 2018, the Company had cash on hand of $17.0 million and outstanding debt of $2.2 billion. At December 31, 2018, the Company had borrowing base capacity of $325.0 million under its revolving credit facility (the "Revolving Credit Facility") pursuant to the borrowing base redetermination, of which $104.0 million was outstanding. Further, the Company seeks to improve its cash flow visibility by hedging a portion of its forecasted volumes on an annual basis in order to manage commodity price risks and provide cash flow predictability.

Subsequent to December 31, 2018, the Company reaffirmed its borrowing base at $1.3 billion, providing for $325.0 million of availability, and also entered into a Fourth Amendment to the Revolving Credit Facility providing expansion of its allowed leverage metric, as well as other enhancements to the utility of the facility. The next borrowing base redetermination is scheduled for the fall of 2019. This proactive effort is one of several steps towards building in time to execute the Company's business plan and leverages the benefit from the December 2018 Exchange Transaction described below.

In December 2018, the Company exchanged (i) $505 million aggregate principal amount, or 72.1%, of the 6.875% Senior Notes due 2022 (the "2022 Notes") and (ii) $275 million aggregate principal amount, or 55%, of the 7.125% Senior Notes due 2025 (the "2025 Notes" and, together with the 2022 Notes, the "Unsecured Notes") of Ultra Resources, Inc., a Delaware corporation ("Ultra Resources"), a wholly owned subsidiary of the Company for (a) $545.0 million aggregate principal amount of new 9.00% Cash/2.00% PIK Senior Secured Second Lien Notes due July 2024 of Ultra Resources (the "Second Lien Notes") and (b) an aggregate of 10,919,499 new warrants of the Company entitling the holder thereof to purchase one common share of the Company (each a "Warrant" and collectively, the "Warrants") (such transaction, the "Exchange Transaction"). The Exchange Transaction reduced principal balance of the indebtedness by $235 million. Following the Exchange Transaction, the average debt maturity was extended to 5.1 years. The weighted average cost of debt prior to the Exchange Transaction was approximately 6.3% and increased to approximately 8% after the exchange.

See Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources" for a description of the Revolving Credit Facility and additional details regarding the Exchange Transaction.

Following the Exchange Transaction, subsequent to December 31, 2018, and through the date of this filing, the Company has successfully exchanged an additional $44.6 million aggregate principal amount of 2022 Notes for $27.0 million aggregate principal amount of Second Lien Notes, reducing indebtedness by $252.5 million (inclusive of the Exchange Transaction). Under the indenture governing the Second Lien Notes, the Company was permitted to exchange up to approximately $55.0 million of 2022 Notes for Second Lien Notes at terms that are the same or more favorable to the Company than the terms of the Exchange Transaction. The Company continues to retain the ability under the indenture to further exchange approximately $10.4 million of the remaining 2022 Notes within one year of the Exchange Transaction.

Exploration and Production

See Item 2. "Properties" for a description of our properties.

Green River Basin, Wyoming

During 2018, the Company participated in the drilling and casing of 116 vertical and 19 horizontal wells operated by the Company and others in Wyoming and continued its drilling and completion efficiency on its operated wells. In line with the Company's commitment to make its operations more efficient, the Company's operated well costs for vertical wells declined from an annual average of $3.8 million per well during 2014 to an annual average of $3.2 million per well during 2018, and $3.1 million in the fourth quarter of 2018 as the Company restored its primary vertical well development program. The reduction in costs is attributable to drilling efficiencies, such as pad drilling and simultaneous operations for drilling and completion activities, application of technology and service cost reductions. The Company operates 89% of its production in the Pinedale field. The horizontal well program in 2018 resulted in several successful wells; however, the majority of the horizontal program was marginally economic to uneconomic, causing the Company to suspend this program in the third quarter of 2018 in order to evaluate the results, including the application of advanced geologic and engineering analysis and detailed evaluation of the horizontal wells that had been developed. Ultra has completed one additional horizontal well in early 2019 and will integrate the results from this well into its analysis on developing the horizontal program.

During 2019, the Company plans, based on the availability of capital, to continue developing its position in the Pinedale field, and will continue to target tight gas sands of the Lance Pool, predominately through the development of vertical wells. All of the Company's drilling activity is conducted utilizing historical well performance, completion efficiency, and its extensive geological and geophysical data set. This data set is used to map the productive intervals, to refine areas of drilling focus, to identify areas for future extension of the Lance fairway with both vertical and horizontal wells, as well as to consider other deeper horizons that may be viable development candidates.

Utah

During 2018, the Company did not drill any wells on the Uinta Basin properties, The Company sold all of its Utah oil and gas properties in September 2018.

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Marketing and Pricing

Overview

During the year ended December 31, 2018, Ultra derived its revenues from the sale of its natural gas and associated condensate produced from wells operated by the Company in the Green River Basin in southwest Wyoming, and from the sale of crude oil and natural gas from wells operated by the Company in the Uinta Basin in Utah. In September 2018, the Company divested its properties on the Uinta Basin in Utah.

During 2018, 95% of the Company's production and 81% of its revenues were attributable to natural gas, with the balance attributable to associated condensate and crude oil. In the fourth quarter of 2018, subsequent to the sale of its Utah assets, 96% of Ultra's production and 89% of its revenue were from the sale of natural gas.

The Company's natural gas and oil revenues are determined by prevailing market prices in the Rocky Mountain region of the United States, specifically, southwest Wyoming as virtually all of its natural gas sold at the Inside FERC First of Month Index for Northwest Pipeline — Rocky Mountains ("NwRox") is the price that is reflective of the Company's gas sold in the Opal, Wyoming area. The NwRox and New York Mercantile Exchange ("NYMEX") is the price that is reflective of the Company's gas sold in the Opal, Wyoming area.

The NwRox can be volatile from time to time, particularly in peak winter and summer periods, as evidenced in November and December 2018 when natural gas at that delivery point was selling for $0.05 and $0.98, respectively, per MMBtu above NYMEX pricing for natural gas. We also use derivative instruments in the management of the cash flows of our business, as discussed below.

Natural Gas Marketing

Ultra currently sells all its natural gas production to a diverse group of third-party, non-affiliated entities in a portfolio of transactions of various durations and prices (daily, monthly and longer term). The Company's customer base includes a significant number of customers situated in the various regions of the United States. The sale of the Company's natural gas is "as produced".

Midstream services. For its natural gas production in Wyoming, the Company has entered into various gathering and processing agreements with midstream service providers that gather, compress and process natural gas owned or controlled by the Company from its producing wells in the Pinedale Anticline and Jonah fields. Under these agreements, the midstream service providers continue to maintain and upgrade their facilities in southwest Wyoming to ensure reliability and certainty of operations. The Company believes that the capacity of the midstream infrastructure related to its production will continue to be adequate to allow it to sell all its available natural gas production.

Basis differentials. The market price for natural gas is influenced by a number of regional and national factors which are beyond the Company's ability to control. These factors include, among others, weather in the western United States, natural gas supplies, imports from Canada, natural gas demand, inventory levels in natural gas storage fields, and natural gas pipeline capacity to export gas from the basins where the Company's production is located. See Item 1A. "Risk Factors" for more information about risks to our financial condition and business results associated with basis differentials.

The Rocky Mountain region is a net exporter of natural gas because local natural gas production exceeds local demand, especially during non-winter months. As a result, natural gas production in southwest Wyoming has from time to time sold at a discount relative to other U.S. natural gas production sources or market areas. These regional pricing differentials, or discounts, are typically referred to as “basis” or “basis differentials” and are reflective, to some extent, of (i) the costs associated with transporting the Company’s gas to markets in other regions or states, and (ii) the availability of pipeline capacity to move the Company’s gas to market.

Since the completion of the Rockies Express and Ruby pipelines, the average annual basis for NwRox averaged 5.6% below Henry Hub from 2012 through 2016. The additional capacity of these two pipelines has had a significant positive impact on the value that the Company receives for its natural gas production in southwest Wyoming, as compared to prior years when constraints were prevalent in the region. However, during 2017 and 2018, NwRox basis has weakened from levels realized in 2012 through 2016 mainly due to weakening fundamentals in the Company’s core delivery area, California, and increasing flows from regions that produce significant quantities of oil and are connected by gas pipelines to the California market. In 2017 and 2018, NwRox basis averaged an 11.5% and 14.4%, respectively, discount to Henry Hub. This expansion in the percentage differential is due to lower absolute natural gas prices as well as significant competition for markets due to robust natural gas production in constrained areas such as the Permian and Delaware Basins in Texas, the Marcellus Shale in Pennsylvania and the Utica Shale in Ohio. The average basis differential of NwRox was $0.36 and $0.44 below the Henry Hub in 2017 and 2018, respectively.

While trades indicate that the basis differentials for the forward-looking basis market for 2019 and 2020 are negative to Henry Hub by approximately $0.30 and $0.46, respectively, there is expected improvement in NwRox basis beginning in 2020 as pipeline expansions and processing capacity in the Permian and Delaware Basins increase as well as processing and export capacity from the Houston and Beaumont areas. The increased take-away capacity in these regions may improve the NwRox basis as competition for gas flowing into the mid-continent region and the West Coast are redirected to more local markets.

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The table below provides a historical perspective on average quarterly basis differentials for Wyoming natural gas (NwRox). The basis differential is expressed as a percentage of the Henry Hub price as reported by Platt's M2M (Mark to Market) Report and Bloomberg on December 31, 2018 and 2017.

	2018 1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
NwRox	83 %	70 %	80 %	103 %
NYMEX	$3.00	$ 2.80	$ 2.90	$ 3.64

	2017 1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
NwRox	92 %	84 %	87 %	89 %
NYMEX	$3.32	$ 3.18	$ 3.00	$ 2.93

Oil Marketing

Wyoming. The Company markets its Wyoming condensate to various purchasers, which are primarily refiners in the Salt Lake City, Utah area. The Company's condensate realized pricing is typically based on New York Mercantile Exchange crude futures daily settlement prices, adjusted for a negotiated location/transportation differential. All of the Company's condensate sales are denominated in U.S. dollars per barrel and are paid monthly. The Company routinely maintains only operating inventories of condensate production and sells its product on an "as produced" basis. A portion of the Company's condensate sales are entered into by its operating partners in the Pinedale field. Over 94% of oil is transported via pipeline, thereby greatly reducing the risk of spills and losses. During 2018, the Company realized a positive differential of $1.84, excluding anomalies for pipeline outages, to a West Texas Intermediate price. The improvement in the differential was a result of strong refining demand for the quality of condensate produced in the Pinedale area. This trend of strengthening oil differentials is expected to continue in 2019, as evidence by the contracts in place through 2019 at a positive differential of $3.23 per Bbl.

Utah. Prior to the Company's sale of its Uinta Basin properties in September 2018, such properties produced what is typically referred to as Black Wax Crude, considered a medium grade of crude oil. This oil was marketed through short-term or long-term contracts with refiners in the Salt Lake City, Utah area. The price for the Company's crude oil production was typically based off of NYMEX pricing for West Texas Intermediate Crude Oil or from a posting for Black Wax Crude in the Uinta Basin, less a negotiated location/transportation discount or differential.

Derivatives

The Company, from time to time and in the regular course of its business, enters into hedges for volumes equivalent to a portion of expected future production volumes, primarily through the use of financial swaps, collars and puts with creditworthy financial counterparties (See Note 8), or through the use of fixed price, forward sales of physical product. The Company's Revolving Credit Facility requires the Company to hedge 65% of forecast proved producing natural gas production, based on its most recent reserve report for 18 months from the end of the given quarter. This requirement is in effect through September 30, 2019. After that time, the requirement decreases to 50% of the estimated proved producing forecast for natural gas through March 31, 2020. This means the Company may unwind hedges after September 30, 2019 at its discretion, provided the Company remains hedged at the 50% level for natural gas. Additionally, the Revolving Credit Facility limits the amount of hedging to 85% of forecast production for all products within a given quarter. The Company plans to enter into additional hedge positions in much the same manner as it has done previously. See Item 7A. "Quantitative and Qualitative Disclosures About Market Risk".

The Company considers the requirements of the Revolving Credit Facility when developing its hedging policy. The Company's management and board of directors has a Hedge Committee that reviews the forecast production, the requirements under the Revolving Credit Facility, and the market outlook to determine the timing and the manner in which to hedge with the underlying goal to provide a level of cash flow predictivity while preserving some flexibility to participate in upward price movements.

Significant Counterparties

A significant counterparty is defined as one that individually accounts for 10% or more of the Company's total revenues during the year. In 2018, the Company had no single counterparty that represented 10% or more of the Company's total revenues.

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The Company maintains credit policies intended to mitigate the risk of uncollectible accounts receivable related to the sale of natural gas and condensate as well as commodity derivatives. A more complete description of the Company's credit policies is described in Note 13. The Company takes measures to ensure collectability with its purchasers through regular credit monitoring and reviews. As necessary, the Company requires prepayment, letters of credit or parental guarantees from its purchasers for the periods of exposure. The Company did not have any outstanding, uncollectible accounts for its natural gas and oil sales at December 31, 2018.

Regulatory Matters

The Company's oil and gas operations are subject to a number of regulations. Governing agencies may include one or more of the following levels: federal, regional, state, county, municipality, Tribal or other public entities. In general, the purposes of these regulations are to prevent waste of oil and natural gas resources, protect the rights of surface and mineral owners, regulate interstate transportation of oil and gas, and to govern environmental quality. Common forms of regulations may include:

- Notification to stakeholders of proposed and ongoing operations;
- Nondiscrimination statutes;
- Royalty and related valuation requirements;
- On-site security and bonding requirements;
- Location and density of drilling;
- Method of drilling, completing and operating wells;
- Measurement and reporting of oil and gas;
- Rates, terms and conditions applicable to the interstate transportation of oil and gas;
- Production, severance and ad valorem taxes;
- Management of produced water and waste; and
- Surface use, reclamation and plugging and abandonment of wells.

A significant portion of the Company's operations are located on federal lands in the Pinedale and Jonah Fields of Sublette County, Wyoming. The development activities in these fields are subject to the regulation of the U.S. Bureau of Land Management ("BLM") which is responsible for governing their surface and mineral rights and regulating certain development activities in these fields. As required under the National Environmental Policy Act ("NEPA"), an Environmental Impact Statement ("EIS") was prepared to quantify and address potential impacts of natural gas development in both the Pinedale and Jonah fields. In March 2006, the BLM issued its Record of Decision ("ROD") which provides broad authorization for the development activities currently occurring in the Jonah Area. In September 2008, the BLM issued its ROD that currently governs the development activities in the Pinedale Area. In addition to the overarching authorizations provided by the Jonah and Pinedale RODs, BLM issues site-specific authorizations such as rights of way and permits to drill on an ongoing basis.

The Pinedale ROD includes some significant components to ensure the orderly and responsible development of natural gas concurrent to minimizing the environmental impact. Some of these components include:

- Year-round operations on multi-wells pads;
- Liquid gathering systems to reduce truck traffic and minimize impacts to air quality and wildlife;
- Monitoring of key wildlife species and mitigation of monitored impacts;
- Advanced emission reductions including best practices such as controlled drill rigs;
- Spatial progression of development to address specific surface and wildlife issues;
- Annual meeting and long-range planning requirements to allow for socioeconomic predictability;
- Adaptive Management to consider current and changing conditions and facilitate common-sense solutions; and

- Suspension of flank acreage until core acreage is developed and returned to a functioning habitat.

While the majority of the Company's operations in Wyoming are covered by the Pinedale ROD, provisions of the Jonah ROD similarly ensure responsible and orderly development of the Jonah field while minimizing the environmental impact:

- Annual reporting and long-range planning requirements to allow for planned mitigation and socioeconomic predictability;
- Emission reduction report to ensure air quality goals are met;
- Annual water well monitoring reports; and
- Flareless-completion technology to reduce noise, visual impacts and air emissions.

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The State of Wyoming maintains governance over some of the more traditional state-regulated matters such as individual well drilling permits, spacing and pooling, wellbore construction, as well as its own regulations on safety and environmental matters. The Wyoming Oil and Gas Conservation Commission ("WOGCC") has authorized drilling density up to one well per five acres in the Pinedale field and up to one well per ten acres in the Jonah field.

Regulations are well documented and the Company believes that it is substantially in compliance with current applicable laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on the Company. However, changes to certain existing regulations are beyond the control of the Company and could introduce uncertainty and additional costs. See Item1A "Risk Factors" for additional information regarding environmental regulations.

In December 2018 and January 2019, a portion of the federal government shut down after Congress failed to pass a continuing resolution. This shut-down included all nonessential personnel at the BLM, including BLM staff tasked with processing drilling permits and sundries. The Company has adequate inventory of approved applications for permit to drill to implement our 2019 drilling schedule, but any changes or deviations from what is approved in these permits cannot be approved during a shut-down, should another one occur, thus creating a compliance risk. In addition, such government disruptions could delay or halt the granting and renewal of the permits, approvals, and certificates required to conduct our operations. The WOGCC continues to permit and oversee drilling operations.

Mineral Leasing Act

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

Environmental and Occupational Safety and Health Matters

Surface Damage Acts

Several states, including Wyoming, and some tribal nations have enacted surface damage statutes. These laws are designed to compensate for damages caused by oil and gas development operations. Most surface damage statutes contain entry and negotiation requirements to facilitate contact between the operator and surface owners. Most also contain binding requirements for payments by the operator in connection with development operations. Costs and delays associated with surface damage statutes could impair operational effectiveness and increase development costs.

Environmental Regulations

General. The Company’s exploration, drilling and production activities from wells and oil and natural gas facilities, including the operation and construction of pipelines, plants and other facilities for transporting, processing, treating or storing oil, natural gas and other products are subject to numerous stringent federal, state and local laws and regulations relating to environmental quality, including those relating to oil spills and pollution control. These laws and regulations govern environmental cleanup standards, require permits for air, water, underground injection, solid and hazardous waste disposal and set environmental compliance criteria. In addition, state and local laws and regulations set forth specific standards for drilling wells, the maintenance of bonding requirements in order to drill or operate wells, the spacing and location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells, and the prevention and cleanup of pollutants and other matters. The U.S. Environmental Protection Agency (“EPA”) has identified environmental compliance by the energy extraction sector as one of its enforcement initiatives for fiscal years 2017-2019 and as a general matter, the oil and gas exploration and production industry has been and continues to be the subject of increasing scrutiny and regulation by environmental authorities.

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Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal fines and penalties and the imposition of injunctive relief. Accidental releases or spills may occur in the course of our operations, and we cannot be sure that we will not incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for damage to property, natural resources or persons. However, it is anticipated that, absent the occurrence of an extraordinary event, compliance with these laws and regulations will not have a material effect upon the Company’s operations, capital expenditures, earnings or competitive position.

Solid and Hazardous Waste. The Company has previously owned or leased and currently owns or leases, numerous properties that have been used for the exploration and production of oil and natural gas for many years. Although the Company utilized standard operating and disposal practices, hydrocarbons or other solid wastes may have been disposed of or released on or under such properties or on or under locations where such wastes have been taken for disposal. In addition, many of these properties are or have been operated by third parties over whom the Company has no control, nor has ever had control as to such entities’ treatment of hydrocarbons or other wastes or the manner in which such substances may have been disposed of or released. State and federal laws applicable to oil and natural gas wastes and properties have gradually become stricter over time. Under current and evolving law, it is possible the Company could be required to remediate property, including ground water, impacted by operations of the Company or by such third-party operators, or impacted by previously disposed wastes including performing remedial plugging operations to prevent future, or mitigate existing contamination.

Although oil and gas wastes generally are exempt from regulation as hazardous wastes (“Hazardous Wastes”) under the federal Resource Conservation and Recovery Act (“RCRA”) and some comparable state statutes, it is possible some wastes the Company generates presently are or in the future may be subject to regulation under RCRA and state analogs, even as non-hazardous wastes. The EPA and various state agencies have limited the disposal options for certain wastes, including Hazardous Wastes and there is no guarantee that the EPA or the states will not adopt more stringent requirements in the future. For example, in May 2016, several environmental groups filed a lawsuit in the U.S. District Court for the District of Columbia that sought to compel the EPA to review and, if necessary, revise its regulations regarding existing exemptions for exploration and production related wastes. Pursuant to a consent decree entered December 28, 2016 that settled the lawsuit, the EPA committed to propose by March 15, 2019 new regulations for the management of oil and gas wastes under RCRA Subtitle D (which relates to non-hazardous wastes), or sign a determination that a revision of existing rules is unnecessary. If the EPA proposes new rulemaking, the Consent Decree requires the EPA to take final action on such rules no later than July 15, 2021. Furthermore, certain wastes generated by the Company’s oil and natural gas operations that are currently exempt from designation as Hazardous Wastes may in the future be designated as Hazardous Wastes under RCRA or other applicable statutes, and therefore be subject to more rigorous and costly operating and disposal requirements.

In addition, current and future regulations governing the handling and disposal of Naturally Occurring Radioactive Materials (“NORM”) may affect our operations. For example, in Wyoming any waste material exceeding specified thresholds is subject to controls and guidance by the Wyoming Department of Environmental Quality Solid and Hazardous Waste Division, which determines how and where NORM wastes will be disposed of.

Hydraulic Fracturing. Many of the Company’s exploration and production operations depend on the use of hydraulic fracturing to enhance production from oil and gas wells. Hydraulic fracturing activities are typically regulated by state oil and gas commissions. The EPA has asserted federal regulatory authority over certain hydraulic-fracturing activities under the federal Safe Drinking Water Act (“SDWA”) involving the use of diesel fuels and published permitting guidance in February 2014 addressing the use of diesel in fracturing operations. Congress has periodically considered legislation to amend the SDWA to remove the exemption from permitting and regulation provided to injection for hydraulic fracturing (except where diesel is a component of the fracturing fluid) and to require the disclosure and reporting of the chemicals used in hydraulic fracturing. This type of federal legislation, if adopted, could lead to additional regulation and permitting requirements that could result in operational delays making it more difficult to perform hydraulic fracturing and increasing our costs of compliance and operating costs.

In addition, the EPA has issued guidance regarding federal regulatory authority over hydraulic fracturing using diesel under the Safe Drinking Water Act's Underground Injection Control Program. Further, in December 2016 the EPA released its final report on a wide-ranging study on the effects of hydraulic fracturing resources. While no widespread impacts from hydraulic fracturing were found, the EPA identified a number of activities and factors that may have increased risk for future impacts. Furthermore, a number of public and private studies are underway regarding the connection, if any, between the disposal of waste water associated with hydraulic fracturing and observed seismicity in the vicinity of such disposal operations. These studies and the EPA's enforcement initiative for the energy extraction sector could result in additional regulatory scrutiny that could make it difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

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In addition, some states, including Wyoming, have adopted, and other states are considering adopting, regulations that require disclosure of the chemicals in the fluids used in hydraulic fracturing or well stimulation operations. Additionally, some states, localities and local regulatory districts have adopted or have considered adopting regulations to limit, and in some case impose a moratorium on hydraulic fracturing or other restrictions on drilling and completion operations, including requirements regarding permitting, casing and cementing of wells; testing of nearby water wells; restrictions on access to, and usage of, water; and restrictions on the type of chemical additives that may be used in hydraulic fracturing operations. Although none of the Company's properties are in jurisdictions where the moratoria have been imposed, it is possible the jurisdictions where the Company's properties are located may adopt such limits or other limits on hydraulic fracturing in the future. In December 2017, BLM rescinded regulations that it previously enacted for hydraulic fracturing activities on federal lands; that rescission has been challenged by several environmental groups and states in ongoing litigation. Further, the EPA has announced an initiative under the Toxic Substances Control Act to develop regulations governing the disclosure and evaluation of hydraulic fracturing chemicals and is working on regulations for wastewater generated by hydraulic fracturing.

Finally, in some instances, the operation of underground injection wells for the disposal of waste has been alleged to cause earthquakes. In Oklahoma, for example, such issues have led to orders prohibiting continued injection or the suspension of drilling in certain wells identified as possible sources of seismic activity. Such concerns also have resulted in stricter regulatory requirements in some jurisdictions relating to the location and operation of underground injection wells. Although our operations are not located in those jurisdictions, any future orders or regulations addressing concerns about seismic activity from well injection in jurisdictions where we operate could affect our operations.

Superfund. Under the federal Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, liability, generally, is joint and several for costs of investigation and remediation and for natural resource damages, without regard to fault or the legality of the original conduct, on certain classes of persons with respect to the release into the environment of substances designated under CERCLA as hazardous substances ("Hazardous Substances"). These classes of persons, or so-called potentially responsible parties ("PRPs"), include current and certain past owners and operators of a facility where there has been a release or threat of release of a Hazardous Substance, persons who disposed of or arranged for the disposal of the Hazardous Substances found at such a facility, and in some cases the parties transporting such Hazardous Substances to the facility at issue. CERCLA also authorizes the EPA and, in some cases, third parties to take actions in response to releases and threats of releases to protect the public health or the environment and to seek to recover from the PRP the costs of such action. Although CERCLA generally exempts "petroleum" from the definition of Hazardous Substance, in the course of its operations, adulterated petroleum products containing other Hazardous Substances have been treated as Hazardous Substances in the past, and the Company has generated and will generate wastes that fall within CERCLA's definition of Hazardous Substances. The Company may also be an owner or operator of facilities on which Hazardous Substances have been released. The Company may be responsible under CERCLA for all or part of the costs to clean up facilities at which such substances have been released and for natural resource damages, as a past or present owner or operator or as an arranger. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us on or under other locations where such wastes have been taken for disposal. In addition, a portion of these properties may have been operated by third parties whose treatment and disposal or release of wastes was not under our control. Many states have comparable laws imposing liability on similar classes of persons for releases, including for releases of materials that may not be included in CERCLA's definition of Hazardous Substances. To its knowledge, the Company has not been named a PRP under CERCLA (or any comparable state law) nor have any prior owners or operators of its properties been named as PRPs related to their ownership or operation of such property.

National Environmental Policy Act. The federal National Environmental Policy Act provides that, for federal actions significantly affecting the quality of the human environment, the federal agency taking such action must prepare an Environmental Assessment (“EA”) or an environmental impact statement (“EIS”). In the EIS, the agency is required to evaluate alternatives to the proposed action and the environmental impacts of the proposed action and of such alternatives. Actions of the Company, such as drilling on federal lands, to the extent the drilling requires federal approval, may trigger the requirements of the National Environmental Policy Act, including the requirement that an EA or EIS be prepared. The requirements of the National Environmental Policy Act may result in increased costs, significant delays and the imposition of restrictions or obligations on the Company’s activities, including but not limited to the restricting or prohibiting of drilling.

Oil Pollution Act. The Oil Pollution Act of 1990 (“OPA”), which amends and augments oil spill provisions of the Clean Water Act (“CWA”), imposes certain duties and liabilities on certain “responsible parties” related to the prevention of oil spills and damages resulting from such spills in or threatening United States waters or adjoining shorelines. A liable “responsible party” includes the owner or operator of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge or, in the case of offshore facilities, the lessee or permittee of the area in which a discharging facility is located. OPA assigns liability, which generally is joint and several, without regard to fault, to each liable party for oil removal costs and for a variety of public and private damages. Although defenses and limitations exist to the liability imposed by OPA, they are limited. In the event of an oil discharge or substantial threat of discharge, the Company could be liable for costs and damages.

Clean Air Act. The Clean Air Act ("CAA") regulates emissions of six criteria pollutants from stationary and mobile sources and establishes National Ambient Air Quality Standards ("NAAQS") for the pollutants of concern. The CAA is a federal law, but states, tribes and local governments do much of the work to develop EPA-approved plans to achieve these standards and meet the CAA's requirements. Federal and state laws generally require new and modified sources of air pollutants to obtain permits prior to commencing construction, which may require, among other things, stringent emission controls. Administrative agencies can bring actions for failure to comply with air pollution regulations or permits and generally enforce compliance through administrative, civil or criminal enforcement actions, which may result in fines, injunctive relief and imprisonment.

The New Source Performance Standards ("NSPS") and National Emission Standards for Hazardous Air Pollutants ("NESHAP") programs under the CAA impose specific requirements affecting the oil and gas industry under both programs for compressors, controllers, dehydrators, storage tanks, natural gas processing plants, completions and certain other equipment. Periodic review and revision of these rules by federal and state agencies may require changes to our operations, including possible installation of new equipment to control emissions. We continuously evaluate the effect of new rules on our business.

In May 2016, the EPA finalized rules to reduce methane and volatile organic compound ("VOC") emissions from new, modified or reconstructed sources in the oil and natural gas sector; however, in September 2018, under a new administration, the EPA proposed amendments that would relax requirements of the rules. Similarly, in September 2018, the BLM issued a rule that relaxes or rescinds certain requirements of regulations it had previously enacted to reduce methane emissions from venting, flaring, and leaks during oil and gas operations on public lands; California and New Mexico have challenged the new rule in ongoing litigation. In addition, in April 2018, a coalition of states filed a lawsuit in federal district court aiming to force the EPA to establish guidelines for limiting methane emissions from existing sources in the oil and natural gas sector; that lawsuit is pending. Several states are pursuing similar measures to regulate emissions of methane from new and existing sources within the oil and natural gas source category. In addition, in May 2016, the EPA finalized rules regarding criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and gas industry. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting requirements and cause major delays in construction, effectively depressing new development. Compliance with these and other air pollution control and permitting requirements has the potential to delay the development of oil and natural gas projects and increase our costs of development, which could be significant.

Clean Water Act. The Clean Water Act ("CWA") and analogous state laws restrict the discharge of pollutants, including produced waters and other oil and natural gas wastes, into waters of the United States, a term broadly defined to include, among other things, certain wetlands. Under the Clean Water Act, permits must be obtained for the discharge of pollutants into waters of the United States. The CWA provides for administrative, civil and criminal penalties for unauthorized discharges, both routine and accidental, of pollutants and of oil and hazardous substances. It imposes substantial potential liability for the costs of removal or remediation associated with discharges of oil or hazardous substances. State laws governing discharges to water also provide varying civil, criminal and administrative penalties and impose liabilities in the case of a discharge of petroleum or its derivatives, or other hazardous substances, into state waters. In addition, the EPA has promulgated regulations that may require permits to discharge storm water runoff, including discharges associated with construction activities.

The CWA also prohibits the discharge of fill materials to regulated waters including wetlands without a permit. In September 2015, the EPA and the Army Corps of Engineers ("Corps") issued new rules defining the scope of the EPA's and the Corps' jurisdiction over wetlands (the "Clean Water Rule"). The Clean Water Rule was stayed nationwide by the U.S. Sixth Circuit Court of Appeals, but on January 22, 2018, the U.S. Supreme Court ruled that jurisdiction to hear challenges to the rule lies with the federal district courts, and the Sixth Circuit's stay was dissolved in February 2018. On July 27, 2017, the EPA published a proposed rule to rescind the Clean Water Rule and re-codify the regulatory text that existed prior to 2015 defining the "waters of the United States," for which the EPA and the U.S. Department of the Army established a non-regulatory docket to solicit written recommendations for the rulemaking, which closed on November 28, 2017. On February 6, 2018, the EPA and the Corps finalized a two-year postponement of the effective date of the Clean Water Rule to February 6, 2020. On August 16, 2018, the U.S. District Court for the District of South Carolina issued a nationwide injunction against EPA's and the Corps' postponement of the Clean Water Rule, making the rule effective in 26 states, certain of which have asked the U.S. District Court for the Southern District of Texas to postpone the rule nationwide. To the extent the Clean Water Rule is enforced in jurisdictions in which we operate or a replacement rule expands the scope of the Clean Water Act's jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. In December 2018, EPA released revisions to the definition of WOTUS, specifically excluding "ephemeral" features that exist only during precipitation events and removing any groundwater features. These revisions are anticipated for finalization in 2019. Until that time, regulations are being implemented as they were prior to August 2015.

Also, in 2016, the EPA finalized new wastewater pretreatment standards that prohibit onshore unconventional oil and gas extraction facilities from sending wastewater to publicly-owned treatment works, permitting several years until compliance will be enforced. This pending restriction of disposal options for hydraulic fracturing waste and other changes to CWA requirements may result in increased costs.

Endangered Species Act. The Endangered Species Act ("ESA") was established to protect endangered and threatened species. Pursuant to that act, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act, and special protections are provided to bald and golden eagles under the Bald and Golden Eagle Protection Act. The Company conducts operations on federal and other oil and natural gas leases that have species, such as raptors, that are listed and species, such as sage grouse, that could be listed as threatened or endangered under the ESA. In the case of sage grouse, in October 2017, the U.S. Fish and Wildlife Service announced the beginning of a scoping process to solicit public comments on Greater Sage-Grouse land management that could warrant land plan use amendments relating to the sage grouse. On February 11, 2016, the U.S. Fish and Wildlife Service published a final policy which alters how it identifies critical habitat for endangered and threatened species. A critical habitat designation could result in further material restrictions to federal and private land use and could delay or prohibit land access or development. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service is required to make listing decisions and critical habitat designations where necessary for over 250 species. The U.S. Fish and Wildlife Service issued a 7-Year National Listing Workplan in September 2016. However, on July 25, 2018, the U.S. Fish and Wildlife Service proposed three revisions to regulations regarding critical habitat designation, interagency cooperation, and protection of threatened species that it believes are necessary to address industry and landowner concerns. The U.S. Department of the Interior also issued an opinion on December 22, 2017 that would narrow certain protections afforded to migratory birds pursuant to the MBTA. In response to this opinion, two separate lawsuits were filed on May 24, 2018 in the U.S. District Court for the Southern District of New York challenging the Department of the Interior's interpretation of the MBTA. On September 5, 2018, eight states also filed suit in the U.S. District Court for the Southern District of New York on the relevant issue. The identification or designation of previously unprotected species as threatened or endangered in areas where our operations are conducted could cause us to incur increased costs arising from species protection measures or could result in limitations on our development activities that could have an adverse impact on our ability to develop and produce reserves. If we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our leases.

Climate Change Legislation. More stringent laws and regulations relating to climate change and greenhouse gases ("GHGs"), including methane and carbon dioxide, may be adopted and could cause the Company to incur material expenses in complying with them. In the absence of comprehensive federal legislation on GHG emission control, the EPA attempted to require the permitting of GHG emissions. Although the Supreme Court struck down the permitting requirements as applicable to GHG emissions, it upheld the EPA's authority to control GHG emissions when a permit is required due to emissions of other pollutants. The EPA has established GHG reporting requirements for sources in the petroleum and natural gas industry, requiring those sources to monitor, maintain records on, and annually report their GHG emissions. The Company has submitted all required annual reports to date. Although the rule does not limit the amount of GHGs that can be emitted, it could require us to incur significant costs to monitor, keep records of, and report GHG emissions associated with our operations.

In addition, Congress has from time to time considered adopting legislation to reduce emissions of GHGs, and a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs. Cap and trade programs typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. On an international level, the United States was one of 175 countries to sign an international climate change agreement in Paris, France that requires member countries to set their own GHG emission reduction goals beginning in 2020. However, on June 1, 2017, President Trump announced that the United States will withdraw from the Paris Agreement, and on August 4, 2017, the U.S. State Department officially informed the United Nations of its intent to withdraw from the Paris Agreement as of November 4, 2020 unless the agreement is renegotiated. Various states and local governments have vowed to continue to enact regulations to achieve the goals of the Paris Agreement.

Any legislation or regulatory programs to reduce GHG emissions could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations. Moreover, incentives to conserve energy or use alternative energy sources as a means of addressing climate change could reduce demand for the oil and natural gas we produce. In addition, parties concerned about the potential effects of climate change have directed their attention at sources of funding for energy companies, which has resulted in certain financial institutions, funds and other sources of capital, restricting or eliminating their investment in oil and natural gas activities. Finally, it should be noted that many scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events. If any such effects were to occur, they could adversely affect or delay demand for the oil or natural gas produced by our customers or otherwise cause us to incur significant costs in preparing for or responding to those effects.

Worker Safety. The Occupational Safety and Health Act ("OSHA") and analogous state laws regulate the protection of the safety and health 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. For example, under a new OSHA standard limiting respirable silica exposure, the oil and gas industry must implement engineering controls and work practices to limit exposures below the new limits by June 23, 2021. Failure to comply with OSHA requirements can lead to the imposition of penalties. In December 2015, the U.S. Departments of Justice and Labor announced a plan to more frequently and effectively prosecute worker health and safety violations, including enhanced penalties.

The Company believes that it is in substantial compliance with current applicable environmental and occupational health and safety laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on the Company.

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Employees

As of December 31, 2018, the Company had 151 full-time employees, including officers. The Company believes that its relationship with its employees is satisfactory.

Seasonality and Cyclicality

Seasonal weather conditions and lease stipulations can limit the drilling and producing activities and other operations in the areas in which the Company operates. These seasonal conditions can pose challenges for meeting the well drilling objectives and increase competition for equipment, supplies and personnel, which could lead to shortages and increase costs or delay operations. For example, the Company's operations may be impacted by ice and snow in the winter and by electrical storms and high temperatures in the spring and summer, as well as by wild fires in the fall.

The demand for natural gas typically decreases during the summer months and increases during the winter months. Seasonal anomalies sometimes lessen this fluctuation. In addition, certain natural gas consumers utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer, which can also lessen seasonal demand fluctuations. As a corollary, the demand for our products can be impacted by weather in the western United States from temperature fluctuations outside of normal ranges, moisture levels in the Pacific Northwest to the extent it impacts hydroelectric power generation, and more broadly across the United States when there are unusual cold events or lack of winter weather.

Competition

The oil and gas industry is intensely competitive, and we compete with other companies in our industry that have more extensive resources than we do or that may have other competitive advantages or disadvantages. We compete with other companies in the acquisition of properties, in the search for and development of reserves, in the production and sale of natural gas and crude oil, and for the labor and equipment required to conduct our operations. Our competitors include major oil and natural gas companies, other independent oil and natural gas companies, and individual producers and operators.

Principal Executive Offices

The Company is incorporated under the laws of Yukon, Canada, with headquarters in Englewood, Colorado. The principal executive offices are located at 116 Inverness Drive East, Suite 400, Englewood, Colorado. The main telephone number is (303) 708-9740.

Item 1A. Risk Factors.

An investment in our common stock involves certain risks. If any of the following key risks were to occur, it could have a material adverse effect on our financial position, results of operations, and cash flows. In any such circumstance and others described below, the trading price of our securities could decline and investors could lose part or all of their investment.

We have significant indebtedness. Our level of indebtedness could adversely affect our business, results of operations, and financial condition. If we are unable to comply with the financial and non-financial covenants governing our indebtedness or obtain waivers of any defaults that occur with respect to our indebtedness, or amend, replace or refinance any or all of the agreements governing our indebtedness and/or otherwise secure additional capital, we may be unable to meet our expenses and debt obligations.

At February 28, 2019, we had the following obligations outstanding under our Revolving Credit Facility, our Term Loan Facility (as defined in Note 6), our Second Lien Notes, 2022 Notes and our 2025 Notes:

- $41 million due January 12, 2022 under the Revolving Credit Facility;
- $975 million due April 12, 2024 under the Term Loan Facility;
- $572 million due July 12, 2024 with respect to the Second Lien Notes;
- $150 million due April 12, 2022 with respect to the 2022 Notes; and
- $225 million due April 12, 2025 with respect to the 2025 Notes.

Our indebtedness affects our operations in several ways, including:

- requiring us to dedicate a substantial portion of our cash flow from operations to service our existing debt, thereby reducing the cash available to finance our operations and other business activities, and limiting our flexibility in planning for or reacting to changes in our business and the industry in which we operate;
- increasing our vulnerability to economic downturns and adverse developments in our business;
- limiting our ability to access the capital markets to raise capital on favorable terms or to obtain additional financing for working capital, capital expenditures or acquisitions or to refinance existing indebtedness;
- placing restrictions on our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations;

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- placing us at a competitive disadvantage relative to competitors with lower levels of indebtedness in relation to their overall size or less restrictive terms governing their indebtedness;
- limiting our ability to deduct our net interest expense; and
- making it more difficult for us to satisfy our obligations under our existing indebtedness and increasing the risk that we may default on our debt obligations.

Our ability to meet our expenses and debt service obligations will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors. We will not be able to control many of these factors, such as economic conditions and governmental regulation. We depend on our Revolving Credit Facility for future capital and liquidity needs, because we use operating cash flows for investing activities and borrow as needed. We cannot be certain that our cash flow or liquidity will be sufficient to allow us to pay the principal and interest on our outstanding indebtedness and meet our other obligations. If we do not have enough money, we may be required to refinance all or part of our existing indebtedness, sell assets, borrow more money or raise equity. We may not be able to refinance our existing indebtedness, sell assets, borrow more money or raise equity on terms acceptable to us, if at all. Our ability to comply with the financial and other restrictive covenants in our indebtedness will be affected by the levels of cash flow from our operations and future events and circumstances beyond our control. Failure to comply with these covenants would result in an event of default under our indebtedness, and such an event of default could materially and adversely affect our business, financial condition and results of operations.

There are covenants in the agreements governing our indebtedness. In many instances, a default under one of the agreements governing our indebtedness can, if not cured or waived, result in a default under certain of our other indebtedness agreements. A default on our obligations and/or an acceleration of our indebtedness by our lenders or noteholders, as applicable, would have a material adverse impact on our business, financial condition, results of operations, cash flows, and the trading price of our securities.

Under the Fourth Amendment to the Revolving Credit Facility, Ultra Resources is required to maintain (i) an interest coverage ratio of 2.50 to 1.00; (ii) a current ratio, including the unused portion of the Revolving Credit Facility, of 1.00 to 1.00; (iii) a net leverage ratio of 4.50 to 1.00 as of December 31, 2018, 4.75 to 1.00 as of March 31, 2019 through June 30, 2019, 4.90 to 1.00 as of September 30, 2019 through June 30, 2020, 4.50 to 1.00 as of September 30, 2020, and 4.25 to 1.00 as of December 31, 2020 and each other fiscal quarter end thereafter; and (iv) after the Company has obtained investment grade rating, an asset coverage ratio of 1.50 to 1.00. At December 31, 2018, we were in compliance with all of our debt covenants under our Revolving Credit Facility. Should the independent auditor conclude that a going concern modification explanatory paragraph would be required as of an annual audit period, such an item would be deemed a covenant violation under the Revolving Credit Facility and the Term Loan Facility. A violation of this covenant can become an event of default under our debt agreements and result in the acceleration of all of our indebtedness.

If our lenders or our noteholders accelerate the payment of amounts outstanding under our Revolving Credit Facility, the Term Loan Facility, the Second Lien Notes or the Unsecured Notes, respectively, we do not currently have sufficient liquidity to repay such indebtedness and would need additional sources of capital to do so. We could attempt to obtain additional sources of capital from asset sales, public or private issuances of debt, equity or equity-linked securities, debt for equity swaps, or any combination thereof. However, we cannot provide any assurances that we will be successful in obtaining capital from such transactions on acceptable terms, or at all, and if we were unable to obtain sufficient additional capital to repay the outstanding indebtedness and sufficient liquidity to meet our operating needs, it may be necessary for us to seek protection from creditors under chapter 11 or the Canadian Bankruptcy and Insolvency Act, or an involuntary petition for bankruptcy may be filed against us in the U.S. or in Canada.

The borrowing base under our Revolving Credit Facility may be reduced, which could limit us in the future. In addition, the liquidity under our Revolving Credit Facility may be more limited than the borrowing base availability due to the consolidated net leverage financial covenant.

The borrowing base under our Revolving Credit Facility is currently $1.3 billion, and lender commitments under our Revolving Credit Facility are $325.0 million based on the recent borrowing base redetermination. The borrowing base is redetermined semi-annually under the terms of our Revolving Credit Facility on April 1 and October 1. The April 1, 2019 redetermination was accelerated by the Company and has been completed as of the date of this filing. The next regularly scheduled redetermination is October 1, 2019. In addition, either we or the lenders may request an interim redetermination twice a year or in conjunction with certain acquisitions or sales of oil and gas properties. Our borrowing base may decrease as a result of lower commodity prices, operating difficulties, declines in reserves, lending requirements or regulations, the issuance of new indebtedness, or for any other reason. In the event of a decrease in our borrowing based due to declines in commodity prices or otherwise, our ability to borrow under the Revolving Credit Facility may be limited and we could be required to pay indebtedness in excess of the redetermined borrowing base. In addition, we may be unable to access the equity or debt capital markets, including the market for senior unsecured notes, to meet our obligations, including any such debt repayment obligations.

Moreover, while our current borrowing base and the amount outstanding under the Revolving Credit Facility may indicate sufficient liquidity, the amount that we may borrow under the Revolving Credit Facility is governed by compliance with the consolidated net leverage covenant as discussed above. The calculation of this covenant may result in the Company having less effective liquidity, thereby negatively impacting the Company’s ability to operate in an unencumbered manner and may create a risk of continuing as a going concern.

Failure to maintain the continued listing standards of NASDAQ could result in delisting of our common shares, which could negatively impact the market price and liquidity of our common shares and our ability to access the capital markets.

Our common shares are listed on the NASDAQ Global Select Market ("NASDAQ") and the continued listing of our common shares on NASDAQ is subject to our ability to comply with NASDAQ's continued listing requirements, including, among other things, the requirement to hold an annual shareholders' meeting and the minimum closing bid price requirement of $1.00 per common share.

On January 2, 2019, we received written notice from the Listing Qualifications Department of NASDAQ notifying us that we no longer comply with NASDAQ Listing Rule 5620(a) due to the Company's failure to hold an annual meeting of shareholders within twelve months of the end of the Company's fiscal year ended December 31, 2017. On February 1, 2019, we submitted to NASDAQ a plan to regain compliance with the annual shareholders meeting requirement by holding a combined annual meeting of shareholders for 2018 and 2019 on May 22, 2019, and NASDAQ accepted our plan of compliance.

In addition, on January 29, 2019, we received written notice from the Listing Qualifications Department of NASDAQ notifying us that our common shares closed below the $1.00 per share minimum bid price required by NASDAQ Listing Rule 5450(a)(1) for 30 consecutive business days and that we have a period of 180 calendar days in which to regain compliance.

We are actively monitoring the bid price of our common shares and considering options to regain compliance with the minimum bid price requirement. If we are unable to regain compliance, however, any delisting from NASDAQ could result in even further reductions in our price per common share, substantially limit the liquidity of our common shares, and materially adversely affect our ability to raise capital or pursue strategic restructuring, refinancing or other transactions on acceptable terms, or at all. Delisting from the NASDAQ could also have other negative results, including the potential loss of institutional investor interest and fewer business development opportunities.

There is no assurance that we will continue to maintain compliance with NASDAQ continued listing standards. Our business has been and may continue to be affected by worldwide macroeconomic factors, which include uncertainties in the credit and capital markets as well as with respect to commodity prices. External factors that affect our share price, such as liquidity requirements of our investors, as well as our performance, could impact our market capitalization, revenue and operating results, which, in turn, affect our ability to comply with the NASDAQ's listing standards. The NASDAQ has the ability to suspend trading in our common shares or remove our common shares from listing on the NASDAQ if, in the opinion of NASDAQ: (a) our financial condition and/or operating results appear to be unsatisfactory; (b) it appears that the extent of public distribution or the aggregate market value of our common shares has become so reduced as to make further dealings on the exchange inadvisable; (c) we have sold or otherwise disposed of our principal operating assets, or have ceased to be an operating company; (d) we have failed to comply with our listing agreements with the exchange; or (e) any other event shall occur or any condition shall exist which makes further dealings on the exchange unwarranted.

If we cannot obtain sufficient capital when needed, we will not be able to continue with our business strategy.

Our business strategy has historically included maintaining a portfolio of properties that provide long-term, profitable growth through development in areas that support sustainable, lower-risk, repeatable, high-return drilling projects. In the future, we may not be able to obtain financing in sufficient amounts or on acceptable terms when needed, which could adversely affect our operating results and prospects. If we cannot raise the capital required to implement our historical business strategy, we may be required to curtail operations, which could adversely affect our financial condition and results of operations.

Our substantial indebtedness, liquidity concerns, the credit ratings assigned to our debt by independent credit rating agencies and historical emergence from bankruptcy in 2017 could adversely affect our business and relationships.

Our substantial indebtedness, liquidity concerns, the credit ratings assigned to our debt by independent credit rating agencies and our historical emergence from chapter 11 bankruptcy proceedings in 2017 could adversely affect our business and relationships with customers, employees, and suppliers. Due to uncertainties, many risks exist, including the following:

- key suppliers could terminate their relationship or require financial assurances or enhanced performance;
- the ability to renew existing contracts and compete for new business may be adversely affected;
- the ability to attract, motivate, and/or retain key executives and employees may be adversely affected;
- employees may be distracted from performance of their duties or more easily attracted to other employment opportunities; and
- competitors may take business away from us, and our ability to attract and retain customers may be negatively impacted.

The occurrence of one or more of these events could have a material and adverse effect on our operations, financial conditions, and reputation. We cannot assure you that having been subject to bankruptcy protections will not adversely affect our operations in the future.

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Transfers or issuances of our equity may impair our ability to utilize our income tax net operating loss carryforwards in future years.

Under federal income tax law, a corporation is generally permitted to deduct from taxable income net operating losses carried forward from prior years. We have U.S. federal net operating loss carryforwards of approximately $2.2 billion as of December 31, 2018. Our ability to utilize our net operating loss carryforwards to offset future taxable income and to reduce federal income tax liability may be substantially limited if we experience an “ownership change,” as defined in section 382 of the U.S. Internal Revenue Code of 1986, as amended (the “Code”), which could have a negative impact on our financial position and results of operations. Generally, there is an “ownership change” if one or more shareholders owning 5% or more of a corporation’s common stock have aggregate increases in their ownership of such stock of more than 50 percentage points over the prior three-year period. An “ownership change” occurred when our chapter 11 plan of reorganization became effective. A further “ownership change” is possible now that we have emerged from chapter 11. Under section 382 of the Code, absent an applicable exception, if a corporation undergoes an “ownership change,” the amount of its pre-ownership change net operating losses that may be utilized to offset future taxable income generally will be subject to an annual limitation equal to the value of its stock immediately prior to the ownership change multiplied by the long-term tax-exempt rate, plus an additional amount calculated based on certain “built in gains” in our assets that may be deemed to be realized within a 5-year period following any ownership change. The ownership change that occurred as a result of our exit from chapter 11 proceedings should not materially limit our ability to utilize our net operating loss carryforwards, but it may be affected by future ownership changes, if any. In addition, under the tax reform bill commonly known as Tax Cuts and Jobs Act (the “Tax Act”), which was signed into law on December 22, 2017, (i) the amount of post-2017 net operating losses that we are permitted to deduct in any taxable year is limited to 80% of our taxable income in such year, where taxable income is determined without regard to the net operating loss deduction itself, and (ii) post-2017 net operating losses cannot be carried back to prior taxable years. There can be no assurance that we will be able to utilize our federal income tax net operating loss carry-forwards to offset future taxable income.

Our operations could be adversely affected if we fail to maintain required bonds.

Federal and state laws require bonds or cash deposits to secure our obligations with respect to various parts of our operations. Our failure to maintain, or inability to acquire, bonds that are required by state and federal law would have a material adverse effect on us. That failure could result from a variety of factors including: (i) our failure to comply with rules and regulations of federal and state governmental agencies, including the BLM, (ii) the lack of availability of bonding, higher expense or unfavorable market terms of new bonds; (iii) and the exercise by third-party bond issuers of their right to refuse to renew the bonds. If we fail to maintain required bonds, our production may significantly decrease, which would significantly decrease our already constrained cash flow.

Liquidity concerns could result in a downgrade in our debt ratings which could restrict our access to, and negatively impact the terms of, current or future financings or trade credit.

Our ability to obtain financings and trade credit and the terms of any financings or trade credit is, in part, dependent on the credit ratings assigned to our debt by independent credit rating agencies. We cannot provide assurance that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. Factors that may impact our credit ratings include debt levels, planned asset purchases or sales and near-term and long-term production growth opportunities, liquidity, asset quality, cost structure, product mix and commodity pricing levels. A ratings downgrade could adversely impact our ability to access financings or trade credit, increase our borrowing costs and potentially require us to post letters of credit for certain obligations.

We cannot control the future price of oil and natural gas and sustained periods of low prices could hurt our profitability and financial condition and could impair our ability to grow our business or to perform the obligations in our agreements, including the agreements governing our indebtedness.

Sustained periods of low commodity prices will adversely affect our operations and financial condition. Our revenues, profitability, liquidity, ability to raise capital for our business, future growth, ability to operate, develop and explore our properties, and the carrying value of our properties depend heavily on prevailing prices for oil and natural gas.

Natural gas comprised approximately 95% of our total production and 81% of our consolidated revenue for the year ended December 31, 2018 and represented 95% of our total proved reserves as of December 31, 2018. Historically, natural gas prices have been highly volatile, including in the Rocky Mountain region of the United States where the vast majority of our natural gas is produced. Prices have been affected by actions of federal, state and local governments and agencies, foreign governments, national and international economic and political conditions, levels of consumer demand, weather conditions, domestic and foreign supply of oil and natural gas, proximity and capacity of gas pipelines and other transportation facilities, the price and availability of equipment, materials and personnel to conduct operations, and the price and availability of alternative fuels. These external factors and the volatile nature of the energy markets make it difficult to estimate future prices of natural gas. Any substantial or extended decline in the price of natural gas will have a material adverse effect on our financial condition and results of operations, including reduced cash flow and borrowing capacity, and lower proved reserves. Price volatility also makes it difficult to budget for and project the return on potential acquisitions and development and exploration projects, and sustained lower gas prices have caused and may, in the future continue to cause, us or the operators of properties in which we have ownership interests to curtail projects and limit or suspend drilling, completion or even production activities.

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Crude oil comprised approximately 5% of our total production and 17% of our consolidated revenue for the year ended December 31, 2018 and represented 5% of our total proved reserves as of December 31, 2018. Crude oil prices declined substantially in the second half of 2014, with sustained lower prices continuing throughout 2015, 2016, and 2017, and prices remaining volatile during the year ended December 31, 2018. In the future, crude oil prices may remain at current levels or fall to lower levels. If crude oil prices remain at current levels or fall to lower levels, this will adversely affect our crude oil operations and our financial condition. Most of the production from our Uinta Basin properties was crude oil.

In addition, because we are significantly leveraged, a substantial decrease in our revenue due to low commodity prices is currently impairing and may in the future continue to impair our ability to satisfy payment obligations on our indebtedness and reduce funds available for operations and future business opportunities.

A substantial or extended decline in oil and natural gas prices may continue indefinitely, and may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations, our debt repayment and service obligations, and our financial commitments.

The price we receive for our oil and natural gas heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile and we expect this volatility to continue for the foreseeable future. For example, during the period from January 1, 2014 to December 31, 2018, NYMEX West Texas Intermediate oil prices ranged from a high of $107.31 per Bbl to a low of $27.57 per Bbl. Average daily prices for NYMEX Henry Hub gas ranged from a high of $5.30 per MMBtu to a low of $1.65 per MMBtu during the same period. Additionally, the price differential for natural gas can also vary significantly. Over this same period, average monthly prices for NwRox ranged from a high of $6.92 per Mmbtu to a low of $1.50 per Mmbtu. This near-term volatility may affect future prices in 2019 and beyond. The volatility of the energy markets makes it difficult to predict future oil and natural gas price movements with any certainty.

The prices we receive for our production and the levels of our production depend on numerous factors beyond our control. These factors include the following:

- worldwide and regional economic conditions impacting the global supply and demand for oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions in or affecting other oil and natural gas-producing countries;
- 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;
- weather conditions and natural disasters;
- government policies to discourage use of fuels that emit “greenhouse gases” (“GHGs”) and encourage use of alternative energy;
- domestic, local and foreign governmental regulations and taxes;
- speculation as to the future price of oil and natural gas 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;
- the availability of drilling rigs and completion equipment; and

- the overall economic environment.

Substantially all of our production is currently sold at market-based prices. Lower oil and natural gas prices will reduce our cash flows, borrowing ability and the present value of our reserves. Lower oil and natural gas prices will reduce the amount of oil and natural gas that we can produce economically. Substantial decreases in oil and natural gas prices could render uneconomic a significant portion of our identified drilling locations, and, may cause us to make significant downward adjustments to our estimated proved reserves or to be unable to claim proved undeveloped reserves at all. If oil and natural gas prices remain at current levels or experience a substantial or extended decline from current levels, our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures will be materially and adversely affected.

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Our reserve estimates may turn out to be incorrect if the assumptions upon which these estimates are based are inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

There are numerous uncertainties inherent in estimating quantities of proved reserves and projected future rates of production and timing of development expenditures, including many factors beyond our control. The reserve data and standardized measures set forth herein represent only estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates of different engineers often vary. In addition, drilling, testing and production data acquired subsequent to the date of an estimate may justify revising such estimates. Accordingly, reserve estimates are often different from the quantities of oil, natural gas and NGLs that are ultimately recovered. Further, the estimated future net revenues from proved reserves and the present value thereof are based upon certain assumptions, including geologic success, the timing and identification of future drilling locations, commodity prices, future production levels, costs and the ability to finance future development that may not prove correct over time. Predictions of future production levels, development schedules (particularly with regard to non-operated properties), participation of joint working interest owners on projects, commodity prices and future operating costs are subject to great uncertainty, and the meaningfulness of such estimates is highly dependent upon the accuracy of the assumptions upon which they are based.

The present value of net proved reserves included in this report should not be considered as the market value of the reserves attributable to our properties. In accordance with SEC requirements, we base the present value, discounted at 10%, of the pre-tax future net cash flows attributable to our net proved reserves on the average oil and natural gas prices during the 12-month period before the ending date of the period covered by this report determined as an un-weighted, arithmetic average of the first-day-of-the-month price for each month within such period, adjusted for quality and transportation fees. The costs to produce the reserves remain constant at the costs prevailing on the date of the estimate. Actual current and future commodity prices and costs may be materially higher or lower, and higher future costs and/or lower future commodity prices may impact whether development of our reserves in the future occurs as scheduled or at all. In addition, the 10% discount factor, which the SEC requires us to use in calculating our discounted future net revenues for reporting purposes, may not be the most appropriate discount factor based on our cost of capital from time to time and/or the risks associated with our business.

Our producing properties are located in the Green River Basin in southwest Wyoming, making us vulnerable to risks associated with operating in a single geographic area.

All of our producing properties are geographically concentrated in the Green River Basin in southwest Wyoming. At December 31, 2018, all of our total estimated proved reserves were attributable to properties located in this area. As a result of this concentration, we are disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, availability of equipment and personnel, water shortages or other drought-related conditions or interruption of the processing or transportation of oil, natural gas or NGLs.

Competitive industry conditions may negatively affect our ability to conduct operations.

We compete with numerous other companies in virtually all facets of our business. Our competitors in development, exploration, acquisitions and production include major integrated oil and natural gas companies as well as numerous independents, including many that have significantly greater resources. Therefore, competitors may be able to pay more for desirable leases and evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources permit. We also compete for the materials, equipment and services that are necessary for the exploration, development and operation of our properties. Our ability to increase reserves in the future will be dependent on our ability to select and acquire suitable prospects for future exploration and development.

Factors that affect our ability to compete in the marketplace include:

- our access to the capital necessary to drill and complete wells and acquire properties;
- our ability to acquire and analyze seismic, geological and other information relating to a property;
- our ability to attract and retain the personnel necessary to properly evaluate seismic and other information relating to a property;
- our ability to procure materials, equipment and services required to explore, develop and operate our properties;
- our ability to comply with administrative, regulatory and other governmental requirements; and
- our ability to access pipelines, and the locations of facilities used to produce and transport oil and natural gas production.

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Factors beyond our control affect our ability to effectively market production and may ultimately affect our financial results.

The ability to market oil and natural gas depends on numerous factors beyond our control. These factors include:

- the extent of domestic production and imports of oil and natural gas;
- the availability of pipeline, rail and refinery capacity, including facilities owned and operated by third parties;
- the availability of a market for our oil and natural gas production;
- the availability of satisfactory transportation arrangements for our oil and natural gas production;
- the proximity of natural gas production to natural gas pipelines;
- the effects of inclement weather;
- the demand for oil and natural gas by utilities and other end users;
- the availability of alternative fuel sources;
- state and federal regulations of oil and natural gas marketing and transportation; and
- federal regulation of natural gas sold or transported in interstate commerce.

Because of these factors and other factors beyond our control, we may be unable to market all of the oil and natural gas that we produce or obtain favorable prices for such production.

Our business relies on certain key personnel.

Our management believes that our continued success will depend to a significant extent upon the efforts and abilities of certain of our key personnel. The loss of the services of any of these key personnel could have a material adverse effect on our business. We do not maintain “key man” life insurance on any of our officers or other employees.

Any derivative transactions we enter into may limit our gains and expose us to other risks such as taxes and royalties.

We may enter into financial derivative transactions from time to time to manage our exposure to commodity price risks. These transactions limit our potential gains if commodity prices rise above the levels established by our derivative transactions. These transactions may also expose us to other risks of financial losses, for example, if our production is less than we anticipated at the time we entered into a derivative instrument or if a counterparty to our derivative instruments fails to perform its obligations under a derivatives transaction. We pay royalties and taxes based on physical production; therefore, if we have utilized derivative transactions on a high percentage of our forecast production, we may have royalty and tax burdens that are significantly higher than the derivative price settled for that month’s production.

Legislation and regulations related to derivative contracts could have an adverse impact on our ability to hedge risks associated with our business.

Title VII of the Dodd–Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”) establishes federal oversight and regulation of over-the-counter (“OTC”) derivatives and requires the U.S. Commodity Futures Trading Commission (the “CFTC”) and the SEC to enact further regulations affecting derivative contracts, including the derivative contracts we use to hedge our exposure to price volatility through the OTC market.

Although the CFTC and the SEC have issued final regulations in certain areas, final rules in other areas and the scope of relevant definitions and/or exemptions still remain to be finalized. In one of its rulemaking proceedings still pending under the Dodd-Frank Act, the CFTC issued on November 5, 2013, a proposed rule imposing position limits for certain futures and option contracts in various commodities (including natural gas) and for swaps that are their economic equivalents. Certain specified types of hedging transactions are exempt from these position limits, provided that such hedging transactions satisfy the CFTC's requirements for "bona fide hedging" transactions or positions. Similarly, the CFTC has issued a proposed rule on margin requirements for swap transactions, which proposes an exemption for commercial end-users, entering into uncleared swaps in order to hedge commercial risks affecting their business, from any requirement to post margin to secure such swap transactions. In addition, the CFTC has issued a final rule authorizing an exception for commercial end-users using swaps to hedge their commercial risks from the otherwise applicable mandatory obligation under the Dodd-Frank Act to clear all swap transactions through a registered derivatives clearing organization and to trade all such swaps on a registered exchange. The Dodd-Frank Act also imposes recordkeeping and reporting obligations on counterparties to swap transactions and other regulatory compliance obligations. All of the above regulations could increase the costs to us of entering into financial derivative transactions to hedge or mitigate our exposure to commodity price volatility and other commercial risks affecting our business.

While it is not possible at this time to predict when the CFTC will issue final rules applicable to position limits or margin requirements, depending on the Company's ability to satisfy the CFTC's requirements for the various exemptions available for a commercial end-user using swaps to hedge or mitigate its commercial risks, these rules and regulations may require us to comply with position limits, margin requirements and with certain clearing and trade-execution requirements in connection with our financial derivative activities. The Dodd-Frank Act may require our current counterparties to post additional capital as a result of entering into uncleared financial derivatives with us, which could increase the cost to us of entering into such derivatives. The Dodd-Frank Act may also require our current counterparties to financial derivative transactions to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties, and may cause some entities to cease their current business as hedge providers. These changes could reduce the liquidity of the financial derivatives markets thereby reducing the ability of commercial end-users to have access to financial derivatives to hedge or mitigate their exposure to commodity price volatility. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available capital for other commercial operations purposes), materially alter the terms of future swaps relative to the terms of our existing bilaterally negotiated financial derivative contracts, and reduce the availability of derivatives to protect against commercial risks we encounter.

Compliance with environmental and occupational safety and health laws and other government regulations could be costly and could negatively impact our production.

Our operations are subject to numerous and complex laws and regulations relating to environmental and occupational protection. These laws and regulations, which are continuously being reviewed for amendment and/or expansion, may:

- require that we acquire permits before developing our properties;
- restrict the substances that can be released into the environment in connection with drilling, completion and production activities;
- limit or prohibit drilling activities on protected areas such as wetlands or wilderness areas; and
- require remedial measures to mitigate pollution from former operations, including plugging previously abandoned wells.

Under these laws and regulations or under the common law, we could be liable for personal injury and clean-up costs and other environmental, natural resource and property damages, as well as administrative, civil and criminal penalties or injunctions. Failure to comply with these laws and regulations could also result in the occurrence of delays or restrictions in permitting or performance of projects, or the issuance of orders and injunctions limiting or preventing operations relating to our properties in some areas. Under certain environmental laws and regulations, an owner or operator of our properties could be subject to strict, joint and several strict liability for the investigation, removal or remediation of previously released materials or property contamination, regardless of whether the owner or operator was responsible for the release or contamination or whether the operations were in compliance with all applicable laws at the time the release or contamination occurred. Private parties, including the owners of properties upon which wells are drilled or facilities where petroleum hydrocarbons or wastes are taken for reclamation or disposal may also have the right to pursue legal actions to enforce compliance, to seek damages for contamination or for personal injury or property damage. We maintain limited insurance coverage for sudden and accidental environmental damages, but do not maintain insurance coverage for the full potential liability that could be caused by accidental environmental damages. Accordingly, we may be subject to liability in excess of our insurance coverage or may be required to cease production from properties in the event of material environmental damages.

We could also be affected by more stringent laws and regulations adopted in the future, including any related to climate change, engine and other equipment emissions, greenhouse gases and hydraulic fracturing. Changes in environmental laws and regulations occur frequently, and any changes that result in delays or restrictions in permitting or development of projects or more stringent or costly construction, drilling, water management, or completion activities or waste handling, storage, transport, remediation or disposal, emission or discharge requirements could require significant expenditures by Ultra or other operators of the properties to attain and maintain compliance and may otherwise have a material adverse effect on the results of operations, competitive position or financial condition of Ultra or such other operators. Increased scrutiny of the oil and natural gas industry may occur as a result of the EPA's FY 2017-2019 National Enforcement Initiatives, through which the EPA will purportedly address incidences of noncompliance from natural gas extraction and production activities that may cause or contribute to significant harm to public health and/or the environment. In addition, government disruptions, such as an extended federal government shutdown resulting from the failure to pass budget appropriations, adopt continuing funding resolutions or raise the debt ceiling, could delay or halt the granting and renewal of such permits, approvals, and certificates required to conduct our operations.

A significant percentage of our operations are conducted on federal and state lands. These operations are subject to a wide variety of regulations as well as other permits and authorizations which must be obtained from and issued by state and federal agencies. To conduct these operations, we may be required to file applications for permits, seek agency authorizations and comply with various other statutory and regulatory requirements. Complying with any of these requirements may adversely affect our ability to complete our drilling programs at the costs and in the time periods anticipated.

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

More stringent laws and regulations relating to climate change and GHGs may be adopted and could cause us to incur material expenses to comply with such laws and regulations. In the absence of comprehensive federal legislation on GHG emission control, the EPA requires the permitting of GHG emissions for certain sources that require permits due to emissions of other pollutants. The EPA also requires the reporting of GHG emissions from specified large GHG emission sources including onshore and offshore oil and natural gas production facilities and onshore oil and natural gas processing, transmission, storage and distribution facilities, which may include facilities we operate. Reporting of GHG emissions from such facilities is required on an annual basis. We will continue to incur costs associated with this reporting obligation.

In May 2016, the EPA finalized rules to reduce methane emissions and VOC from new, modified or reconstructed sources in the oil and natural gas sector; however, in September 2018, under a new administration, the EPA proposed amendments that would relax requirements of the rules. Similarly, in September 2018, the BLM issued a rule that relaxes or rescinds certain requirements of regulations it previously enacted to reduce methane emissions from venting, flaring, and leaks during oil and gas operations on public lands; California and New Mexico have challenged the new rule in ongoing litigation. In addition, in April 2018, a coalition of states filed a lawsuit in federal district court aiming to force the EPA to establish guidelines for limiting methane emissions from existing sources in the oil and natural gas sector; that lawsuit is pending. Several states are pursuing similar measures to regulate emissions of methane from new and existing sources within the oil and natural gas source category.

In addition, the United States Congress has considered legislation to reduce emissions of GHGs and many states and regions have already taken legal measures to reduce or measure GHG emission levels, often involving the planned development of GHG emission inventories and/or regional cap and trade programs. Most of these cap and trade programs require major sources of emissions or major producers of fuels to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to reduce overall GHG emissions. The cost of these allowances could escalate significantly over time. On an international level, almost 200 nations agreed in December 2015 to 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. Although the present administration has announced its intention to withdraw from the Paris accord, several states and local governments remain committed to its principles in their effectuation of policy and regulations. It is not possible at this time to predict if, how or when the United States or states might impose restrictions on GHGs as a result of the international climate change agreement. The adoption and implementation of any legislation or regulatory programs imposing GHG reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas that we produce. Moreover, incentives to conserve energy or use alternative energy sources as a means of addressing climate change could reduce demand for the oil and natural gas we produce. In addition, parties concerned about the potential effects of climate change have directed their attention at sources of funding for energy companies, which has resulted in certain financial institutions, funds and other sources of capital, restricting or eliminating their investment in oil and natural gas activities.

Potential physical effects of climate change could adversely affect our operations and cause us to incur significant costs in preparing for or responding to those effects.

In an interpretative guidance on climate change disclosures, the SEC indicates that climate change could have an effect on the severity of weather (including hurricanes and floods), sea levels, the arability of farmland, and water availability and quality. If such effects were to occur, our exploration and production operations, including the hydraulic fracturing of our wells, have the potential to be adversely affected. Potential adverse effects could include disruption of our production activities, including, for example, damages to our facilities from powerful winds or floods, or increases in our costs of operation or reductions in the efficiency of our operations, as well as potentially increased costs for insurance coverages in the aftermath of such effects. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process related services provided by midstream companies, service companies or suppliers with whom we have a business relationship. We may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing, including with respect to water use and waste disposal, could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions; however, the EPA has taken certain actions with respect to regulating hydraulic fracturing. For example, the EPA published permitting guidance in February 2014 addressing the use of diesel fuel in fracturing operations; issued CAA final regulations in 2012 and additional CAA regulations in May 2016 governing performance standards for the oil and natural gas industry, for which the EPA in September 2018 has proposed amendments that would relax requirements of the regulations; issued in June 2016 final effluent limitations guidelines under the CWA that waste water from shale natural gas extraction operations must meet before discharging to a publicly-owned treatment plant; and issued in 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, the BLM published a final rule in March 2015 that established new or more stringent standards for performing hydraulic fracturing on federal and Indian lands. However,

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following years of litigation, the BLM rescinded the rule in December 2017; a lawsuit challenging the rule rescission is pending. The BLM also issued rules in November 2016 which seek to limit methane emissions from new and existing oil and gas operations on federal lands, although the present administration is proposing to delay the implementation dates applicable to the requirements under these rules.   The BLM also issued rules in November 2016 to limit methane emissions from new and existing oil and gas operations on federal lands, but subsequently relaxed and rescinded certain requirements of the rules in September 2018; a lawsuit challenging the September 2018 rule revision is pending.

From time to time, the U.S. Congress has considered adopting legislation intended to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. In addition, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. Wyoming has adopted regulations requiring producers to provide detailed information about wells they hydraulically fracture in that state. Some states have adopted or are considering adopting regulations requiring disclosure of chemicals in fluids used in hydraulic fracturing or other restrictions on drilling and completion operations, including requirements regarding casing and cementing of wells; testing of nearby water wells; restrictions on access to, and usage of, water; and restrictions on the type of chemical additives that may be used in hydraulic fracturing operations. Any other new laws or regulations that significantly restrict hydraulic fracturing could make it more difficult or costly for us to perform hydraulic fracturing activities and thereby affect our determination of whether a well is commercially viable. In addition, if hydraulic fracturing is regulated at the federal level, our fracturing activities could become subject to additional permit requirements or operational restrictions and also to associated permitting delays and potential increases in costs. We have conducted hydraulic fracturing operations on most of our existing wells, and we anticipate conducting hydraulic fracturing operations on substantially all of our future wells. As a result, restrictions on hydraulic fracturing could reduce the amount of oil and natural gas that we are ultimately able to produce in commercial quantities and adversely affect our operations and financial condition.

In addition, hydraulic fracturing operations require the use of a significant amount of water. The inability to locate sufficient amounts of water, or dispose of or recycle water used in drilling and production operations, could adversely impact our operations. Moreover, new environmental initiatives and regulations could include restrictions on the ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the development or production of natural gas.

Finally, in some instances, the operation of underground injection wells for the disposal of waste has been alleged to cause earthquakes. In Oklahoma, for example, such issues have led to orders prohibiting continued injection or the suspension of drilling in certain wells identified as possible sources of seismic activity. Such concerns also have resulted in stricter regulatory requirements in some jurisdictions relating to the location and operation of underground injection wells. Although our operations are not located in those jurisdictions, any future orders or regulations addressing concerns about seismic activity from well injection in jurisdictions where we operate could affect our operations.

Changes in tax laws and regulations, including interpretations thereof, or in our operations may impact our effective tax rate and may adversely affect our business, financial condition and operating results.

Tax interpretations, regulations, and legislation in the various jurisdictions in which we and our affiliates operate are subject to measurement uncertainty and the interpretations can impact net income, income tax expense or recovery, and deferred income tax assets or liabilities. In addition, tax rules and regulations, including those relating to foreign jurisdictions, are subject to interpretation and require judgment by us that may be challenged by the taxation authorities upon audit. In past years, legislation has been proposed that would, if enacted into law, make significant changes to U.S. tax laws, including certain key U.S. federal income tax provisions currently available to oil and gas companies. Such legislative changes have included, but not been limited to, (i) the repeal of the percentage depletion allowance for natural gas and oil properties, (ii) the elimination of current deductions for intangible drilling and development costs, and (iii) an extension of the amortization period for certain geological and geophysical expenditures. Although these provisions were largely unchanged in the Tax Act, Congress could consider, and could include, some or all of these proposals as part of future tax reform legislation. Moreover, other more general features of any additional tax reform legislation, including changes to cost recovery rules, may be developed that also would change the taxation of oil and gas companies. It is unclear whether these or similar changes will be enacted in future legislation and, if enacted, how soon any such changes could take effect. Changes in tax laws in any of the multiple jurisdictions in which we operate could result in an unfavorable change in our effective tax rate, which could adversely affect our business, financial condition, and operating results.

The effects of the Tax Act on our business could have an adverse effect on our net income.

On December 22, 2017, the Tax Act was enacted and made significant changes to the Code. Such changes include a reduction in the corporate tax rates and limitation on certain deductions and credits, among other changes. In addition, adverse changes in the underlying profitability and financial outlook of our operations and changes in tax law could lead to changes in our valuation allowance against deferred tax assets on our balance sheets, which could materially affect our results of operations. While we believe that the Tax Act will not impact the ability of our deferred tax assets, as re-measured, including our significant U.S. federal net operating loss carryover, to reduce the amount or cash income taxes payable in the future, we continue to monitor clarifications and new regulations related to the Tax Act that could impact the Company.

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Cyber-attacks targeting systems and infrastructure used by the oil and gas industry may adversely impact our operations.

Our business has become increasingly dependent on digital technologies, including technologies operated by or under the control of third parties, to conduct certain exploration, development, production and financial activities. We depend on digital technology to estimate quantities of oil and gas reserves, process and record financial and operating data, analyze seismic and drilling information, and communicate with our employees and third-party partners. Unauthorized access to (or the loss of Company access to) our seismic data, reserves information or other proprietary information could lead to data corruption, communication interruption, or other operational disruptions in our exploration or production operations. Also, computers control nearly all of the oil and gas distribution systems in the United States and abroad, which are necessary to transport our production to market. A cyber-attack directed at oil and gas distribution systems could damage critical distribution and storage assets or the environment, delay or prevent delivery of production to markets and make it difficult or impossible to accurately account for production and settle transactions.

While our operations and financial condition have not been materially and adversely affected by cyber-attacks, there is no assurance that we will not suffer such attacks and resulting losses in the future. Further, as cyber-attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber-attacks.

Our business and the trading prices of our securities could be negatively impacted by the actions of so-called “activist” stockholders.

If we become the subject of activity by activist shareholders, this could disrupt our business, distract our management and Board of Directors, and negatively impact our business and the trading prices of our securities, including our common stock. Responding to shareholder activism can be costly and time-consuming, disrupt our operations, and divert the attention of management and our employees from our strategic initiatives. Furthermore, activist campaigns can create perceived uncertainties as to our future direction, strategy, or leadership and may result in the loss of potential business opportunities, harm our ability to attract new employees, investors, customers, and joint venture partners, and cause our stock price to experience periods of volatility.

If a sustained financial or economic downturn occurs domestically or internationally, capital market conditions and commodity prices may deteriorate, which could materially and adversely affect our liquidity, results of operations and ability to execute our business.

Global and domestic economic conditions are difficult for us to forecast and impossible for us to control. Similarly, conditions in global and domestic capital markets, including debt and equity markets, are difficult for us to forecast and impossible for us to control. Adverse changes, even material adverse changes, in global and domestic economic conditions and in domestic and international capital markets may occur without warning. Although there are steps we can take to anticipate and mitigate such changes, we may fail to do so. If we fail to successfully anticipate or mitigate such matters, adverse changes in global or domestic economic conditions or capital markets, especially materially adverse changes, could increase our costs, limit our financial flexibility, and materially and adversely affect our business, results of operations, and liquidity.

Unless we are able to replace reserves that we have produced, our cash flows and production will decrease over time.

Our future success depends on our ability to find, acquire, develop and produce additional oil and gas reserves that are economically recoverable. Without successful exploration, development or acquisition activities, our reserves and production will decline. We can give no assurance that we will be able to find, develop or acquire additional reserves at acceptable costs.

We may not be able to replace our reserves or generate cash flows if we are unable to raise capital. We will be required to make substantial capital expenditures to develop our existing reserves and to discover new oil and gas reserves.

Our ability to continue exploration and development of our properties and to replace reserves depends upon our ability to comply with our debt covenants, renegotiate our debt agreements, raise significant additional financing, or to seek and obtain other arrangements with industry participants in lieu of raising additional financing. Any arrangements that may be entered into could be expensive to us if such arrangements can be made at all. There can be no assurance that we will be able to raise additional capital in light of factors such as our financial condition, the market demand for our securities, the general condition of financial markets for independent oil and gas companies (including the markets for debt), oil and natural gas prices and general market conditions. See Part II, Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources" for a discussion of our capital budget. Continued periods of depressed commodity prices or further commodity price decreases could have a material adverse effect on our ability to fund capital expenditures. Without the ability to fund capital expenditures, we would be unable to replace reserves and production. There can also be no assurance that we will be able to obtain other satisfactory arrangements to allow further exploration and development of our properties if we are unable to raise additional capital.

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We expect to use our cash from operations, cash from draws on the Revolving Credit Facility and cash on hand to fund our capital budget, our operating costs and our interest service obligations during 2019. The loan commitment and the aggregate amount of money that we can borrow under the Revolving Credit Facility and from other sources is revised from time to time based on certain restrictive covenants. A change in our ability to meet the restrictive covenants may limit our ability to borrow. If this occurred, we may have to sell assets or seek substitute financing. We can make no assurances that we would be successful in selling assets or arranging substitute financing. See Part II, Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources" for information about our liquidity, available cash on hand, and the description of the current debt agreements.

Our operations may be interrupted by severe weather or drilling restrictions.

Our operations are conducted exclusively in the Rocky Mountain region of the United States. The weather in this area can be extreme and can cause interruption in our exploration and production operations. Severe weather can result in damage to our facilities entailing longer operational interruptions and significant capital investment. Likewise, our operations are subject to disruption from winter storms and severe cold, which can limit operations involving fluids and impair access to our facilities.

We are exposed to operating hazards and uninsured risks that could adversely impact our results of operations and cash flow.

The oil and natural gas business involves a variety of operating risks, including blowouts, fire, explosion, pipe failure, casing collapse, abnormally pressured formations, and environmental hazards such as oil spills, natural gas leaks, discharges of toxic gases, underground migration and surface spills or mishandling of fracture fluids, including chemical additives. The occurrence of any of these events with respect to any property we own or operate (in whole or in part) could have a material adverse impact on us. We and the operators of our properties maintain insurance in accordance with customary industry practices and in amounts that management believes to be reasonable. However, insurance coverage is not always economically feasible and is not obtained to cover all types of operational risks. The occurrence of a significant event that is not fully insured could have a material adverse effect on our financial condition.

There are risks associated with our drilling activity that could impact our results of operations.

Our oil and natural gas operations are subject to all of the risks and hazards typically associated with drilling, completion, production and transportation of, oil and natural gas. These risks include the necessity of spending large amounts of money for identification and acquisition of properties and for drilling and completion of wells. In the drilling and completing of wells, failures and losses may occur before any deposits of oil or natural gas are found and produced. The presence of unanticipated pressure or irregularities in formations, blow-outs or accidents may cause such activity to be unsuccessful, resulting in a loss of our investment in such activity and possible liabilities. If oil or natural gas is encountered, there can be no assurance that it can be produced in quantities sufficient to justify the cost of continuing such operations or that it can be marketed satisfactorily.

Our decision to drill a prospect is subject to a number of factors which may alter our drilling schedule or our plans to drill at all.

A prospect is an area in which our geoscientists have identified what they believe, based on available seismic and geological information, to be indications of hydrocarbons. Our prospects are in various stages of review. Whether or not we ultimately drill our prospects depends on many factors, including but not limited to: the availability and cost of capital; receipt of additional seismic data or reprocessing of existing data; material changes in current of future expected oil or natural gas prices; the costs and availability of drilling and completion equipment; the success or failure of wells drilled in similar formations or which would use the same production facilities and equipment; changes in the estimates of costs to drill or complete wells; decisions of our joint working interest owners; and regulatory, permitting and other governmental requirements. It is possible these factors and others may cause us to alter our drilling schedule or determine that a prospect should not be pursued at all.

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

We own interests in properties that are operated by third parties. The success, timing and costs of drilling, completion, and other development activities on our non-operated properties depend on a number of factors that are beyond our control. Because we have only a limited ability to influence and control the operations of our non-operated properties, we can give no assurances that we will realize our targeted returns with respect to those properties.

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Our business depends on gathering and transportation facilities owned by others. Any limitation in the availability of those facilities would interfere with our ability to market the oil and natural gas that we produce.

The marketability of our oil and natural gas production will depend in part on the availability, proximity and capacity of gathering and pipeline systems owned by third parties. The amount of oil and natural gas that can be produced and sold is subject to curtailment in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage to the gathering or transportation system, or lack of contracted capacity on such systems. The curtailments arising from these and similar circumstances may last from a few days to several months. In many cases, we are provided only with limited, if any, notice as to when these circumstances will arise and their duration. Any significant curtailment in gathering system or pipeline capacity, or significant delay in the construction of necessary gathering and transportation facilities, could adversely affect our business, results of operations, financial condition and prospects.

We may fail to fully identify problems with any properties we acquire.

We acquired a portion of our acreage position through property acquisitions and acreage trades, and we may acquire additional acreage in these or other regions in the future. Although we conduct a review of properties we acquire which we believe is consistent with industry practices, we can give no assurance that we have identified or will identify all existing or potential problems associated with such properties or that we will be able to mitigate any problems we do identify.

Our acquisitions may perform worse than we expected or prove to be worth less than what we paid because of uncertain factors and matters beyond our control. In addition, our acquisitions could expose us to potentially significant liabilities.

When we make acquisitions of oil and gas properties, we make assumptions about many uncertain factors, including estimates of recoverable reserves, expected timing of recovering acquired reserves, future commodity prices, expected development and operating costs, and other matters, many of which are beyond our control. Assumptions about uncertain factors may be wrong, and the properties we acquire may perform worse than we expect, materially and adversely affecting our operations and financial condition.

Improvements in or new discoveries of alternative energy technologies could have a material adverse effect on our financial condition and results of operations.

Since our business depends on the level of activity in the oil and natural gas industry, any improvement in or new discoveries of alternative energy technologies that increase the use of alternative forms of energy and reduce the demand for oil and natural gas could have a material adverse effect on our business, financial condition, and operations.

Any future implementation of price controls on oil and natural gas would affect our operations.

The United States Congress may in the future impose some form of price controls on either oil, natural gas, or both. Any future limits on the price of oil or natural gas could negatively affect the demand for our services and consequently, have a material adverse effect on our business, financial condition, and results of operations.

Damage to our reputation could damage our business.

Our reputation is a critical factor in our relationships with employees, investors, customers, suppliers and joint venture partners. If we fail to address, or appear to fail to address, issues that give rise to reputational risk, including those described throughout this “Risk Factors” section, we could significantly harm our reputation. Our reputation may also be damaged by how we respond to corporate crises. Corporate crises can arise from catastrophic events as well as from incidents involving unethical behavior or misconduct; allegations of legal noncompliance; internal control failures; corporate governance issues; data breaches; workplace safety incidents; environmental incidents; media statements; the conduct of our suppliers or representatives; and other issues or incidents that, whether actual or perceived, result in adverse publicity. If we fail to respond quickly and effectively to address such crises, the ensuing negative public reaction could significantly harm our reputation and could lead to increases in litigation claims and asserted damages or subject us to regulatory actions or restrictions.

Damage to our reputation could negatively affect the demand for our services and consequently, have a material adverse effect on our business, financial condition, and results of operations. It could also reduce investor confidence in us, adversely affecting our stock price. Moreover, repairing our reputation may be difficult, time-consuming and expensive.

Forward-Looking Statements

This report contains or incorporates by reference forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the “Securities Act”), Section 21E of the Exchange Act, and the Private Securities Litigation Reform Act of 1995. Except for statements of historical facts, all statements included in this document, including those statements preceded by, followed by or that otherwise include the words “believe,” “expects,” “anticipates,” “intends,” “estimates,” “projects,” “target,” “goal,” “plans,” “objective,” “should,” or similar expressions or vari such expressions are forward-looking statements. The Company can give no assurances that the assumptions upon which such forward-looking statements are based will prove to be correct.

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Forward-looking statements include statements regarding:

- our oil and natural gas reserve quantities, and the discounted present value of those reserves;
- the amount and nature of our capital expenditures;
  - drilling of vertical and horizontal wells;
- the timing and amount of future production and operating costs;
- our ability to respond to low natural gas prices;
- our levels of indebtedness
- business strategies and plans of management; and
- prospect development and property acquisitions.

Some of the risks which could affect our future results and could cause results to differ materially from those expressed in our forward-looking statements include:

- volatility and, especially, declines or substantial declines and weakness in natural gas or oil prices;
- our ability to maintain adequate liquidity in view of current natural gas prices;
- our ability to comply with the covenants and restrictions of the agreements governing our indebtedness, or our ability to amend or replace the agreements governing our indebtedness;
- any future global economic downturn;
- general economic conditions, including the availability of credit and access to existing lines of credit;
- conditions in capital markets, including the availability of capital to companies in the oil and gas business;
- the volatility of oil and natural gas prices;
- the uncertainty of estimates of oil and natural gas reserves;
- the impact of competition;
- the availability and cost of seismic, drilling and other equipment;
- our decisions about how we allocate capital and resources among strategic opportunities;
- operating hazards inherent in the exploration for and production of oil and natural gas;
- difficulties encountered during the exploration for and production of oil and natural gas;
- difficulties encountered in delivering oil and natural gas to commercial markets;
- changes in customer demand and producers' supply;
- the uncertainty of our ability to attract capital and obtain financing on favorable terms;
- reductions in our borrowing base under our Revolving Credit Facility;
- compliance with, or the effect of changes in, the extensive governmental regulations regarding the oil and natural gas business, including those related to climate change and greenhouse gases, disposal of produced water, drilling fluids and other wastes, hydraulic fracturing and access to and the use of water, and financial derivatives and hedging activities;
- actions of operators of our oil and natural gas properties; and
- weather conditions.

The information contained in this report, including the information set forth under the heading "Risk Factors," identifies additional factors that could affect our operating results and performance. We urge you to carefully consider these factors and the other cautionary statements in this report. Our forward-looking statements speak only as of the date made, and we have no obligation to update these forward-looking statements.

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Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

Location and Characteristics

The Company owns oil and natural gas leases in Wyoming. The leases in Wyoming are primarily federal leases with 10-year lease terms until establishment of production. Production extends the lease terms until cessation of that production. The Company previously owned oil and natural gas leases in Utah and Pennsylvania, which the Company sold in September 2018 and December 2017, respectively.

Green River Basin, Wyoming

Acreage. As of December 31, 2018, the Company owned oil and natural gas leases totaling approximately 114,000 gross (79,000 net) acres in southwest Wyoming's Green River Basin. Most of this acreage covers the Pinedale and Jonah fields. Of the total acreage position in Wyoming and as of December 31, 2018, approximately 41,000 gross (27,000 net) acres were developed, and 73,000 gross (52,000 net) acres were undeveloped. The developed and undeveloped portion represents 100% of the Company's total developed and undeveloped net acreage. The Company operates 89% of its acreage position in the Pinedale field and 89% of its production.

Lease maintenance costs in Wyoming were approximately $1.0 million for the year ended December 31, 2018. The Company currently owns 68 leases totaling 80,000 gross (54,000 net) acres that are held by production and activities ("HBP"). The HBP acreage includes all of the Company's leases within the productive area of the Pinedale and Jonah fields.

Development Wells. Development wells are wells that were drilled in the current year that were proved undeveloped locations in the prior year's reserve report. During 2018, the Company participated in the drilling of 107.0 gross (80.7 net) productive development wells on the Green River Basin properties, of which 102.0 gross (77.1 net) productive development wells were vertical and 5.0 gross (3.6 net) productive development wells were horizontal. At December 31, 2018, there were 9.0 gross (6.6 net) additional development wells that commenced during the year and were either still drilling or had operations suspended at a depth short of total depth.

Exploratory Wells. Exploratory wells are wells that were drilled in the current year that were not proved undeveloped locations in the prior year's reserve report. During 2018, the Company participated in the drilling of a total of 28.0 gross (19.8 net) productive exploratory wells on the Green River Basin properties, of which 14.0 gross (9.0 net) productive exploratory wells were vertical and 14.0 gross (10.8 net) productive exploratory wells were horizontal. At December 31, 2018, there were 11.0 gross (5.1 net) additional exploratory wells that commenced during the year that were either still drilling or had operations suspended at a depth short of total depth and thus a determination of productive capability could not be made at year-end.

Seismic Activity. The Company owns 492 square miles of 3D seismic data in Wyoming which, when overlap is subtracted, covers 415 square miles. The data consists of both proprietary data and data licensed from independent seismic contractors and provides coverage over the entire productive areas of Pinedale and Jonah fields. During 2016, the Company completed a project to merge the various data sets and reprocess the entire volume.

Divested Assets

Uinta Basin, Utah. During the third quarter 2018, the Company sold the oil and gas properties covering approximately 8,300 gross (7,800 net) acres in the Uinta Basin in Utah for net cash proceeds of $69.3 million, including management fees of $0.6 million. This acreage is located in Uintah County in the eastern portion of the Uinta Basin.

Lease maintenance costs in Utah for the year ended December 31, 2018 were not significant.

The Company did not participate in the drilling of any development or exploratory wells on the Utah properties during 2018.

Pennsylvania. During the fourth quarter of 2017, the Company sold the oil and gas leases covering 144,000 gross (72,000 net) acres in the Pennsylvania portion of the Appalachian Basin for a cash purchase price of approximately $115.0 million.

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Oil and Gas Reserves

The following table sets forth the Company's quantities of proved reserves for the years ended December 31, 2018, 2017 and 2016. The table summarizes the Company's proved reserves, the estimated future net revenues from these reserves and the standardized measure of discounted future net cash flows attributable thereto at December 31, 2018, 2017 and 2016. In 2017, the Company renegotiated its existing gas processing contracts in Wyoming. These gas processing contracts are keep-whole contracts in which the Company shares in the economic benefit of processing and accordingly does not include the NGL volumes in its reserves. Prior to this time, the Company's contracts provided for the election to process NGLs. As of December 31, 2018 and 2017, proved undeveloped reserves represented 23% of the Company's total proved reserves. The Company did not record any proved undeveloped reserves for the year ended December 31, 2016 because of the going concern assessment at period end.

	December 31,		
	2018	2017	2016
	($ amounts in thousands, except per unit data)		
Proved Developed Reserves			
Natural gas (MMcf)	2,243,956	2,261,289	2,321,613
Oil (MBbl)	17,876	21,652	21,475
Natural gas liquids (MBbl)	—	71	9,903
Proved Undeveloped Reserves			
Natural gas (MMcf)	677,877	694,703	—
Oil (MBbl)	5,569	5,466	—
Natural gas liquids (MBbl)	—	—	—
Total Proved Reserves (MMcfe) (1)	3,062,503	3,119,126	2,509,881
Estimated future net cash flows, before income tax	$4,724,843	$4,377,344	$2,791,229
Standardized measure of discounted future net cash flows, before income taxes (2)	$2,585,540	$2,384,328	$1,690,946
Future income tax	$(180,057)	$—	$—
Standardized measure of discounted future net cash flows, after income tax	$2,405,483	$2,384,328	$1,690,946
Calculated average price (3)			
Gas ($/Mcf)	$2.59	$2.59	$2.07
Oil ($/Bbl)	$63.49	$48.05	$37.90
NGLs ($/Bbl)	$—	$26.85	$19.17

(1) Oil, condensate and NGLs are converted to natural gas at the ratio of one barrel of liquids to six Mcf of natural gas. This conversion ratio, which is typically used in the oil and gas industry, represents the approximate energy equivalent of a barrel of oil or condensate to an Mcf of natural gas.

(2) Management believes that the presentation of the standardized measure of discounted future net cash flows, before income taxes, of estimated proved reserves, discounted at 10% per annum, may be considered a non-Generally Accepted Accounting Principle financial measure as defined in Item 10(e) of Regulation S-K, therefore the Company has included this reconciliation of the measure to the most directly comparable Generally Accepted Accounting Principle ("GAAP") financial measure (standardized measure of discounted future net cash flows, after income taxes). Management believes that the presentation of the standardized measure of future net cash flows

before income taxes provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and gas companies. Because many factors that are unique to each individual company may impact the amount of future income taxes to be paid, the use of the pre-tax measure provides greater comparability when evaluating companies. It is relevant and useful to investors for evaluating the relative monetary significance of the Company's oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of the Company's reserves to other companies. The standardized measure of discounted future net cash flows, before income taxes, is not a measure of financial or operating performance under GAAP, nor is it intended to represent the current market value of the estimated oil and natural gas reserves owned by the Company. Standardized measure of discounted future net cash flows, before income taxes, should not be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows as defined under GAAP.

(3) As prescribed by SEC rules, our reserve estimates at December 31, 2018, 2017 and 2016, reflect prices based on the average of the monthly prices during the 12-month period before the ending date of the period covered by this report determined as an un-weighted, arithmetic average of the first-day-of-the-month price for each month within such period.

Since January 1, 2016, no crude oil, natural gas or NGL reserve information has been filed with, or included in any report to, any federal authority or agency other than the SEC and the Energy Information Administration ("EIA") of the U.S. Department of Energy. We file Form 23, including reserve and other information, with the EIA.

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Proved Undeveloped Reserves

Changes in proved undeveloped reserves: Changes to the Company's proved undeveloped reserves ("PUDs") during 2018 are summarized in the table below. These changes include updates to prior PUDs, the addition of new PUDs associated with the current development plans, the transfer of PUDs to unproved categories due to development plan changes, and the impact of changes in economic conditions, including changes in commodity prices. The Company's year-end development plans and associated PUDs are consistent with SEC guidelines for PUD development within five years. The Company annually reviews all PUDs to ensure an appropriate plan for development exists. As of December 31, 2018, 100% of the proved undeveloped locations are located in Wyoming.

	MMcfe
Proved undeveloped reserves, December 31, 2017	727,499
Converted to proved developed	(322,024)
Proved undeveloped reserve extensions	40,472
Proved undeveloped reserves purchased	—
Proved undeveloped reserve revisions	265,346
Proved undeveloped reserves, December 31, 2018	711,293

Conversions: In 2018, the conversion rate was 44.3% based on PUDs recorded as of December 31, 2018.

Additions/Extensions: In 2018, the Company's reserve additions were comprised of Pinedale drilling locations that moved into the five-year proved undeveloped window. These locations have never been previously classified as proved undeveloped.

Purchases: In 2018, there were no purchases related to PUD reserves.

Revisions: In 2018, price and performance revisions, along with the transfers of previously booked PUD locations, are included in the reported revisions.

Internal Controls Over Reserve Estimating Process

Our policies and practices regarding internal controls over the recording of reserves are structured to objectively and accurately estimate our oil and gas reserve quantities and present values in compliance with the SEC's regulations and GAAP. Our Director of Reservoir and Development is primarily responsible for overseeing the preparation of the Company's reserve estimates and has a Bachelor of Science degree in Petroleum Engineering with over 14 years of experience.

The Company's internal controls over reserve estimates include reconciliation and review controls, including an independent internal review of assumptions used in the estimation as well as ultimate approval of our capital budget and review of our development plan by our senior management and Board of Directors. The development plan underlying the Company's PUD reserves, if any, is further subject to internal controls, including a comparison of future development costs to historical expenditures as well as our future development plan and financial capabilities, and an evaluation of the estimated profitability of each location at the time the report is prepared. The development plan underlying the Company's proved undeveloped reserves, adopted every year by senior management, is based on the best information available at the time of adoption. As factors such as commodity price, service costs, performance data, and asset mix are subject to change, the Company occasionally revises its development plan. Development plan revisions include deferrals, removals, and substitutions of previously scheduled PUD reserve locations. These occasional changes achieve the purpose of maximizing profitability and are in the best interest of the Company's shareholders.

The estimates of proved reserves and future net revenue as of December 31, 2018 are based upon the use of technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information and property ownership interests. The reserves were estimated using deterministic methods; these estimates were prepared in accordance with generally accepted petroleum engineering and evaluation principles. Standard engineering and geoscience methods, such as reservoir modeling, performance analysis, volumetric analysis and analogy, that were considered to be appropriate and necessary to establish reserve quantities and reserve categorization that conform to SEC definitions and rules and regulations, were also used. As in all aspects of oil and natural gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, these estimates necessarily represent only informed professional judgment.

The Company engaged Netherland, Sewell & Associates, Inc. ("NSAI"), a third-party, independent engineering firm, to prepare the reserve estimates for all of the Company's assets for the years ended December 31, 2018, 2017 and 2016 in this annual report.

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Our internal professional staff works closely with NSAI to ensure the integrity, accuracy and timeliness of data that is furnished to them for their reserve estimation process. In addition, other pertinent data is provided such as seismic information, geologic maps, well logs, production tests, well performance data, operating procedures and relevant economic criteria. We make available all information requested, including our pertinent personnel, to the external engineers as part of their evaluation of our reserves. The report of NSAI is included as Exhibit 99.1 to this annual report.

The reserves estimates shown herein have been independently evaluated by NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F 2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are Mr. Sean A. Martin and Mr. Philip R. Hodgson. Mr. Martin, a Licensed Professional Engineer in the State of Texas (No. 125354), has been practicing consulting petroleum engineering at NSAI since 2014 and has over seven years of prior industry experience. He graduated from University of Florida in 2007 with a Bachelor of Science Degree in Chemical Engineering. Mr. Hodgson, a Licensed Professional Geoscientist in the State of Texas (No. 1314), has been practicing consulting petroleum geoscience at NSAI since 1998 and has over 14 years of prior industry experience. He graduated from University of Illinois in 1982 with a Bachelor of Science Degree in Geology and from Purdue University in 1984 with a Master of Science Degree in Geophysics. Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

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Production Volumes, Average Sales Prices and Average Production Costs

The following table sets forth certain information regarding the production volumes and average sales prices received for and average production costs associated with the Company's sale of oil and natural gas for the periods indicated.

	Year ended December 31,		
	2018	2017	2016
	(In thousands, except per unit data)		
Production			
Natural gas (Mcf)	260,406	260,009	264,278
Oil (Bbl)	2,442	2,775	2,912
Total (Mcfe)	275,058	276,659	281,748
Revenues			
Natural gas sales	$722,313	$748,682	$609,756
Oil sales	153,534	133,368	111,335
Other revenues	16,652	9,823	—
Total revenues	$892,499	$891,873	$721,091
Lease Operating Expenses			
Lease operating expenses (1)	$90,290	$92,326	$89,134
Facility lease expense	25,947	21,749	20,686
Severance/production taxes	93,322	91,067	69,737
Gathering	89,806	86,953	86,809
Total lease operating expenses	$299,365	$292,095	$266,366
Average Realized Prices			
Natural gas ($/Mcf, including realized gains (losses) on commodity derivatives)	$2.48	$2.92	$2.31
Natural gas ($/Mcf, excluding realized gains (losses) on commodity derivatives)	$2.77	$2.88	$2.31
Oil ($/Bbl), including realized gains (losses) on commodity derivatives)	$59.44	$48.05	$38.24
Oil ($/Bbl), excluding realized gains (losses) on commodity derivatives)	$62.88	$48.05	$38.24
Average Costs per Mcfe			
Lease operating expenses	$0.33	$0.33	$0.32
Facility lease expense	$0.09	$0.08	$0.07
Severance/production taxes	$0.34	$0.33	$0.25
Gathering	$0.33	$0.31	$0.31
Transportation charges	$—	$—	$0.07
DD&A	$0.74	$0.59	$0.44
General & administrative	$0.09	$0.14	$0.03
Interest	$0.54	$1.31	$0.24
Total costs per Mcfe	$2.46	$3.09	$1.73

(1) Lease operating costs include lifting costs and remedial workover expenses.

The following table sets forth the net sales volumes, operating expenses and average realized natural gas prices attributable to the Pinedale field, which is the only field that contained 15% or more of our total estimated proved reserves as of December 31, 2018:

	Year ended December 31,		
	2018	2017	2016
	(In thousands)		
Pinedale Field:			
Production (Mcfe)	264,786	256,695	256,881
Operating expenses	$282,376	$265,051	$241,975
Average realized price ($/Mcf excluding realized gains (losses) on commodity derivatives)	$2.78	$2.90	$2.35
Average realized price ($/Mcf including realized gains (losses) on commodity derivatives)	$2.48	$2.95	$2.35

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Delivery Commitments

With respect to the Company’s natural gas production, from time to time the Company enters into transactions to deliver specified quantities of gas to its customers. None of these commitments require the Company to deliver gas or oil produced specifically from any of the Company’s properties, and all of these commitments are priced on a floating basis with reference to an index price. In addition, none of the Company’s reserves are subject to any priorities or curtailments that may affect quantities delivered to its customers, any priority allocations or price limitations imposed by federal or state regulatory agencies or any other factors beyond the Company’s control that may affect its ability to meet its contractual obligations other than those discussed in Part I. Item 1A. “Risk Factors.” If for some reason our production is not sufficient to satisfy these commitments, subject to the availability of capital, we could purchase volumes in the market or make other arrangements to satisfy the commitments.

Productive Wells

As of December 31, 2018, the Company’s total gross and net wells were as follows:

	Gross Wells	Net Wells
Productive Wells*		
Operated	2,204	1,882
Operated by others	836	234
Total productive wells	3,040	2,116

* Productive wells are producing wells, shut-in wells the Company deems capable of production, wells that are waiting for completion, plus wells that are drilled/cased and completed, but waiting for pipeline hook-up. A gross well is a well in which a working interest is owned. The number of net wells represents the sum of fractional working interests the company owns in gross wells.

Oil and Gas Acreage

The primary terms of the Company’s oil and gas leases expire at various dates. Much of the Company’s undeveloped acreage is held by production, which means that the Company will maintain its rights in these leases as long as oil or natural gas is produced from the acreage by it or by other parties holding interests in producing wells on those leases. In some cases, if production from a lease ceases, the lease will expire, and in some cases, if production from a lease ceases, the Company may maintain the lease by additional operations on the acreage.

The Company does not believe the risk of remaining terms of its leases are material. The Company expects to maintain essentially all the material leases among its oil and gas properties by production, operations, extensions or renewals. The Company does not expect to lose material lease acreage because of failure to drill due to inadequate capital, equipment or personnel. The Company has, based on its evaluation of prospective economics, allowed acreage to expire and it may allow additional acreage to expire in the future. As of December 31, 2018, the Company does not anticipate any Wyoming leased acres to expire in 2019 and estimates that approximately 8,200 net leased acres in Wyoming may expire in 2020 and beyond.

As of December 31, 2018, the Company had total gross and net developed and undeveloped oil and natural gas leasehold acres in the United States as set forth below.

	Developed Acres		Undeveloped Acres	
	Gross	Net	Gross	Net
Wyoming	41,000	27,000	73,000	52,000

Drilling Activities

For each of the three fiscal years ended December 31, 2018, 2017 and 2016, the number of gross and net wells drilled by the Company was as follows:

Wyoming — Green River Basin

	2018		2017		2016	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	107.0	80.7	—	—	—	—
Dry	—	—	—	—	—	—
Total	107.0	80.7	—	—	—	—

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At December 31, 2018, there were 9.0 gross (6.6 net) additional development wells that were either drilling or had operations suspended. This includes wells in the Pinedale field.

	2018		2017		2016	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells						
Productive	28.0	19.8	210.0	172.1	94.0	68.6
Dry	—	—	—	—	—	—
Total	28.0	19.8	210.0	172.1	94.0	68.6

At December 31, 2018, there were 11.0 gross (5.1 net) additional exploratory wells that were either drilling or had operations suspended in the Pinedale field.

Utah

The Company divested its Utah assets during the third quarter of 2018. For the years ended December 31, 2018, 2017 and 2016, the Company did not drill any development or exploratory wells on its Utah acreage.

Pennsylvania

The Company divested its Pennsylvania assets during the fourth quarter of 2017. For the years ended December 31, 2017 and 2016, the Company did not drill any development or exploratory wells on its Pennsylvania acreage.

Colorado

The Company did not conduct any operations on this acreage during 2018, 2017 or 2016. In 2014, the Company sold the surface rights to its Colorado undeveloped acreage and retained some oil and gas (mineral) rights. The Company no longer owns any leased acreage in Colorado and has no immediate plans for further exploration in Colorado during 2019.

Item 3. Legal Proceedings.

See Note 12 for discussion of on-going claims and disputes that arose during our chapter 11 proceedings, certain of which may be material. The Company is also currently involved in various routine disputes and allegations incidental to its business operations. While it is not possible to determine or predict the ultimate disposition of these matters, the Company believes that the resolution of all such pending or threatened litigation is not likely to have a material adverse effect on the Company’s financial position, or results of operations.

Item 4. Mine Safety Disclosures.

None.

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PART II

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

The Company’s common shares are traded on the NASDAQ (the “NASDAQ”) under the symbol “UPL”.

As of February 28, 2019, there were approximately 329 holders of record of the common shares.

Dividends

The Company has not declared or paid and does not anticipate declaring or paying any dividends on its common shares in the near future. Additionally, our Credit Agreement (defined below), Term Loan Agreement (defined below), and the indentures governing the Second Lien Notes (defined below) place certain restrictions on our ability to pay cash dividends. The Company intends to retain its cash flow from operations for the future operation and development of its oil and gas properties.

Performance Graph

The following share price performance graph is intended to allow review of shareholder returns, expressed in terms of the appreciation of the Company’s common shares relative to two broad-based stock performance indices. The information is included for historical comparative purposes only and should not be considered indicative of future share performance. The graph below matches the Company’s cumulative total shareholder return on common stock since the date of the Company’s emergence from chapter 11 proceedings with the cumulative total returns of the NYSE Composite index and the Dow Jones US Exploration and Production TSM index. The graph tracks quarterly performance of a $100 investment in our common stock and each respective index (with the reinvestment of all dividends) from the April 13, 2017 through December 31, 2018.

Unregistered Sales of Equity Securities

On December 21, 2018, the Company completed the Exchange Transaction, pursuant to which the exchanging noteholders exchanged (i) $505 million aggregate principal amount, or 72.1%, of the issued and outstanding 2022 Notes and (ii) $275 million aggregate principal amount, or 55.0%, of the issued and outstanding 2025 Notes for (a) $545.0 million aggregate principal amount of Second Lien Notes of Ultra Resources and (b) an aggregate of 10,919,499 Warrants of the Company. See to Item 7. “Management’s Discussion and Analysis”, for additional details regarding the Exchange Transaction.

Each Warrant is initially exercisable for one common share of the Company at an initial exercise price of $0.01 per Warrant (the “Exercise Price”). No Warrants will be exercisable until the date on which the volume-weighted average price of the Company’s common shares is at least $2.50 per common share for 30 consecutive trading days (the “Trading Price Condition”). Subject to the Trading Price Condition, the Warrants are exercisable at the option of the holders thereof from December 21, 2018 until July 14, 2025, at which time all unexercised Warrants will expire and the rights of the holders of such Warrants to purchase common shares will terminate.

The Warrants issued in the Exchange Transaction were offered and sold pursuant to the exemption provided by Section 4(a)(2) of the Securities Act. This offer was made by the Company to a limited number of persons, each of which is an accredited investor (within the meaning of Rule 501 promulgated under the Securities Act).

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Item 6. Selected Financial Data.

The selected consolidated financial information presented below for the years ended December 31, 2018, 2017, 2016, 2015 and 2014 is derived from the Consolidated Financial Statements of the Company.

	Year Ended December 31, 2018	2017	2016	2015	2014
	(In thousands, except per share data)				
Statement of Operations Data:					
Revenues:					
Natural gas sales	$722,313	$748,682	$609,756	$696,730	$969,850
Oil sales	153,534	133,368	111,335	142,381	260,170
Other revenues	16,652	9,823	—	—	—
Total operating revenues	892,499	891,873	721,091	839,111	1,230,020
Expenses:					
Production expenses and taxes	299,365	292,095	266,366	288,231	280,631
Transportation charges	—	—	20,049	83,803	77,780
Depletion, depreciation and amortization	204,255	161,945	125,121	401,200	292,951
Ceiling test and other impairments	—	—	—	3,144,899	—
General and administrative	25,005	39,548	9,179	7,387	19,069
Other expenses	9,118	—	—	—	—
Total operating expenses	537,743	493,588	420,715	3,925,520	670,431
Other:					
Interest expense	(148,316)	(361,367)	(66,565)	(171,918)	(126,157)
Gain (loss) on commodity derivatives	(145,212)	28,412	—	42,611	82,402
Deferred gain on sale of liquids gathering system	10,553	10,553	10,553	10,553	10,553
Contract settlement income (expense), net	12,656	(52,707)	(131,106)	—	—
Gain on sale of property	—	—	—	—	8,022
Litigation expense	—	—	—	(4,401)	—
Restructuring expenses	—	—	(7,176)	—	—
Reorganization items, net	—	140,907	(47,503)	—	—
Other (expense) income, net	1,212	(237)	(3,082)	(2,060)	2,618
Total other income (expense), net	(269,107)	(234,439)	(244,879)	(125,215)	(22,562)
Income (loss) before income taxes	85,649	163,846	55,497	(3,211,624)	537,027
Income tax (benefit)	442	(13,294)	(654)	(4,404)	(5,824)
Net income (loss)	$85,207	$177,140	$56,151	$(3,207,220)	$542,851
Basic Earnings (Loss) per Share:					
Net income (loss) per common share — basic (1)	$0.43	$1.08	$0.70	$(40.14)	$6.79

Fully Diluted Earnings (Loss) per Share:					
Net income (loss) per common share — fully diluted (1)	$0.43	$1.08	$0.70	$(40.14)	$6.73
Statement of Cash Flows Data (2):					
Net cash provided by (used in):					
Operating activities	$310,897	$65,268	$311,070	$515,536	$712,582
Investing activities	$(401,710)	$(435,311)	$(278,900)	$(512,757)	$(1,600,743)
Financing activities	$91,849	$(16,737)	$368,621	$(7,557)	$886,414
Balance Sheet Data:					
Cash and cash equivalents	$17,014	$16,631	$401,478	$4,143	$8,919
Working capital (deficit)	$(52,481)	$(81,065)	$383,185	$(3,560,683)	$(168,580)
Oil and gas properties	$1,497,727	$1,325,068	$1,010,466	$851,145	$3,878,937
Total assets	$1,733,288	$1,512,982	$1,540,928	$952,039	$4,225,690
Total debt, net(3)(4)	$2,215,481	$2,116,211	$—	$3,390,000	$3,378,000
Other long-term obligations	$211,895	$197,728	$177,088	$165,784	$152,472
Deferred income taxes, net	$—	$—	$—	$—	$992
Total shareholders' (deficit) equity	$(1,048,622)	$(1,154,636)	$(2,928,151)	$(2,991,937)	$211,660

(1) In conjunction with emergence from chapter 11 proceedings, the Company issued new common shares to holders of existing common shares at a conversion ratio of 0.521562. The earnings (loss) per share has been adjusted to reflect this conversion as if it had occurred on January 1, 2014.

(2) Cash flows from operating activities for the years ended December 31, 2016, 2015 and 2014, have been updated to reflect the retrospective application of the Company's adoption of ASU 2016-18.

(3) At December 31, 2016, $2.1 billion of long-term debt is included with liabilities subject to compromise on our Consolidated Balance Sheets.

(4) At December 31, 2018 and 2017, costs associated with the issuance of our long-term debt, excluding the costs associated with the Revolving Credit Facility are presented as a direct deduction from the carrying value of the related debt liability on the Consolidated Balance Sheet.

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

The following discussion and analysis should be read in conjunction with our consolidated financial statements and related notes thereto included elsewhere in this report. Further, we encourage you to revisit the Forward-Looking Statements section in Item 1A. “Risk Factors.”

Operations Overview

Production and Revenues

Ultra Petroleum Corp. is an independent exploration and production company focused on developing and producing its long-life natural gas reserves in the Pinedale and Jonah fields of the Green River Basin of southwest Wyoming. The Company operates in one industry segment, natural gas and oil exploration and development, with one geographical segment, the United States.

The Company conducts operations exclusively in the United States. Substantially all of its oil and natural gas activities are conducted jointly with others and, accordingly, amounts presented reflect only the Company’s proportionate interest in such activities. The Company continues to focus on improving its drilling and production results through gaining efficiencies with the use of advanced technologies, detailed technical analysis of its properties and leveraging its experience. Inflation has not had, nor is it expected to have in the foreseeable future, a material impact on the Company’s results of operations or capital investment program.

The Company currently generates its revenue, earnings and cash flow primarily from the production and sales of natural gas and condensate from its properties in southwest Wyoming. During the year ended December 31, 2018, the Company generated revenue from oil sales from properties in the Uinta Basin in Utah, which were sold during the third quarter of 2018.

During 2014, the Company acquired contracts to process NGLs beginning in 2017. During 2017, the Company renegotiated its existing gas processing contracts in Wyoming. The new gas processing contracts are keep-whole contracts in which the Company shares in the economic benefit of processing and accordingly does not include the NGL volumes in its reserves.

The prices of oil and natural gas are critical factors to the Company’s business. The prices of oil and natural gas have historically been volatile, and this volatility could be detrimental to the Company’s financial performance. As a result, and from time to time, the Company tries to limit the impact of this volatility on its results by entering into swap agreements and/or fixed price forward physical delivery contracts for natural gas and oil. The Company is required under its Revolving Credit Facility to enter into derivative commodity contracts for a minimum of 65% of its forecast proven producing natural gas reserves for the ensuing 18-month period. The Company has also begun to utilize more costless collars and is now utilizing put contracts, with low premium costs, to provide a degree of floor price protection and allow the Company to participate in more upward price exposure. (See Note 8).

The average price realization for the Company’s natural gas during 2018 was $2.48 per Mcf, including realized gains and losses on commodity derivatives. During the quarter ended December 31, 2018, the average price realization for the Company’s natural gas was $2.58 per Mcf, including realized gains and losses on commodity derivatives. The Company’s average price realization for natural gas, excluding realized gains and losses on commodity derivatives, was $2.77 per Mcf and $3.95 per Mcf for the year and the quarter ended December 31, 2018, respectively.

The average price realization for the Company's crude oil and condensate during 2018 was $59.44 per barrel, including realized gains and losses on commodity derivatives. During the quarter ended December 31, 2018, the average price realization for the Company's crude oil and condensate was $61.74 per barrel, including realized gains and losses on commodity derivatives. The Company's average price realization for crude oil and condensate, excluding realized gains and losses on commodity derivatives, was $62.88 per barrel and $58.30 per barrel for the year and the quarter ended December 31, 2018, respectively.

Capital Investments

The Company began 2018 with seven operated rigs running in the Pinedale field with a mix of planned activities on both vertical wells and horizontal wells. In the second quarter of 2018, the decision was made to assign all rigs to horizontal development. As the results for the horizontal development began to come in, the decision was made to reduce the number of rigs to four operated rigs and then subsequently to pause the horizontal drilling program and concentrate on vertical well development in Pinedale with a three operated rig program in the third quarter through the end of 2018. The total capital investment in oil and gas properties was $426.2 million and resulted in a total of 116 gross (86.0 net) vertical wells and 19 gross (14.4 net) horizontal wells which were drilled and cased in the Pinedale field.

The Company has paused its horizontal well program to evaluate the results of the program, perform additional sub-surface evaluation, and consider alternatives to its well design and completion techniques. As the Company continues to learn, it may incorporate a limited number of wells into the vertical program utilizing the existing three-rig fleet. The per well cost for the horizontal wells averaged $10.3 million per well in gross costs including facilities as of December 31, 2018. The vertical well costs began to come back to historical levels in the fourth quarter of 2018, where these costs averaged $3.1 million. This improvement from higher levels during 2018 was a reflection of more concentrated operations and the resulting efficiencies from development on larger drill pads resulting in less rig movement and a higher utilization rate of equipment as a result.

Liquidity and Working Capital

As of December 31, 2018, the Company had $17.0 million of cash and $104.0 million outstanding under its Revolving Credit Facility. The Revolving Credit Facility has availability up to $325.0 million, providing the Company $221.0 million of additional liquidity as of the end of the 2018. Subsequent to year-end, the Company reaffirmed it borrowing base at $1.3 million and entered into an amendment of its Revolving Credit Facility.

Working capital can be impacted by changes in the timing of receivables and payables. A significant item that impacted working capital as of December 31, 2018, was related to the timing of derivative settlements. A significant portion of our derivative settlements relate to fixed price natural gas and fixed price basis. The derivative settlements in the fourth quarter of 2018 were significant and also impacted our working capital. The timing of settlements for natural gas fixed price and basis is determined on the first of month pricing in the month of production. The natural gas basis settlement prices for December were significantly higher than the derivative contract price for that period. As a result, the settlement of the December 2018 derivative contracts for natural gas was $34.1 million and basis was $30.8 million and required a utilization of that amount in working capital and as borrowings under our Revolving Credit Facility. Conversely, the physical sales value for December 2018 of natural gas were accrued at the higher first of month price for a substantial portion of our December 2018 production and this amount was accrued as of December 31, 2018 as a receivable. The timing for collection of the receivable is approximately the 25th day of the month after the month of sale, resulting in an approximate 50-55 day lag in the matching of the cash flows between the settlement of the derivative contract and the physical sales. This can have a significant impact on month-to-month working capital. All amounts have been collected under the physical sales contracts and the utilization under the Revolving Credit Facility has been reduced subsequent to December 31, 2018.

As of February 28, 2019, the Company had a cash balance of approximately $6 million and $41 million due under the Revolving Credit Facility.

2018 Debt Exchange Transaction

In December 2018, the Company completed the Exchange Transaction, pursuant to which the exchanging noteholders exchanged (i) $505.0 million aggregate principal amount, or 72.1%, of the issued and outstanding 2022 Notes and (ii) $275.0 million aggregate principal amount, or 55.0%, of the issued and outstanding 2025 Notes for (a) $545.0 million aggregate principal amount of Senior Secured Second Lien Notes due July 2024 and (b) an aggregate of 10,919,499 new warrants of the Company each entitling the holder thereof to purchase one common share of the Company. This transaction resulted in a reduction of total principal indebtedness by approximately $235.0 million in December 2018. The Company evaluated the accounting treatment of the Exchange Transaction under ASC 470, Debt.

Subsequent to year-end, the Company has continued to execute follow-on exchanges of its 2022 Notes for Second Lien Notes, as allowed by the Second Lien Notes Indenture. Under the Second Lien Notes Indenture, the Company is permitted to exchange up to $55 million of 2022 Notes for Second Lien Notes at terms that are at or more favorable to the Company than the terms of the Exchange Transaction. Through February 28, 2019, the Company has exchanged an additional $44.6 million of 2022 Notes for approximately $27.0 million of Second Lien Notes, bringing the total reductions to debt from these exchanges to $252.5 million, inclusive of the Exchange Transaction. The Company will evaluate the treatment of the follow-on exchanges under the same accounting literature used in the Exchange Transaction. The Company continues to retain the ability under the Second Lien Notes Indenture to further exchange $10.4 million of the remaining 2022 Notes within one-year of the Exchange Transaction.

2017 Chapter 11 Proceedings

The Company emerged from chapter 11 proceedings during the year ended, December 31, 2017. The effects of the Plan (defined below) were included in the Consolidated Financial Statements as of December 31, 2017, and the related adjustments thereto were recorded in our Consolidated Statement of Operations as reorganization items for the twelve months ended December 31, 2017.

Voluntary Reorganization Under Chapter 11

On April 29, 2016, the Company and its subsidiaries (collectively, "the Debtors") filed voluntary petitions under chapter 11 of title 11 of the United States Code in the United States Bankruptcy Court for the Southern District of Texas (the "Bankruptcy Court"). Our chapter 11 cases were jointly administered under the caption In re Ultra Petroleum Corp., et al, (Case No. 16-32202 (MI). On March 14, 2017, the Bankruptcy Court confirmed our Debtors' Second Amended Joint Chapter 11 Plan of Reorganization (the "Plan") and on April 12, 2017 (the "Effective Date"), we emerged from bankruptcy. See Note 14 in the Notes to the Consolidated Financial Statements for further discussion of these matters.

Fresh Start Accounting

We were not required to apply fresh start accounting to our consolidated financial statements in connection with our emergence from bankruptcy because the reorganization value of our assets immediately prior to confirmation of the Plan exceeded our aggregate postpetition liabilities and allowed claims.

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Results of Operations — Year Ended December 31, 2018 vs. Year Ended December 31, 2017

	For the year ended December 31,		
	2018	2017	% change
	(Amounts in thousands, except per unit data)		
Production, Commodity Prices and Revenues:			
Production:			
Natural gas (Mcf)	260,406	260,009	0 %
Crude oil and condensate (Bbls)	2,442	2,775	-12 %
Total production (Mcfe)	275,058	276,659	-1 %
Commodity Prices:			
Natural gas ($/Mcf, incl realized hedges)	$2.48	$2.92	-15 %
Natural gas ($/Mcf, excluding hedges)	$2.77	$2.88	-4 %
Crude oil and condensate ($/Bbl, incl realized hedges)	$59.44	$48.05	24 %
Crude oil and condensate ($/Bbl, excluding hedges)	$62.88	$48.05	31 %
Revenues:			
Natural gas sales	$722,313	$748,682	-4 %
Oil sales	$153,534	$133,368	15 %
Other revenues	$16,652	$9,823	70 %
Total operating revenues	$892,499	$891,873	0 %
Derivatives:			
Realized gain (loss) on commodity derivatives	$(85,413)	$11,446	-846 %
Unrealized gain (loss) on commodity derivatives	$(59,799)	$16,966	-452 %
Total gain (loss) on commodity derivatives	$(145,212)	$28,412	-611 %
Operating Costs and Expenses:			
Lease operating expenses	$90,290	$92,326	-2 %
Facility lease expense	$25,947	$21,749	19 %
Production taxes	$93,322	$91,067	2 %
Gathering fees	$89,806	$86,953	3 %
Depletion, depreciation and amortization	$204,255	$161,945	26 %
General and administrative expenses	$25,005	$39,548	-37 %
Per Unit Costs and Expenses ($/Mcfe):			
Lease operating expenses	$0.33	$0.33	0 %
Facility lease expense	$0.09	$0.08	13 %
Production taxes	$0.34	$0.33	3 %
Gathering fees	$0.33	$0.31	6 %

Depletion, depreciation and amortization	$0.74	$0.59	25	%
General and administrative expenses	$0.09	$0.14	-36	%

Production, Commodity Prices and Revenues:

Production. During the year ended December 31, 2018, production slightly decreased on a gas equivalent basis to 275.1 Bcfe from 276.7 Bcfe for the same period in 2017. The decrease is primarily attributable to the sale of the non-core, predominately natural gas, assets in Pennsylvania during the fourth quarter of 2017 and non-core, predominately oil, assets in Utah during the third quarter of 2018.

Revenues. During the year ended December 31, 2018, revenues slightly increased to $892.5 million for the year ended December 31, 2018, as compared to $891.9 million in 2017. This increase is attributable to the increase in average oil prices, partially offset by the decrease in natural gas prices.

Commodity prices — natural gas. Realized natural gas prices, including realized gains and losses on commodity derivatives, decreased to $2.48 per Mcf during the year ended December 31, 2018 as compared to $2.92 per Mcf during 2017. This net realized price is a combination of the natural gas prices at Henry Hub and inclusive of our basis differentials at NwRox. The Company has open natural gas price commodity derivative contracts as of December 31, 2018. See Note 8 for additional details relating to these derivative contracts. During the year ended December 31, 2018, the Company's average price for natural gas, excluding realized gains and losses on commodity derivatives, was $2.77 per Mcf as compared to $2.88 per Mcf for the same period in 2017. The realized price during the year was fairly consistent; however, in the fourth quarter of 2018 the realized price for physical gas sales increased as a result of a pipeline outage supplying natural gas from Canada, among other things. Trades indicate that the basis differentials for the forward-looking basis market for 2019 and 2020 are negative to Henry Hub by approximately $0.30 and $0.46, respectively, highlighting potential volatility that can occur in our natural gas pricing.

Commodity prices — oil. Realized oil prices, including realized gains and losses on commodity derivatives, increased to $59.44 per barrel during the year ended December 31, 2018, as compared to $48.05 per barrel during 2017. The Company has open oil price commodity derivative contracts as of December 31, 2018. During the year ended December 31, 2018, the Company's average price for oil, excluding realized gains and losses on commodity derivatives, was $62.88 per barrel compared to $48.05 per barrel for the same period in 2017.

Operating Costs and Expenses:

Lease Operating Expense. Lease operating expenses ("LOE") decreased slightly to $90.3 million for the year ended December 31, 2018 compared to $92.3 million during the same period in 2017 due to a slight decrease in the overall well count which was a result of the Utah divesture in September 2018. While production from the Utah assets was minimal to the overall consolidated results, the Utah assets predominately produced oil and the LOE averaged $2.63 per Mcfe prior to the divesture. On a unit of production basis, consolidated LOE costs remained flat at $0.33 per Mcfe at December 31, 2018 and 2017.

Facility Lease Expense. In 2012, the Company sold a system of liquids gathering pipelines and central gathering facilities (the "Pinedale LGS") and certain associated real property rights in the Pinedale Anticline in Wyoming. The Company entered into a long-term, triple net lease agreement with the buyer relating to the use of the Pinedale LGS (the "Pinedale Lease Agreement"). For the year ended December 31, 2018, the Company recognized operating lease expense associated with the Pinedale Lease Agreement of $25.9 million, or $0.09 per Mcfe compared with $21.7 million, or $0.08 per Mcfe in 2017. This increase is a result of exceeding certain volume thresholds set forth in the original Pinedale Lease Agreement.

Production Taxes. During the year ended December 31, 2018, production taxes were $93.3 million compared to $91.1 million during the same period in 2017, or $0.34 per Mcfe in 2018, compared to $0.33 per Mcfe in 2017. Production taxes are primarily calculated based on a percentage of revenue from production in Wyoming after certain deductions and were 10.5% of revenues for the year ended 2018 and 10.2% for the same period in 2017. The increase in production taxes is primarily attributable to increased oil prices during the year December 31, 2018 as compared to the same period in 2017.

Gathering Fees. Gathering fees increased slightly to $89.8 million for the year ended December 31, 2018 compared to $87.0 million during the same period in 2017. This slight increase was mainly attributable to the higher costs incurred for trucking fees when disruptions on the oil pipeline occurred during the first half of 2018. On a per unit basis, gathering fees were $0.33 per Mcfe for the year ended December 31, 2018 as compared to $0.31 per Mcfe at December 31, 2017. Gathering fees during the second half of 2018 averaged $0.32 per Mcfe.

Depletion, Depreciation and Amortization. DD&A expenses increased to $204.3 million during the year ended December 31, 2018 from $161.9 million for the same period in 2017, attributable to the addition of proved undeveloped reserves and the associated capital as a result of the Company's emergence from chapter 11 proceedings in April 2017. On a unit of production basis, DD&A increased to $0.74 per Mcfe at December 31, 2018 from $0.59 per Mcfe at December 31, 2017.

General and Administrative Expenses. General and administrative expenses decreased to $25.0 million for the year ended December 31, 2018 compared to $39.5 million for the same period in 2017. The decrease in general and administrative expenses is primarily attributable to the stock incentive compensation expense that was incurred for the year ended December 31, 2017 as part of the 2017 Stock Incentive Plan. For the years ended December 31, 2018 and 2017, the Company recognized $10.9 million and $38.5 million, respectively, of pre-tax compensation expense related to the Initial MIP Grants as described in Note 7. On a per unit basis, general and administrative expenses decreased to $0.09 per Mcfe at December 31, 2018 from $0.14 per Mcfe at December 31, 2017.

Other Expenses. The Company recognized $9.1 million of other expenses for the year ended December 31, 2018, of which $4.9 million is attributable to the provision for uncollectible accounts and $4.2 million is attributable to the Houston office relocation. There were no other expenses incurred during the year ended December 31, 2017.

Other Income and Expenses:

Interest Expense. Interest expense decreased to $148.3 million during the year ended December 31, 2018 compared to $361.4 million during the same period in 2017. The decrease in interest expense is primarily attributable to the postpetition interest of $175.2 million recognized in 2017, related to the Bankruptcy Court order denying our objection to post-petition interest claims, at the default rate for the period beginning April 29, 2016 through April 12, 2017. Subsequent to December 31, 2018, the U.S. Court of Appeals for the Fifth Circuit issued an opinion vacating the order of the Bankruptcy Court denying our objection to the asserted make-whole and post-petition interest claims, and remanding the matter and those determinations to the Bankruptcy Court for further reconsideration. Refer to Note 15 for additional details regarding this appeal.

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Contract Settlement Income (Expense), Net. The Company recognized $12.7 million of net contract settlement income for the year ended December 31, 2018 compared to $52.7 million of contract settlement expense for the year ended December 31, 2017. In the fourth quarter of 2018, the Company entered into settlement agreements (collectively, the “Settlement Agreements”) with holders of certain claims related to Ultra Resources’ prepetition indebtedness (the “Claimants”) pursuant to which the parties agreed to settle the pending disputes between the Claimants and the Company. Under the terms of the Settlement Agreements, the Claimants collectively agreed to pay approximately $16.4 million to the Company. This was partially offset by fees associated with completing the Settlement Agreements. The Company will continue to pursue its appeal against all non-settled parties. In 2017, the Company reached a contract settlement of $57.0 million for a 2016 claim related to a transportation contract.

Deferred Gain on Sale of Liquids Gathering System. During the years ended December 31, 2018 and 2017, the Company recognized $10.6 million in deferred gain on sale of the liquids gathering system relating to the sale of the Pinedale LGS in 2012.

Commodity Derivatives:

Gain (Loss) on Commodity Derivatives. During the year ended December 31, 2018, the Company recognized a loss of $145.2 million related to commodity derivatives. Of this total, the Company recognized $85.4 million related to realized loss during the year ended December 31, 2018. The realized gain or loss on commodity derivatives relates to actual amounts received or paid under the Company’s derivative contracts. This gain or loss on commodity derivatives also includes a $59.8 million unrealized loss on commodity derivatives at December 31, 2018. The unrealized gain or loss on commodity derivatives represents the non-cash charge attributable to the change in the fair value of these derivative instruments over the remaining term of the contract.

Reorganization Items:

Reorganization Items, Net. Reorganization items, net were $140.9 million as of December 31, 2017 and was primarily consisted of expenses of $66.3 million in professional fees associated with the Company’s chapter 11 cases and $223.8 million related to the Bankruptcy Court order denying our objection to the make-whole claims offset by a gain of $431.1 million, which primarily represents the gain on the debt for equity exchange related to the Company’s prepetition senior notes.

Income from Operations:

Pretax Income. The Company recognized income before income taxes of $85.6 million for the year ended December 31, 2018 compared with income of $163.8 million for the same period in 2017. The decrease in earnings is primarily attributable to the loss recognized on the commodity derivatives as of December 31, 2018 compared to a gain that was recognized in the same period of 2017, and partially offset by the decrease in interest expense.

Income Taxes. The Company has recorded a $0.4 million tax expense for the year ended December 31, 2018 associated with the finalization of certain items from earlier periods. The Company has recorded a valuation allowance against all of its net deferred tax asset balance as of December 31, 2018. Some or all of this valuation allowance may be reversed in future periods against future income.

Net Income. For the year ended December 31, 2018, the Company recognized net income of $85.2 million or $0.43 per diluted share as compared with net income of $177.1 million or $1.08 per diluted share for the same period in 2017. The operating income and operating expense elements together with the loss on commodity derivatives, offset by the decreased interest expense were the primary elements for the decrease in earnings in 2018 as compared to 2017.

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Results of Operations — Year Ended December 31, 2017 vs. Year Ended December 31, 2016

	For the year ended December 31,			
	2017	2016	% change	
	(Amounts in thousands, except per unit data)			
Production, Commodity Prices and Revenues:				
Production:				
Natural gas (Mcf)	260,009	264,278	-2	%
Crude oil and condensate (Bbls)	2,775	2,912	-5	%
Total production (Mcfe)	276,659	281,748	-2	%
Commodity Prices:				
Natural gas ($/Mcf, incl realized hedges)	$2.92	$2.31	27	%
Natural gas ($/Mcf, excluding hedges)	$2.88	$2.31	25	%
Crude oil and condensate ($/Bbl, incl realized hedges)	$48.05	$38.24	26	%
Crude oil and condensate ($/Bbl, excluding hedges)	$48.05	$38.24	26	%
Revenues:				
Natural gas sales	$748,682	$609,756	23	%
Oil sales	$133,368	$111,335	20	%
Other revenue	$9,823	$—	100	%
Total operating revenues	$891,873	$721,091	24	%
Derivatives:				
Realized gain on commodity derivatives	$11,446	$—	100	%
Unrealized gain on commodity derivatives	$16,966	$—	100	%
Total gain on commodity derivatives	$28,412	$—	100	%
Operating Costs and Expenses:				
Lease operating expenses	$92,326	$89,134	4	%
Facility lease expense	$21,749	$20,686	5	%
Production taxes	$91,067	$69,737	31	%
Gathering fees	$86,953	$86,809	0	%
Transportation charges	$—	$20,049	-100	%
Depletion, depreciation and amortization	$161,945	$125,121	29	%
General and administrative expenses	$39,548	$9,179	331	%
Per Unit Costs and Expenses ($/Mcfe):				
Lease operating expenses	$0.33	$0.32	3	%
Facility lease expense	$0.08	$0.07	14	%
Production taxes	$0.33	$0.25	32	%

Gathering fees	$0.31	$0.31	0	%
Transportation charges	$—	$0.07	-100	%
Depletion, depreciation and amortization	$0.59	$0.44	34	%
General and administrative expenses	$0.14	$0.03	367	%

Production, Commodity Prices and Revenues:

Production. During the year ended December 31, 2017, production decreased on a gas equivalent basis to 276.7 Bcfe from 281.7 Bcfe for the same period in 2016. The decrease is primarily attributable to decreased capital investment during the year ended December 31, 2016.

Commodity prices — natural gas. Realized natural gas prices, including realized gains and losses on commodity derivatives, increased to $2.92 per Mcf during the year ended December 31, 2017 as compared to $2.31 per Mcf during 2016. The Company had open derivative contracts for natural gas production during 2017. During the year ended December 31, 2017, the Company's average price for natural gas excluding realized gains and losses on commodity derivatives was $2.88 per Mcf as compared to $2.31 per Mcf for the same period in 2016.

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Commodity prices — oil. During the year ended December 31, 2017, the average price realization for the Company's oil was $48.05 per barrel compared with $38.24 per barrel during 2016. The Company did not have any open derivative contracts for oil production during 2017 or 2016.

Revenues. The increase in average oil and natural gas prices partially offset by decreased total production resulted in revenues increasing to $891.9 million for the year ended December 31, 2017 as compared to $721.1 million in 2016.

Operating Costs and Expenses:

Lease Operating Expense. LOE increased to $92.3 million for the year ended December 31, 2017 compared to $89.1 million during the same period in 2016 largely related to the increase in producing well counts. On a unit of production basis, LOE costs increased to $0.33 per Mcfe at December 31, 2017 compared to $0.32 per Mcfe at December 31, 2016.

Facility Lease Expense. For the year ended December 31, 2017, the Company recognized operating lease expense associated with the Pinedale Lease Agreement of $21.7 million, or $0.08 per Mcfe compared with $20.7 million, or $0.07 per Mcfe in 2016.

Production Taxes. During the year ended December 31, 2017, production taxes were $91.1 million compared to $69.7 million during the same period in 2016, or $0.33 per Mcfe in 2017, compared to $0.25 per Mcfe in 2016. Production taxes are primarily calculated based on a percentage of revenue from production in Wyoming and Utah after certain deductions and were 10.2% of revenues for the year ended 2017 and 9.7% for the same period in 2016. The increase in production taxes is primarily attributable to increased oil and natural gas prices during the year December 31, 2017, and the higher relative contribution of Wyoming production in 2017 than as compared to the same period in 2016.

Gathering Fees. Gathering fees increased slightly to $87.0 million for the year ended December 31, 2017 compared to $86.8 million during the same period in 2016. On a per unit basis, gathering fees remained flat at $0.31 per Mcfe for the years ended December 31, 2017 and 2016.

Transportation Charges. As a result of the termination of our contract with Rockies Express Pipeline LLC ("REX") during the first quarter of 2016, there were no material transportation charges for the year ended December 31, 2017. Transportation charges were $20.0 million for the year ended December 31, 2016.

Depletion, Depreciation and Amortization. DD&A expenses increased to $161.9 million during the year ended December 31, 2017 from $125.1 million for the same period in 2016, attributable to the addition of "PUDs" as a result of the Company's emergence from chapter 11 proceedings in April 2017. On a unit of production basis, DD&A increased to $0.59 per Mcfe at December 31, 2017 from $0.44 per Mcfe at December 31, 2016.

General and Administrative Expenses. General and administrative expenses increased to $39.5 million for the year ended December 31, 2017 compared to $9.2 million for the same period in 2016. The increase in general and administrative expenses is primarily attributable to the non-cash stock incentive compensation expense that was incurred as part of the Ultra Petroleum Corp. 2017 Stock Incentive Plan, in which tranche one became fully vested on the Effective Date. On a per unit basis, general and administrative expenses increased to $0.14 per Mcfe at December 31, 2017 from $0.03 per Mcfe at December 31, 2016.

Other Income and Expenses:

Interest Expense. Interest expense increased to $361.4 million during the year ended December 31, 2017 compared to $66.6 million during the same period in 2016. The change in interest expense is comprised of $85.8 million of accrued postpetition interest for the period beginning April 29, 2016 through April 12, 2017, $100.4 million of interest expense incurred on the Revolving Credit Facility, Term Loan Facility, and the Unsecured Notes (see Note 6 for additional details), and $175.2 million for postpetition interest, related to the Bankruptcy Court order denying our objection to postpetition interest claims, at the default rate for the period beginning April 29, 2016 through April 12, 2017, as described in Note 12.

Restructuring Expense. During the year ended December 31, 2016, the Company incurred $7.2 million in costs and fees in connection with its efforts to restructure its debt prior to filing the chapter 11 petitions.

Contract Settlement. Contract settlement expense decreased to $52.7 million for the year ended December 31, 2017, compared to $131.1 million for the year ended December 31, 2016. The decrease relates to the contract settlement of $57.0 million reached with Sempra Rockies Marketing, LLC during the year ended December 31, 2017 as compared to the contract settlement of $150.0 million reached with REX during the year ended December 31, 2016.

Deferred Gain on Sale of Liquids Gathering System. During the years ended December 31, 2017 and 2016, the Company recognized $10.6 million in deferred gain on sale of the liquids gathering system relating to the Pinedale LGS in December 2012.

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Commodity Derivatives:

Gain (Loss) on Commodity Derivatives. During the year ended December 31, 2017, the Company recognized a gain of $28.4 million related to commodity derivatives. Of this total, the Company recognized $11.4 million of realized gain during the year ended December 31, 2017. The realized gain or loss on commodity derivatives relates to actual amounts received or paid under the Company's derivative contracts. This gain on commodity derivatives also includes a $17.0 million of unrealized gain on commodity derivatives at December 31, 2017. The unrealized gain or loss on commodity derivatives represents the change in the fair value of these derivative instruments over the remaining term of the contract. The Company did not have any open commodity derivatives at December 31, 2016.

Reorganization Items:

Reorganization Items, Net. Reorganization items, net represented an income of $140.9 million for the year ended December 31, 2017 compared to an expense of $47.5 million for the same period in 2016. The increase is due to the Company's emergence from chapter 11 proceedings during the year ended December 31, 2017, and is primarily comprised of expenses of $66.4 million in professional fees, settlements, and interest income associated with the Company's chapter 11 cases and of $223.8 million related to the Bankruptcy Court order denying our objection to the make-whole claims offset by a gain of $431.1 million, which primarily represents the gain on the debt for equity exchange related to the Company's prepetition senior notes.

Income from Operations:

Pretax Income. The Company recognized income before taxes of $163.8 million for the year ended December 31, 2017 compared with income of $55.5 million for the same period in 2016. The increase in earnings is primarily attributable to increased revenues due to increases in the average oil and natural gas prices and the net effect of the reorganization items, partially offset by an increase in interest expense, DD&A, and general and administrative expense during the year ended December 31, 2017.

Income Taxes. The Company recorded a $13.3 million tax benefit related to expected U.S. cash tax refunds for the year ended December 31, 2017. The Company has recorded a valuation allowance against substantially all of its net deferred tax asset balance as of December 31, 2017. Some or all of this valuation allowance may be reversed in future periods against future income.

Net Income. For the year ended December 31, 2017, the Company recognized a net income of $177.1 million or $1.08 per diluted share as compared with a net income of $56.2 million or $0.70 per diluted share for the same period in 2016. The increase in earnings is primarily attributable to increased revenues due to increases in the average oil and natural gas prices and the net effect of the reorganization items, partially offset by an increase in interest expense, DD&A, and general and administrative expense during the year ended December 31, 2017.

LIQUIDITY AND CAPITAL RESOURCES

Overview. During the year ended December 31, 2018, we funded our operations primarily through cash flows from operating activities and borrowings under the Revolving Credit Facility. In addition to cash flows from operations, the Revolving Credit Facility is our primary source of liquidity. At December 31, 2018, the Company reported a cash position of $17.0 million. At December 31, 2018, the Company had $104.0 million of outstanding borrowings under the Revolving Credit Facility. In addition to the borrowings outstanding under the Revolving Credit Facility, the Company had $1.9 billion of other indebtedness outstanding in the form of term loans, secured notes and unsecured notes with maturities commencing in 2022. The borrowing base provides for a total of $325.0 million of availability. Availability may be limited based on compliance with financial covenants; however, subsequent to the Fourth Amendment to the Credit Agreement dated February 14, 2019, the Company expects to have adequate liquidity to fund its operations into the foreseeable future.

Given the current level of volatility in the market and unpredictability of certain costs that could potentially arise in our operations, the Company’s liquidity needs could be significantly higher than the Company currently anticipates. The Company’s ability to maintain adequate liquidity depends on the prevailing market prices for oil and natural gas, the successful operation of the business, and appropriate management of operating expenses and capital spending. The Company’s anticipated liquidity needs are highly sensitive to changes in each of these and other factors.

Capital Expenditures. For the year ended December 31, 2018, total capital expenditures were $426.2 million. During this period, the Company participated in 135 gross (100.5 net) wells in Wyoming that were drilled to total depth and cased. No wells were drilled in Utah during 2018.

2019 Capital Investment Plan. For 2019, our capital expenditures are expected to be approximately $320 million to $350 million, including capitalized general and administrative costs. We expect to fund these capital expenditures through cash flows from operations, borrowings under the Revolving Credit Facility, and cash on hand. We expect to allocate all of the budget to development activities in our Pinedale field.

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Ultra Resources, Inc.

Credit Agreement. On April 12, 2017, Ultra Resources, as the borrower, entered into a Credit Agreement (the “Credit Agreement”) with the Company and UP Energy Corporation, as parent guarantors, with Bank of Montreal, as administrative agent (the “RBL Administrative Agent”), and with the other lenders party thereto (collectively, the “RBL Lenders”) from time to time, providing for a revolving credit facility (the “Revolving Credit Facility”) subject to borrowing base redetermination which limits the aggregate amount of first lien debt under the Revolving Credit Facility and Term Loan Agreement (as defined below). In September 2018, the borrowing base was reduced from $1.4 million to $1.3 billion in connection with the semi-annual determination, with $975.0 million allocated to the Company’s Term Loan Facility (defined below), resulting in $325.0 million of borrowing base under the Revolving Credit Facility as of the end of 2018.

On December 21, 2018, in connection with the consummation of the Exchange Transaction, Ultra Resources and the parent guarantors entered into the Third Amendment to the Credit Agreement (the “Third Amendment”) with the RBL Administrative Agent and the RBL Lenders party thereto. Pursuant to the Third Amendment, the parties agreed, among other things, to amend the Credit Agreement to permit the issuance of the Second Lien Notes and the Exchange Transaction and to revise certain covenants and other provisions of the Credit Agreement, including, but not limited to:

- increasing collateral coverage from 85% to 95% of total PV-9 of Proven Reserves (as defined in the Credit Agreement);
- removing the ability to create, invest in and utilize unrestricted subsidiaries;
- further limiting the Company’s ability to incur unsecured debt, repay junior debt, and make restricted payments and investments as more thoroughly described in the Third Amendment; and
- providing the ability for the Company to exchange unsecured borrowings to third lien debt within a construct as described in the Third Amendment.

In conjunction with the Exchange Transaction, the Third Amendment was evaluated under FASB ASC 470-50-40, Debt Modifications and Extinguishments specifically for modifications to or exchanges of revolving-debt arrangements. Based on the guidance, the unamortized deferred costs, any fees paid to the creditor, and any third-party costs associated with Third Amendment, which were incurred as part of the Exchange Transaction, will be deferred and amortized over the term of the Credit Agreement because the borrowing capacity did not change. Deferred financing costs, including the new costs incurred as part of the Exchange Transaction, are recorded as Other assets on the Consolidated Balance Sheets in accordance with ASU No. 2015-15.

On February 14, 2019, Ultra Resources entered into a Fourth Amendment to the Credit Agreement (the “Fourth Amendment”) with the RBL Administrative Agent and the RBL Lenders party thereto. Pursuant to the Fourth Amendment, the borrowing base was reaffirmed at $1.3 billion with $325 million of borrowing base available under the Revolving Credit Facility.

The Fourth Amendment also revises certain covenants and other provisions of the Credit Agreement, including, but not limited to:

- Amending the consolidated net leverage ratio financial covenant as described below. In addition, the consolidated net debt component of the consolidated net leverage ratio may be reduced upon the receipt of proceeds from the make-whole litigation;
- Revising the definition of EBITDAX to (i) provide Ultra Resources with the option of whether to add back certain noncash charges that represent an accrual or reserve for potential cash items in a future period, (ii) provide for the

add back of costs and expenses with respect to senior management changes and office closure, consolidation and relocation, (iii) provide for the add back of costs and expenses with respect to debt restructuring activities (whether consummated or not), (iv) exclude from the deductions certain noncash gains that represent the reversal of an accrual or reserve for any anticipated cash charges in any prior period, and (v) provide for a deduction of cash payments with respect to certain noncash charges that Ultra Resources chose to add back (as described in clause (i)); and

- Amending the Current Ratio financial covenant to exclude from the consolidated current liabilities calculated thereunder, current required amortization payments under the Term Loan Agreement.

At December 31, 2018, Ultra Resources had $104.0 million of outstanding borrowings under the Revolving Credit Facility, total commitments under the Revolving Credit Facility of $325.0 million, and a borrowing base of $1.3 billion. Given that the Revolving Credit Facility was amended in February 2019 and the borrowing base was reaffirmed therein, the next scheduled borrowing base redetermination date is October 1, 2019.

The Revolving Credit Facility has capacity for Ultra Resources to increase the commitments subject to certain conditions and has $50.0 million of the commitments available for the issuance of letters of credit. The Revolving Credit Facility bears interest either at a rate equal to (a) a customary London interbank offered rate plus an applicable margin that varies from 250 to 350 basis points or (b) the base rate plus an applicable margin that varies from 150 to 250 basis points. If borrowings are outstanding during a period that the Company’s consolidated net leverage ratio exceeds 4.00 to 1.00 at the end of any fiscal quarter as described below, the interest rate on such borrowings shall be at a per annum rate that is 0.25% higher than the rate that would otherwise apply until the Company has provided financial statements indicating that the consolidated net leverage ratio no longer exceeds 4.00 to 1.00. The Revolving Credit Facility loans mature on January 12, 2022.

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Under the Fourth Amendment, Ultra Resources is required to maintain (i) a minimum interest coverage ratio of 2.50 to 1.00; (ii) a current ratio, including the unused portion of the Revolving Credit Facility, of a minimum of 1.00 to 1.00; and (iii) after the Company has obtained investment grade rating an asset coverage ratio of 1.50 to 1.00. In addition, as of the last day of (i) the fiscal quarter ending December 31, 2018, Ultra Resources will not permit the consolidated net leverage ratio to exceed 4.50 to 1.0, (ii) each fiscal quarter ending during the period from March 31, 2019 through June 30, 2019, Ultra Resources will not permit the consolidated net leverage ratio to exceed 4.75 to 1.0, (iii) each fiscal quarter ending during the period from September 30, 2019 through June 30, 2020, Ultra Resources will not permit the consolidated net leverage ratio to exceed 4.90 to 1.0, (iv) the fiscal quarter ending September 30, 2020, Ultra Resources will not permit the consolidated net leverage ratio to exceed 4.5 to 1.0, and (v) the fiscal quarter ending December 31, 2020 and each other fiscal quarter end thereafter, Ultra Resources will not permit the consolidated net leverage ratio to exceed 4.25 to 1.0.

At December 31, 2018, Ultra Resources' consolidated net leverage ratio, as defined in the Credit Agreement, was 3.95 to 1.00, and it was in compliance with each of its debt covenants under the Revolving Credit Facility.

Under the Revolving Credit Facility, the Company is subject to minimum hedging requirements. Through September 29, 2019, the Company is required to hedge a minimum of 65% of the quarterly projected volumes of natural gas from its proved developed producing ("PDP") reserves; and during the period beginning on September 30, 2019 and ending on March 30, 2020, the Company is required to hedge a minimum of 50% of the quarterly projected volumes of natural gas from PDP reserves. Beginning April 1, 2020, the Company will no longer be subject to a minimum hedging requirement.

Ultra Resources is required to pay a commitment fee on the average daily unused portion of the Revolving Credit Facility, which varies based upon a borrowing base utilization grid. Ultra Resources is also required to pay customary letter of credit and fronting fees.

The Revolving Credit Facility also contains customary affirmative and negative covenants, including, among other things, as to compliance with laws (including environmental laws, ERISA and anti-corruption laws), delivery of quarterly and annual financial statements and oil and gas engineering reports, maintenance and operation of property (including oil and gas properties), restrictions on the incurrence of liens, indebtedness, asset dispositions, fundamental changes, restricted payments, hedging requirements and other customary covenants.

The Revolving Credit Facility contains customary events of default and remedies for credit facilities of this nature. If Ultra Resources does not comply with the financial and other covenants in the Revolving Credit Facility, the lenders may, subject to customary cure rights, require immediate payment of all amounts outstanding under the Revolving Credit Facility and any outstanding unfunded commitments may be terminated.

Term Loan. On April 12, 2017, Ultra Resources, as borrower, entered into a Senior Secured Term Loan Agreement (the "Term Loan Agreement") with the Company and UP Energy Corporation, as parent guarantors, Barclays Bank PLC, as administrative agent (the "Term Loan Administrative Agent"), and the other lenders party thereto (collectively, the "Term Loan Lenders"), providing for senior secured first lien term loans for an aggregate amount of $800.0 million consisting of an initial term loan in the amount of $600.0 million and an incremental term loan in the amount of $200.0 million to be drawn immediately after the funding of the initial term loan. In September 2017, the Company closed an incremental senior secured term loan offering of $175.0 million, increasing total borrowings under the Term Loan Agreement to $975.0 million. As part of the Term Loan Agreement, Ultra Resources agreed to pay an original issue discount equal to one percent of the principal amount, which is included in the deferred financing costs.

On December 21, 2018, in connection with the consummation of the Exchange Transaction, Ultra Resources and the parent guarantors entered into the First Amendment to the Term Loan Agreement (the "Term Loan Amendment") with the Term Loan Administrative Agent and the Term Loan Lenders party thereto. Pursuant to the Term Loan Amendment, the parties agreed, among other things, to amend the Term Loan Agreement to permit the issuance of the Second Lien Notes and the Exchange Transaction, to increase the interest rate payable by 100 basis points, such increase comprising 75 basis points payable in cash and 25 basis points payable in kind ("PIK"), and to revise certain covenants and other provisions of the Term Loan Agreement, including, but not limited to:

- introducing call protection of 102% until the first anniversary of the Exchange Transaction and 101% until the second anniversary of the Exchange Transaction (defined below);
- introducing additional restrictions on the Revolving Credit Facility; including amendments and refinancing of the Revolving Credit Facility as more thoroughly described in the Term Loan Amendment;
- deleting the ability to increase commitments under the Term Loan;
- increasing collateral coverage from 85% to 95% of total PV-9 of Proven Reserves (as defined in the Term Loan Agreement);
- removing the ability to create, invest in and utilize unrestricted subsidiaries;
- further limiting the Company's ability to incur unsecured debt, repay junior debt, and make restricted payments and investments as more thoroughly described in the Term Loan Amendment; and
- providing the ability for the Company to exchange unsecured borrowings to third lien debt within a construct as described in the Term Loan Amendment.

At December 31, 2018, Ultra Resources had $975.0 million in outstanding borrowings under the Term Loan Facility.

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Following the Exchange Transaction, the Term Loan Facility bears interest either at a rate equal to (a) a customary London interbank offered rate plus 400 basis points or (b) the base rate plus 300 basis points, in each case, of which 25 basis points of the applicable margin is payable in- kind upon election by Ultra Resources. The Term Loan Facility amortizes in equal quarterly installments in aggregate annual amounts equal to 0.25% of the aggregate principal amount beginning on June 30, 2019. The Term Loan Facility matures on April 12, 2024.

In conjunction with the Exchange Transaction, the Term Loan Amendment was evaluated under FASB ASC 470-50-40, Debt Modifications and Extinguishments. The instrument was determined to not be substantially different and debt modification accounting was applied as this transaction was not a troubled debt restructuring ("TDR"), as defined in the accounting literature. As a result, no gain or loss was recorded. New fees paid to the Term Loan Lenders totaled $7.2 million and are included as deferred financing costs which is direct deduction from the carrying amount of the Term Loan.

The Term Loan Facility is subject to mandatory prepayments and customary reinvestment rights. The mandatory prepayments include, without limitation, a prepayment requirement with the total net proceeds from certain asset sales and net proceeds on insurance received on account of any loss of Ultra Resources' property or assets, in each case subject to certain exceptions. In addition, subject to certain exceptions, there is a prepayment requirement if the asset coverage ratio is less than 2.0 to 1.0. To the extent any mandatory prepayments are required, prepayments are applied to prepay the Term Loan Facility.

The Term Loan Agreement also contains customary affirmative and negative covenants, including as to compliance with laws (including environmental laws, ERISA and anti-corruption laws), delivery of quarterly and annual financial statements and oil and gas engineering reports, maintenance and operation of property (including oil and gas properties), restrictions on the incurrence of liens, indebtedness, asset dispositions, fundamental changes, restricted payments and other customary covenants. At December 31, 2018, Ultra Resources was in compliance with all of its debt covenants under the Term Loan Agreement.

The Term Loan Agreement contains customary events of default and remedies for credit facilities of this nature. If Ultra Resources does not comply with the financial and other covenants in the Term Loan Agreement, the lenders may, subject to customary cure rights, require immediate payment of all amounts outstanding under the Term Loan Agreement.

Second Lien Notes. On December 21, 2018, in connection with the consummation of the Exchange Transaction, Ultra Resources issued $545.0 million aggregate principal amount of Second Lien Notes and entered into an Indenture, dated as of December 21, 2018 (the "Second Lien Notes Indenture"), among Ultra Resources, as issuer, the Company and its other subsidiaries, as guarantors, and Wilmington Trust, National Association, as trustee (the "Trustee") and collateral agent.

The Second Lien Notes will mature on July 12, 2024. Interest on the Second Lien Notes will accrue at (i) an annual rate of 9.00% payable in cash and (ii) an annual rate of 2.00% PIK. The interest payment dates for the Second Lien Notes are January 15 and July 15 of each year, commencing on July 15, 2019.

The Second Lien Notes are senior secured obligations of Ultra Resources and rank senior in right of payment to all of its existing and future unsecured senior debt, to the extent of the value of the collateral pledged under the Second Lien Notes Indenture and related collateral arrangements, senior in right of payment to all of its future subordinated debt, and junior in right of payment to all of its existing and future secured debt of senior priority, to the extent of the value of the collateral pledged thereby. The Second Lien Notes are secured by second priority security interests in substantially all assets of the Company. Payment by Ultra Resources of all amounts due on or in respect of the Second Lien Notes and the performance of Ultra Resources under the Second Lien Notes Indenture are initially guaranteed by the Company.

Prior to December 21, 2021, Ultra Resources may, at any time or from time to time, redeem in the aggregate up to 35% of the aggregate principal amount of the Second Lien Notes in an amount no greater than the net cash proceeds of certain equity offerings at a redemption price of 111.000% of the principal amount of the Second Lien Notes, plus accrued and unpaid interest (including PIK interest), if any, to the date of redemption, if at least 65% of the original principal amount of the Second Lien Notes remains outstanding and the redemption occurs within 180 days of the closing of such equity offering. In addition, before December 21, 2019, Ultra Resources may redeem all or a part of the Second Lien Notes at a redemption price equal to the sum of (i) the principal amount thereof, plus (ii) a make-whole premium at the redemption date, plus accrued and unpaid interest (including PIK interest), if any, to the redemption date. In addition, on or after December 21, 2021, Ultra Resources may redeem all or a part of the Second Lien Notes at redemption prices (expressed as percentages of principal amount) equal to 105.500% for the twelve-month period beginning on December 21, 2021, 102.750% for the twelve-month period beginning December 21, 2022, and 100.000% for the twelve-month period beginning December 21, 2023 and at any time thereafter, plus accrued and unpaid interest (including PIK interest), if any, to the applicable redemption date on the Second Lien Notes.

If Ultra Resources experiences certain change of control triggering events set forth in the Second Lien Notes Indenture, each holder of the Second Lien Notes may require the Issuer to repurchase all or a portion of its Second Lien Notes for cash at a price equal to 101% of the aggregate principal amount of such Second Lien Notes, plus any accrued but unpaid interest (including PIK interest) to the date of repurchase.

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The Second Lien Notes Indenture contains customary covenants that restrict the ability of Ultra Resources and the guarantors and certain of its subsidiaries to: (i) sell assets and subsidiary equity; (ii) incur or redeem indebtedness; (iii) create or incur certain liens; (iv) enter into affiliate agreements; (v) pay cash dividends, (vi) change the nature of its business or operations, (vii) make certain types of investments, (ix) enter into agreements that restrict distributions from certain restricted subsidiaries and the consummation of mergers and consolidations; (x) consolidate, merge or transfer all or substantially all of the assets of the Company or any Restricted Subsidiary (as defined in the Second Lien Notes Indenture); and (xi) create unrestricted and foreign subsidiaries. The covenants in the Second Lien Notes Indenture are subject to important exceptions and qualifications. Subject to conditions, the Second Lien Notes Indenture provides that the Company and its subsidiaries will no longer be subject to certain covenants when the Second Lien Notes receive investment grade ratings from any two of S&P Global Ratings, Moody's Investors Service, Inc., and Fitch Ratings, Inc.

The Second Lien Notes Indenture contains customary events of default. Unless otherwise noted in the Second Lien Notes Indenture, upon a continuing event of default, the Trustee, by notice to the Company, or the holders of at least 25% in principal amount of the then outstanding Second Lien Notes, by notice to the Company and the Trustee, may declare the Second Lien Notes immediately due and payable, except that an event of default resulting from entry into a bankruptcy, insolvency or reorganization with respect to the Company, any Significant Subsidiary (as defined in the Second Lien Notes Indenture) or group of Restricted Subsidiaries (as defined in the Second Lien Notes Indenture), that taken together would constitute a Significant Subsidiary, will automatically cause the Second Lien Notes to become due and payable.

In conjunction with the Exchange Transaction, the portion of the senior Unsecured Notes which were exchanged for Second Lien Notes was accounted for as a TDR. The Company evaluated the quantitative and qualitative factors in the accounting literature and concluded that concessions were granted as the future undiscounted cash flows of the Second Lien Notes was greater than the net carrying value of the senior Unsecured Notes. No gain is recognized, and an effective interest rate is established based on the carrying value of the original Second Lien Notes and revised cash flows. The amount of extinguished debt will be amortized over the remaining life of the Second Lien Notes using the effective interest method and recognized as a reduction to interest expense. As a result, our reported interest expense following the Exchange Transaction will be significantly less than the contractual cash interest payments throughout the term of the Second Lien Notes.

The Exchange Transaction for the Second Lien Notes resulted in recognition of $4.7 million in expenses for the year ended December 31, 2018.

The exchanged debt resulted in a calculation of cancellation of debt income for tax purposes. Our current tax attributes are expected to offset any potential cash tax impacts from the Exchange Transaction.

Senior Unsecured Notes. On April 12, 2017, Ultra Resources issued $700.0 million of its 2022 Notes $500.0 million of its 2025 Notes and entered into an Indenture, dated April 12, 2017 (the "Unsecured Notes Indenture"), among Ultra Resources, as issuer, the Company and its other subsidiaries, as guarantors, and Wilmington Trust, National Association, as Trustee. The Unsecured Notes are treated as a single class of securities under the Unsecured Notes Indenture.

On December 21, 2018, the Company completed the Exchange Transaction, pursuant to which the exchanging noteholders exchanged (i) $505 million aggregate principal amount, or 72.1%, of the issued and outstanding 2022 Notes and (ii) $275 million aggregate principal amount, or 55.0%, of the issued and outstanding 2025 Notes for (a) $545.0 million aggregate principal amount of Second Lien Notes and (b) an aggregate of 10,919,499 new warrants of the Company each entitling the holder thereof to purchase one common share of the Company. As a result of the Exchange Transaction, at December 31, 2018, the aggregate principal amounts outstanding under the Unsecured Notes were approximately $195.0 million with respect to the 2022 Notes and $225.0 million with respect to the 2025 Notes.

The 2022 Notes will mature on April 15, 2022. The interest payment dates for the 2022 Notes are April 15 and October 15 of each year. The 2025 Notes will mature on April 15, 2025. The interest payment dates for the 2025 Notes are April 15 and October 15 of each year. Interest will be paid on the Unsecured Notes from the issue date until maturity.

On December 21, 2018, in connection with the consummation of the Exchange Transaction, Ultra Resources, the Company and its other subsidiaries, as guarantors, and the Trustee entered into the First Supplement Indenture to the Unsecured Indenture (the "Supplemental Indenture"). Pursuant to the Supplemental Indenture, the parties amended the Unsecured Indenture to, among other things, eliminate or amend substantially all of the restrictive covenants contained in the Unsecured Indenture, other than those relating to the payment of principal and interest. The Supplemental Indenture is binding on all Unsecured Notes that remain outstanding.

The Unsecured Notes Indenture contains customary events of default. Unless otherwise noted in the Unsecured Notes Indenture, upon a continuing event of default, the Trustee, by notice to the Company, or the holders of at least 25% in principal amount of the then outstanding Unsecured Notes, by notice to the Company and the Trustee, may, declare the Unsecured Notes immediately due and payable, except that an event of default resulting from entry into a bankruptcy, insolvency or reorganization with respect to the Company, any Significant Subsidiary (as defined in the Unsecured Notes Indenture) or group of Restricted Subsidiaries (as defined in the Unsecured Notes Indenture), that taken together would constitute a Significant Subsidiary, will automatically cause the Unsecured Notes to become due and payable.

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Cash flows provided by (used in):

Operating Activities. During the year ended December 31, 2018, net cash provided by operating activities was $310.9 million, a 376% increase from net cash provided by operating activities of $65.3 million for the same period in 2017. The increase in net cash provided by operating activities was largely attributable to the payment of postpetition interest claims during the year ended December 31, 2017, as well as changes to working capital. There were no postpetition interest payments during the year ended December 31, 2018.

Investing Activities. During the year ended December 31, 2018, net cash used in investing activities was $401.7 million as compared to $435.3 million for the same period in 2017. The decrease in net cash used in investing activities is largely related to decreased capital investments associated with the Company's drilling activities, partially offset by proceeds from the sale of certain non-core properties in Pennsylvania and Utah during 2017 and 2018, respectively.

Financing Activities. During the year ended December 31, 2018, net cash provided by financing activities was $91.8 million as compared to net cash used in financing activities of $16.7 million for the same period in 2017. The change in net cash used in financing activities is primarily due to the borrowings on the Credit Agreement as of December 31, 2018.

Outlook

While our net cash provided by operating activities will continue to be impacted by changing commodity prices, we believe that we will generate positive cash flow from operations, which, along with our available cash and available borrowing capacity, will provide sufficient liquidity to fund our capital investments and operations over the next twelve months. We will continue to monitor and evaluate the impact of commodity prices in order to determine the appropriate size and nature of our capital investment program.

We expect to rely on our available cash, existing credit facility, and the cash generated from operations to meet our obligations. While we continue to monitor the overall health of the credit markets, a renewed, long-term disruption in the credit markets could make financing more expensive or unavailable, which could have a material adverse effect on our operations.

Off-Balance Sheet Arrangements

The Company did not have any off-balance sheet arrangements as of December 31, 2018.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2018:

	Payments due by period:				
	Total	Less than	1 to 3 years	3 to 5 years	More than

		1 year			5 years
	(Amounts in thousands of U.S. dollars)				
Long-term debt	$2,044,035	$7,313	$19,500	$318,535	$1,698,687
Interest payments [1]	797,361	146,860	280,394	259,784	110,323
Transportation contract (REX)	189,968	2,277	53,626	53,626	80,439
Operating lease — Liquids Gathering System	195,729	21,748	43,495	43,495	86,991
Office space lease	3,903	1,251	2,070	582	—
Total contractual obligations	$3,230,996	$179,449	$399,085	$676,022	$1,976,440

[1] Interest payments include projected interest payments based on the variable interest rates which were calculated assuming a 3-month London interbank offered rate plus the applicable basis points as of December 31, 2018.

Outstanding debt and interest payments: The Company has debt financing agreements consisting of the Term Loan Facility, the Second Lien Notes, the Unsecured Notes, and the Revolving Credit Facility. See Note 6 for additional details. The Company included the principal and interest obligations above based on the respective agreements.

Transportation contract. During our chapter 11 proceedings, REX filed a claim against us for $303.3 million for breach of contract. As previously disclosed, on January 12, 2017, we agreed to settle their claim and paid the settlement amounts of $150.0 million during the year ended December 31, 2017. In connection with the settlement of REX's proof of claim, the Company agreed to enter into a new transportation agreement pursuant to which the Company will have firm transportation capacity of 200,000 Dekatherms per day at a rate of approximately $0.37 per Dekatherm on the Rockies Express Pipeline, commencing on December 1, 2019 and extending for a term expiring December 31, 2026. This new agreement will provide the Company with the opportunity to transport a portion of its natural gas production away from its properties in Wyoming to capture improved basis differentials available at sales points along the Rockies Express Pipeline, if any.

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Operating lease. In 2012, the Company sold the Pinedale LGS and certain associated real property rights in the Pinedale Anticline in Wyoming. The Company entered into a long-term, triple net lease agreement relating to the use of the Pinedale LGS. The Pinedale Lease Agreement provides for an initial term of 15 years and potential successive renewal terms of 5 years or 75% of the then remaining useful life of the Pinedale LGS at the sole discretion of the Company. Annual rent for the initial term under the Pinedale Lease Agreement is $20.0 million (as adjusted annually for changes based on the consumer price index) and may increase when certain volume thresholds are exceeded. The lease is classified as an operating lease under ASC 840 Leases.

All of the Company's lease obligations are related to leases that are classified as operating leases. These leases contain certain provisions that could result in accelerated lease payments. The Company has considered the effect of these provisions on minimum lease payments in its lease classification analysis and has determined that the default provisions do not impact classification of any the Company's operating leases.

Office space lease. The Company maintains office space in Colorado and Wyoming with total remaining commitments for office leases of $3.9 million at December 31, 2018.

Critical Accounting Policies

The discussion and analysis of the Company's financial condition and results of operations is based upon consolidated financial statements, which have been prepared in accordance with U.S. GAAP. In addition, application of GAAP requires the use of estimates, judgments and assumptions that affect the reported amounts of assets and liabilities as of the date of the financial statements as well as the revenues and expenses reported during the period. Changes in these estimates related to judgments and assumptions will occur as a result of future events, and, accordingly, actual results could differ from amounts estimated. Set forth below is a discussion of the critical accounting policies used in the preparation of our financial statements which we believe involve the most complex or subjective decisions or assessments.

Oil and Gas Reserves. The reserve estimates presented herein were made in accordance with oil and gas reserve estimation and disclosure authoritative accounting guidance according to Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") Topic 932, Extractive Activities — Oil and Gas ("FASB ASC 932") as updated in order to align the reserve calculation and disclosure requirements with those in SEC Release No. 33-8995.

The Company utilizes reliable technology such as seismic data and interpretation, wireline formation tests, geophysical logs and core data to assess its resources. However, none of these technologies have contributed to a material addition to the proved reserves in this report.

Estimates of proved crude oil and natural gas reserves require significant professional judgment and materially affect the Company's depreciation, depletion and amortization ("DD&A") expense. For example, if estimates of proved reserves decline, the Company's DD&A rate will increase, resulting in a decrease in net income. A decline in estimates of proved reserves may result from a number of factors including lower prices, evaluation of additional operating history, mechanical problems on our wells and catastrophic events. Lower prices also make it uneconomical to drill wells or produce from fields with high operating costs.

The Company's proved reserves are a function of many assumptions, all of which could deviate materially from actual results. As a result, the estimates of proved reserves could vary over time, and could vary from actual results.

Full Cost Method of Accounting.   The Company uses the full cost method of accounting for exploration and development activities as defined by the SEC Release No. 33-8995, Modernization of Oil and Gas Reporting Requirements (“SEC Release No. 33-8995”) and Financial Accounting Standards Board (“FASB”) Accounting Standards Codification (“ASC”) Topic 932, Extractive Additives — Oil and Gas (“FASB ASC 932”). Under this method of accounting, the costs of unsuccessful, as well as successful, exploration and development activities are capitalized as oil and gas properties. This includes any internal costs that are directly related to exploration and development activities but does not include any costs related to production, general corporate overhead or similar activities. The carrying amount of oil and natural gas properties also includes estimated asset retirement costs recorded on the fair value of the asset retirement obligation when incurred. Gain or loss or other disposition of oil and natural gas properties is not recognized, unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas attributable to a country.

The sum of net capitalized costs and estimated future development costs of oil and natural gas properties are amortized using the units-of-production method based on the Company’s proved reserves. Oil and natural gas reserves and production are converted into equivalent units based on relative energy content. Asset retirement costs are included in the base costs for calculating depletion.

Under the full cost method, costs of unevaluated properties and major development projects expected to require significant future costs may be excluded from capitalized costs being amortized. While the Company does not have any material amounts as described in this paragraph at the current time, it has been a larger consideration in prior years. The Company excludes significant costs until proved reserves are found or until it is determined that the costs are impaired. The Company reviews its unproved leasehold costs quarterly or when management determines that events or circumstances indicate that the recorded carrying value of the unevaluated properties may not be recoverable. The fair values of unproved properties are evaluated utilizing a discounted net cash flows model based on management’s assumptions of future oil and gas production, commodity prices, operating and development costs; as well as appropriate discount rates. The estimated prices used in the cash flow analysis are determined by management based on forward price curves for the related commodities, adjusted for average historical location and quality differentials. Estimates of cash flows related to probable and possible reserves are reduced by additional risk weighting factors. The amount of any impairment is transferred to the capitalized costs being amortized.

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Impairment of Oil and Gas Properties. Companies that use the full cost method of accounting for oil and natural gas exploration and development activities are required to perform a ceiling test calculation each quarter. The full cost ceiling test is an impairment test prescribed by SEC Regulation S-X Rule 4-10. The ceiling test is performed quarterly, on a country-by-country basis, utilizing the average of prices in effect on the first day of the month for the preceding twelve-month period in accordance with SEC Release No. 33-8995. The ceiling limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved crude oil and natural gas reserves discounted at 10%, plus the lower of cost or market value of unproved properties, less any associated tax effects. If such capitalized costs exceed the ceiling, the Company will record a write-down to the extent of such excess as a non-cash charge to earnings. Any such write-down will reduce earnings in the period of occurrence and results in a lower depletion, depreciation and amortization ("DD&A") rate in future periods. A write-down may not be reversed in future periods even though higher oil and natural gas prices may subsequently increase the ceiling.

The Company did not have any write-downs related to the full cost ceiling limitation in 2018, 2017 or 2016.

Deferred Financing Costs. The Company follows ASU No. 2015-03, Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs for its Term Loan Facility, Second Lien Notes, and the Unsecured Notes and includes the costs for issuing debt including issuance discounts as a direct deduction from the carrying amount of the related debt liability.

Additionally, the Company follows ASU No. 2015-15, Interest – Imputation of Interest (Subtopic 835-30): Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line of Credit Arrangements for its Revolving Credit Facility and includes the costs related to the issuance of the Revolving Credit Facility in Other assets on the Consolidated Balance Sheets.

Asset Retirement Obligation. The Company's asset retirement obligations ("ARO") consist primarily of estimated costs of dismantlement, removal, site reclamation and similar activities associated with its oil and natural gas properties. FASB ASC Topic 410, Asset Retirement and Environmental Obligations ("FASB ASC 410") requires that the discounted fair value of a liability for an ARO be recognized in the period in which it is incurred with the associated asset retirement cost capitalized as part of the carrying cost of the oil and natural gas asset. The recognition of an ARO requires that management make numerous estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an ARO, estimated probabilities, amounts and timing of settlements; the credit-adjusted, risk-free rate to be used; inflation rates, and future advances in technology. In periods subsequent to initial measurement of the ARO, the Company must recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Increases in the ARO liability due to passage of time impact net income as accretion expense. The related capitalized costs, including revisions thereto, are charged to expense through DD&A.

Revenue Recognition. The Company generally sells oil and natural gas under both long-term and short-term agreements at prevailing market prices and under multi-year contracts that provide for a fixed price of oil and natural gas. On January 1, 2018, the Company adopted the new accounting standard, ASC 606 Revenue from Contracts with Customers and all related amendments. See Note 2 for additional details and disclosures related to the Company's adoption of this standard.

Valuation of Deferred Tax Assets. The Company uses the asset and liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are determined based on differences between the financial statement carrying values and their respective income tax basis (temporary differences).

To assess the realization of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment.

The Company has recorded a valuation allowance against all of its deferred tax assets as of December 31, 2018. Some or all of this valuation allowance may be reversed in future periods against future income.

Derivative Instruments and Hedging Activities. The Company follows FASB ASC Topic 815, Derivatives and Hedging (“FASB ASC 815”). The Company records the fair value of its commodity derivatives as an asset or liability on the Consolidated Balance Sheets, and records the changes in the fair value of its commodity derivatives in the Consolidated Statements of Operations as an unrealized gain or loss on commodity derivatives.

Fair Value Measurements. The Company follows FASB ASC Topic 820, Fair Value Measurements and Disclosures (“FASB ASC 820”). Under FASB ASC 820, fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at measurement date and establishes a three-level hierarchy for measuring fair value. The valuation assumptions the Company has used to measure the fair value of its commodity derivatives were observable inputs based on market data obtained from independent sources and are considered Level 2 inputs (quoted prices for similar assets, liabilities (adjusted) and market-corroborated inputs). See Note 9 for additional information.

In consideration of counterparty credit risk, the Company assessed the possibility of whether each counterparty to the derivative would default by failing to make contractually required payments as scheduled in the derivative instrument in determining the fair value. Additionally, the Company considers that the counterparty is of substantial credit quality and has the financial resources and willingness to meet its potential repayment obligations associated with the derivative transactions.

Legal, Environmental and Other Contingencies. A provision for legal, environmental and other contingencies is charged to expense when the loss is probable and the cost can be reasonably estimated. Determining when expenses should be recorded for these contingencies and the appropriate amounts for accrual is a complex estimation process that includes the subjective judgment of management. In many cases, management's judgment is based on interpretation of laws and regulations, which can be interpreted differently by regulators and/or courts of law. The Company's management closely monitors known and potential legal, environmental and other contingencies and periodically determines when the Company should record losses for these items based on information available to the Company. Contingent gains arise if the outcome of future events may result in a possible gain or benefit to the Company and are recorded when the gain is realized.

Share-Based Payment Arrangements. The Company follows FASB ASC Topic 718, Compensation — Stock Compensation ("FASB ASC 718") which requires the measurement and recognition of compensation expense for all share-based payment awards made to employees and directors, including employee stock options, based on estimated fair values. Share-based compensation expense recognized under FASB ASC 718 for the years ended December 31, 2018, 2017 and 2016 was $11.8 million, $40.0 million and $5.6 million, respectively. See Note 7 for additional information.

Conversion of Barrels of Oil to Mcfe of Gas. The Company converts barrels of oil and other liquid hydrocarbons to Mcfe at a ratio of one barrel of oil or liquids to six Mcfe. This conversion ratio, which is typically used in the oil and gas industry, represents the approximate energy equivalent of a barrel of oil or other liquids to an Mcf of natural gas. The sales price of one barrel of oil or liquids has been much higher than the sales price of six Mcf of natural gas over the last several years, so a six to one conversion ratio does not represent the economic equivalency of six Mcf of natural gas to a barrel of oil or other liquids.

Recent accounting pronouncements.

Revenues from Contracts with Customers: In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606) and in 2016, the FASB issued ASU 2016-08, Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net), and ASU 2016-10, Revenues from Contracts with Customers (Topic 606): Identifying Performance Obligations and Licensing, which supersede the revenue recognition requirements in Topic 605, Revenue Recognition, and industry-specific guidance in Subtopic 932-605, Extractive Activities - Oil and Gas - Revenue Recognition. The new standard requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods or services.

On January 1, 2018, we adopted the new accounting standard ASC 606, Revenue from Contracts with Customers and all the related amendments (the "new revenue standard") using the modified retrospective method. We recorded a net addition to beginning retained earnings of $1.8 million as of January 1, 2018 due to the cumulative impact of adopting the new revenue standard, with the impact related to changing from the entitlements method to the sales method to account for wellhead imbalances. The impact to revenues for the twelve months ended December 31, 2018 is immaterial to the overall consolidated financial statements as a result of applying the new revenue standard. The comparative information has not been restated and continues to be reported under the accounting standards for those periods. See Note 2 for additional details related to the adoption of this standard. We expect the impact of the adoption of the new revenue standard to be immaterial to our net income on an on-going basis.

Stock Compensation: In May 2017, the FASB issued ASU 2017-09, Compensation-Stock Compensation (Topic 718) ("ASU No. 2017-09"), which is intended to clarify and reduce diversity in practice and cost and complexity when applying the guidance in Topic 718, Compensation-Stock Compensation, to a change to the terms or conditions of a share-based payment award. The Company adopted ASU 2017-09 on January 1, 2018 and the implementation of this ASU did not have a material impact on the Company's consolidated financial statements.

Leases: In February 2016, the FASB established Topic 842, Leases, by issuing issued ASU 2016-02, Leases ("ASU No. 2016-02"), which requires lessees to recognize leases on-balance sheet and disclose key information about leasing arrangements. Topic 842 was subsequently amended by ASU 2018-01, Land Easement Practical Expedient for Transition to Topic 842; ASU No. 2018-10, Codification Improvements to Topic 842, Leases; and ASU No. 2018-11, Targeted Improvements. The new standard establishes a right-of-use ("ROU") model that requires a lessee to recognize a ROU asset and lease liability on the balance sheet for all leases. Leases will be classified as finance or operating, with classification affecting the pattern and classification of expense recognition in the income statement.

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On January 1, 2019, we adopted the new standard. A modified retrospective transition approach is required, applying the new standard to all leases existing at the date of initial application. An entity may choose to use either (1) its effective date or (2) the beginning of the earliest comparative period presented in the financial statements as its date of initial application. If an entity chooses the second option, the transition requirements for existing leases also apply to leases entered into between the date of initial application and the effective date. The entity must also recast its comparative period financial statements and provide the disclosures required by the new standard for the comparative periods. We adopted the new standard on January 1, 2019 and will use the effective date as our date of initial application. Consequently, financial information will not be updated and the disclosures required under the new standard will not be provided for dates and periods before January 1, 2019.

The new standard provides a number of optional practical expedients in transition. We expect to elect the package of practical expedients, which permits us not to reassess under the new standard our prior conclusions about lease identification, lease classification and initial direct costs. We also expect to adopt the practical expedient pertaining to land easements. We do not expect to elect the use-of-hindsight.

The new standard also provides practical expedients for an entity's ongoing accounting. We expect to elect the short-term lease recognition exemption for all leases that qualify. For those leases that qualify, we will not recognize ROU assets or lease liabilities, and this includes not recognizing ROU assets or lease liabilities for existing short-term leases of those assets in transition. We will continue to evaluate the practical expedients related to lease and non-lease components.

We expect that this standard will have a material effect on our financial statements. While we continue to assess all of the effects of adoption, we currently believe the most significant effects relate to (1) the recognition of new ROU assets and lease liabilities on our balance sheet for our office and equipment operating leases; and (2) the requirement to provide significant new disclosures about our leasing activities. These ROU assets and liabilities are not deemed to be debt within the definitions of our debt covenants.

On adoption, we currently expect to recognize additional operating liabilities with corresponding ROU assets of the same amount based on the present value of the remaining minimum rental payments under current leasing standards for existing operating leases.

Derivatives: In August 2017, the FASB issued ASU 2017-12, Derivatives and Hedging (Topic 815) ("ASU No. 2017-12"), which makes significant changes to the current hedge accounting rules. The new guidance impacts the designation of hedging relationships, measurement of hedging relationships, presentation of the effects of hedging relationships, assessment of hedge effectiveness, and disclosures. The guidance is effective for annual periods beginning after December 15, 2018, including interim periods within those annual periods. The Company does not expect the adoption of ASU No. 2017-12 to have a material impact on its consolidated financial statements as the Company does not elect hedge accounting.

Fair Value Measurements. In August 2018, the FASB issued ASU No. 2018-13, Fair Value Measurements (Topic 820): Disclosure Framework — Changes to the Disclosure Requirements for Fair Value Measurement. The amendments in this update modify the disclosure requirements on fair value measurements in Topic 820. The ASU is effective for the public companies for fiscal years beginning after December 15, 2019, and interim periods therein. Early adoption is permitted. The Company is currently assessing the impact of this standard on its consolidated financial statements.

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Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Objectives and Strategy: The Company is exposed to commodity price risk. The following quantitative and qualitative information is provided about financial instruments to which we were a party at December 31, 2018, and from which we may incur future gains or losses from changes in commodity prices. We do not enter into derivative or other financial instruments for speculative or trading purposes.

The Company's major market risk exposure is in the pricing applicable to its natural gas and oil production. Realized pricing is currently driven primarily by the prevailing price for the Company's natural gas production. Historically, prices received for natural gas production have been volatile and unpredictable. Pricing volatility is expected to continue. The prices we receive for our production depend on many factors outside of our control, including volatility in the differences between product prices at sales points and the applicable index price.

The Company relies on various types of derivative instruments to manage its exposure to commodity price risk and to provide a level of certainty in the Company's forward cash flows supporting the Company's capital investment program. These types of instruments may include fixed price swaps, costless collars, or basis differential swaps. These contracts are financial instruments and do not require or allow for physical delivery of the hedged commodity. While mitigating the effects of fluctuating commodity prices, these derivative contracts may limit the benefits we would receive from increases in commodity prices above the fixed hedge prices.

Under the Revolving Credit Facility, the Company is subject to minimum hedging requirements. Through September 29, 2019, the Company is required to hedge a minimum of 65% of the quarterly projected volumes of natural gas from its proved developed producing ("PDP") reserves; and during the period beginning on September 30, 2019 and ending on March 30, 2020, the Company is required to hedge a minimum of 50% of the quarterly projected volumes of natural gas from PDP reserves. Beginning April 1, 2020, the Company will no longer be subject to a minimum hedging requirement.

The Company's hedging policy limits the amounts of resources hedged to not more than 50% of its forecasted production volumes without Board approval. During 2018, the Board approved all commodity derivative hedge contracts for volumes exceeding 50% of forecasted production volumes.

Fair Value of Commodity Derivatives: FASB ASC 815 requires that all derivatives be recognized on the balance sheet as either an asset or liability and be measured at fair value. Changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. The Company does not apply hedge accounting to any of its derivative instruments.

Derivative contracts that do not qualify for hedge accounting treatment are recorded as derivative assets and liabilities at fair value on the balance sheet and the associated unrealized gains and losses are recorded as current expense or income in the income statement. Unrealized gains or losses on commodity derivatives represent the non-cash change in the fair value of these derivative instruments and do not impact operating cash flows on the cash flow statement.

Commodity Derivative Contracts: At December 31, 2018, the Company had the following open commodity derivative contracts to manage commodity price risk. For the fixed price swaps, the Company receives the fixed price for the contract and pays the variable price to the counterparty. For the basis swaps, the Company receives a fixed price for the difference between two sales points for a specified commodity volume over a specified time period. For the collars, the Company pays the counterparty if the market price is above the ceiling price and the counterparty pays the Company if the market price is below the floor price on a notional quantity. The reference prices of these commodity derivative contracts are typically referenced to index prices as published by independent third parties.

Type	Index	Total Volumes (in millions)	Weighted Average Price Per Unit	Fair Value - December 31, 2018 Asset (Liability)
Natural Gas fixed price swaps		(Mmbtu)	($/Mmbtu)	
2019	NYMEX-Henry Hub	185.9	$ 2.81	$ (12,832)
2020	NYMEX-Henry Hub	22.8	$ 2.76	$ (4,506)
Natural Gas basis swaps		(Mmbtu)	($/Mmbtu)	
2019	NW Rockies Basis Swap	105.9	$ 0.67	$ (41,286)
Crude oil fixed price swaps		(Bbl)	($/Bbl)	
2019	NYMEX-WTI	1.4	$ 58.45	$ 15,143
2020	NYMEX-WTI	0.1	$ 60.05	$ 994

Type	Index	Total Volumes (in millions)	Weighted Average Floor Price	Weighted Average Ceiling Price	Fair Value - December 31, 2018 Asset (Liability)
Natural Gas collars			($/MMBTU)		
2020	NYMEX	9.1	$2.75	$ 3.19	$ (346)

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Subsequent to December 31, 2018 and through February 28, 2019, the Company has closed out several oil contracts prior to their scheduled settlement dates and entered into the following commodity derivative contracts to manage commodity price risk.

Type	Remaining Contract Period	Index	Volume/MMBTU/Day	Average Price/MMBTU
Natural gas fixed price swaps				
	Apr. 2019 - Oct. 2019	NYMEX-Henry Hub	40,000	$ 2.90

Type	Remaining Contract Period	Index	Volume/MMBTU/Day	Average Differential/MMBTU
Natural gas basis swaps				
	Apr. 2019 - Oct. 2019	NYMEX-Henry Hub	100,000	$ (0.52)
	Jul. 2019 - Sept. 2019	NYMEX-Henry Hub	50,000	$ (0.34)

Type	Remaining Contract Period	Index	Volume/Bbls/Day	Average Price/Bbls
Crude oil fixed price swaps				
	Apr. 2019 - Dec. 2019	NYMEX-WTI	1,000	$ 56.75
	Apr. 2019 - Jun. 2019	NYMEX-WTI	1,000	$ 57.70

Type	Remaining Contract Period	Index	Volume/MMBTU/Day	Weighted Average Floor Price//MMBTU	Weighted Average Ceiling Price/MMBTU
Natural gas collars					
	Jan. 2020 - Mar. 2020	NYMEX	10,000	$ 2.80	$ 3.30
	Apr. 2020 - Jun. 2020	NYMEX	236,000	$ 2.32	$ 2.83

Type	Remaining Contract Period	Index	Volume/MMBTU/Day	Weighted Average Floor Price/MMBTU	Premium
Natural gas put options					
	Apr. 2020 - Jun. 2020	NYMEX	114,000	$ 2.41	$ (1,287,650)

(1) Represents swap contracts that fix the basis differentials for gas sold at or near Opal, Wyoming and the value of natural gas established on the last trading day of the month by the NYMEX for natural gas swaps for the respective period.

The following table summarizes the pre-tax realized and unrealized gains and losses the Company recognized related to its natural gas derivative instruments in the Consolidated Statements of Operations for the years ended December 31, 2018, 2017 and 2016:

	For the Year Ended December 31,		
Commodity Derivatives (000's):	2018	2017	2016
Realized gain (loss) on commodity derivatives-natural gas (1)	$(77,031)	$11,446	$ —
Realized gain (loss) on commodity derivatives-crude oil(1)	(8,382)	—	—
Unrealized gain (loss) on commodity derivatives (1)	(59,799)	16,966	—
Total gain (loss) on commodity derivatives	$(145,212)	$28,412	$ —

(1) Included in gain (loss) on commodity derivatives in the Consolidated Statements of Operations.

The realized gain or loss on commodity derivatives relates to actual amounts received or paid or to be received or paid under the Company's derivative contracts and the unrealized gain or loss on commodity derivatives represents the change in the fair value of these derivative instruments over the remaining term of the contract.

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Item 8. Financial Statements and Supplementary Data.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of the Company is responsible for the preparation and integrity of all information contained in this Annual Report. The accompanying financial statements have been prepared in conformity with accounting principles generally accepted in the United States of America. The financial statements include amounts that are management's best estimates and judgments.

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). Under the supervision and with the participation of our management, including our chief executive officer and chief financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework). Based on our evaluation under the framework in Internal Control — Integrated Framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2018.

Ernst & Young LLP, the independent registered public accounting firm that audited the accompanying financial statements included in this Annual Report, has issued an attestation report on the effectiveness of our internal control over financial reporting as of December 31, 2018, as stated in their report which is included herein.

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Report of Independent Registered Public Accounting Firm

The Shareholders and Board of Directors of Ultra Petroleum Corp. and subsidiaries

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Ultra Petroleum Corp. and subsidiaries (the Company) as of December 31, 2018 and 2017, the related consolidated statements of operations, shareholders' equity, 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 7, 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 2006.

Denver, Colorado

March 7, 2019

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Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of Ultra Petroleum Corp. and subsidiaries

Opinion on Internal Control over Financial Reporting

We have audited Ultra Petroleum Corp. and subsidiaries' 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, Ultra Petroleum Corp. and subsidiaries (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 statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2018, and the related notes and our report dated March 7, 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 Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

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

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

/s/ Ernst & Young LLP

Denver, Colorado

March 7, 2019

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ULTRA PETROLEUM CORP. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2018	2017
	(Amounts in thousands of U. S. dollars, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$17,014	$16,631
Restricted cash	2,291	1,638
Oil and gas revenue receivable	133,042	86,487
Joint interest billing and other receivables, net	11,348	16,616
Derivative asset	23,374	16,865
Income tax receivable	6,431	10,091
Inventory	18,757	13,450
Other current assets	2,473	5,647
Total current assets	214,730	167,425
Oil and gas properties, net, using the full cost method of accounting:		
Proven	1,497,727	1,325,068
Property, plant and equipment	11,635	9,569
Other	9,196	10,920
Total assets	$1,733,288	$1,512,982
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$36,923	$59,951
Accrued liabilities	58,574	80,268
Production taxes payable	58,365	51,352
Current portion of long-term debt	7,313	—
Interest payable	28,672	24,406
Capital cost accrual	15,014	32,513
Derivative liability	62,350	—
Total current liabilities	267,211	248,490
Long-term debt		
Long-term debt	2,036,722	2,175,000
Add: Premium on exchange transaction	228,096	—
Less: Unamortized deferred financing costs and discount	(56,650)	(58,789)
Total long-term debt, net	2,208,168	2,116,211
Deferred gain on sale of liquids gathering system	94,636	105,189
Other long-term obligations	211,895	197,728
Total liabilities	2,781,910	2,667,618

Commitments and contingencies (Note 12)		
Shareholders' equity:		
Common stock — no par value; authorized — 750,000,000; issued and outstanding shares — 197,383,295 and 196,346,736 at December 31, 2018 and 2017, respectively	2,137,443	2,116,018
Treasury stock	(49)	(49)
Retained loss	(3,186,016)	(3,270,605)
Total shareholders' deficit	(1,048,622)	(1,154,636)
Total liabilities and shareholders' equity	$1,733,288	$1,512,982

Approved on behalf of the Board:

/s/ Brad Johnson	/s/ Michael J. Keeffe
President, Chief Executive Officer and Director	Director

See accompanying notes to consolidated financial statements.

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ULTRA PETROLEUM CORP. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2018	2017	2016
	(Amounts in thousands of U.S. dollars, except per share data)		
Revenues:			
Natural gas sales	$722,313	$748,682	$609,756
Oil sales	153,534	133,368	111,335
Other revenues	16,652	9,823	—
Total operating revenues	892,499	891,873	721,091
Expenses:			
Lease operating expenses	90,290	92,326	89,134
Facility lease expense	25,947	21,749	20,686
Production taxes	93,322	91,067	69,737
Gathering fees	89,806	86,953	86,809
Transportation charges	—	—	20,049
Depletion, depreciation and amortization	204,255	161,945	125,121
General and administrative	25,005	39,548	9,179
Other expenses	9,118	—	—
Total operating expenses	537,743	493,588	420,715
Operating income	354,756	398,285	300,376
Other (expense) income, net:			
Interest expense (excludes contractual interest expense of $141.5 million for the year ended December 31, 2016)	(148,316)	(361,367)	(66,565)
Gain (loss) on commodity derivatives	(145,212)	28,412	—
Deferred gain on sale of liquids gathering system	10,553	10,553	10,553
Restructuring expenses	—	—	(7,176)
Contract settlement income (expense), net	12,656	(52,707)	(131,106)
Other income (expense), net	1,212	(237)	(3,082)
Total other (expense) income, net	(269,107)	(375,346)	(197,376)
Reorganization items, net	—	140,907	(47,503)
Income before income tax expense (benefit)	85,649	163,846	55,497
Income tax expense (benefit)	442	(13,294)	(654)
Net income	$85,207	$177,140	$56,151
Basic Earnings per Share:			
Net income per common share — basic	$0.43	$1.08	$0.70
Fully Diluted Earnings per Share:			

Net income per common share — fully diluted	$0.43	$1.08	$0.70
Weighted average common shares outstanding — basic	196,964	163,824	79,996
Weighted average common shares outstanding — fully diluted	197,541	163,976	80,363

See accompanying notes to consolidated financial statements.

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ULTRA PETROLEUM CORP. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

(Amounts in thousands of U.S. dollars, except share data)

	Shares Issued and Outstanding	Common Stock	Retained Loss	Treasury Stock	Total Shareholders' (Deficit) Equity
Balances at December 31, 2015	79,933	$502,050	$(3,493,811)	$(176)	$(2,991,937)
Employee stock plan grants	145	—	—	—	—
Shares re-issued from treasury	—	—	(127)	127	—
Net share settlements	(61)	—	(378)	—	(378)
Fair value of employee stock plan grants	—	8,013	—	—	8,013
Net income	—	—	56,151	—	56,151
Balances at December 31, 2016	80,017	$510,063	$(3,438,165)	$(49)	$(2,928,151)
Equitization of Holdco Notes	70,579	978,230	—	—	978,230
Rights Offering, including Backstop	44,390	573,774	—	—	573,774
Employee stock plan grants	10	—	—	—	—
Stock plan grants	2,191	26,673	—	—	26,673
Net share settlements	(840)	—	(9,580)	—	(9,580)
Fair value of employee stock plan grants	—	27,278	—	—	27,278
Net income	—	—	177,140	—	177,140
Balances at December 31, 2017	196,347	$2,116,018	$(3,270,605)	$(49)	$(1,154,636)
Employee stock plan grants	1,770	—	—	—	—
Net share settlements	(734)	—	(2,379)	—	(2,379)
Issuance of warrants	—	5,786	—	—	5,786
Fair value of employee stock plan grants	—	15,639	—	—	15,639
Initial adoption of ASC 606	—	—	1,761	—	1,761
Net income	—	—	85,207	—	85,207
Balances at December 31, 2018	197,383	$2,137,443	$(3,186,016)	$(49)	$(1,048,622)

See accompanying notes to consolidated financial statements.

Shareholders' Equity Explanatory Note:

In conjunction with emergence from chapter 11 proceedings in April 2017, the Company issued new common shares of the Company (the "New Equity") to holders of existing pre-petition common shares of the Company (the "Existing

Common Shares”) at a conversion ratio of 0.521562. As a result, the share counts have been adjusted to reflect this conversion as if it had occurred as of the earliest period presented.

Consistent with the Plan, 194,991,656 shares of New Equity were issued as follows:

- 70,579,367 shares of New Equity were issued pro rata to holders of the Company’s prepetition senior notes with claims allowed under the Debtors’ Second Amended Joint Chapter 11 Plan of Reorganization;
- 80,022,410 shares of New Equity were issued pro rata to holders of Existing Common Shares;
- 2,512,623 shares of New Equity were issued to commitment parties under the backstop commitment agreement in respect of the commitment premium due thereunder;
- 18,844,363 shares of New Equity were issued to commitment parties under the backstop commitment agreement in connection with their backstop obligation thereunder; and
- 23,032,893 shares of New Equity were issued to participants in the rights offering completed pursuant to the Plan.

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ULTRA PETROLEUM CORP. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2018	2017	2016
	(Amounts in thousands of U.S. dollars)		
Cash provided by (used in):			
Operating activities:			
Net income for the period	$85,207	$177,140	$56,151
Adjustments to reconcile net income to cash provided by operating activities:			
Depletion, depreciation and amortization	204,255	161,945	125,121
Unrealized (gain) loss on commodity derivatives	59,799	(16,966)	—
Deferred gain on sale of liquids gathering system	(10,553)	(10,553)	(10,553)
Stock compensation	11,825	39,977	5,562
Non-cash reorganization items, net	—	(453,909)	42,523
Amortization of premium on restructuring	(1,083)	—	—
Amortization of deferred financing costs	11,210	7,483	4,194
Other	3,501	(1,047)	2,676
Net changes in operating assets and liabilities:			
Accounts receivable	(46,276)	(14,483)	(19,635)
Other current and non-current assets	5,630	14,615	(16,186)
Accounts payable	(13,206)	34,349	(63,924)
Accrued liabilities	(20,294)	89,935	133,144
Production taxes payable	7,098	7,023	(7,944)
Interest payable	4,266	36,220	57,117
Other long-term obligations	2,674	4,737	276
Current taxes payable/receivable	6,844	(11,198)	2,548
Net cash provided by operating activities	310,897	65,268	311,070
Investing Activities:			
Oil and gas property expenditures	(426,166)	(557,029)	(269,314)
Sale of oil and gas properties	61,304	114,263	—
Change in capital cost accrual and accounts payable	(27,322)	20,076	(8,134)
Inventory	(5,335)	(8,916)	(1,123)
Proceeds from sale of property, plant and equipment	2,872	—	—
Purchase of property, plant and equipment	(7,063)	(3,705)	(329)
Net cash used in investing activities	(401,710)	(435,311)	(278,900)
Financing activities:			
Borrowings under Credit Agreement	1,020,000	773,000	369,000
Payments under Credit Agreement	(916,000)	(773,000)	—
Borrowings under Term Loan	—	975,000	—
Extinguishment of long-term debt (chapter 11)	—	(2,459,000)	—
Proceeds from issuance of Senior Notes	—	1,200,000	—
Deferred financing costs	(9,773)	(73,092)	—

Shares issued, net of transaction costs	—	573,774	—
Repurchased shares/net share settlements	(2,378)	(9,581)	(379)
Debt extinguishment costs	—	(223,838)	—
Net cash provided by (used in) financing activities	91,849	(16,737)	368,621
(Decrease)/Increase in cash during the period	1,036	(386,780)	400,791
Cash, cash equivalents, and restricted cash at beginning of period	18,269	405,049	4,258
Cash, cash equivalents, and restricted cash end of period	$19,305	$18,269	$405,049
Supplemental cash flow disclosures			
Cash paid for:			
Interest	$135,230	$317,120	$4,793
Income taxes	$—	$—	$94
Supplemental non-cash investing and financing activities			
Premium on Exchange Transaction	$229,179	$—	$—
Principal reduction from exchange transaction	$(229,179)	$—	$—

See accompanying notes to consolidated financial statements.

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ULTRA PETROLEUM CORP. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(All amounts in this Report on Form 10-K are expressed in thousands of U.S. dollars (except per share data), unless otherwise noted).

DESCRIPTION OF THE BUSINESS:

Ultra Petroleum Corp. and its wholly-owned subsidiaries (collectively the “Company”, “Ultra”, “our”, “we”, or “us”)is an independent oil and gas company engaged in the development, production, operation, exploration and acquisition of oil and natural gas properties. The Company is incorporated under the laws of Yukon, Canada. The Company’s principal business activities are developing its long-life natural gas reserves in the Pinedale and Jonah fields of the Green River Basin of Wyoming.

2018 Debt Exchange

In December 2018, the Company exchanged (i) $505 million aggregate principal amount, or 72.1%, of the 6.875% Senior Notes due 2022 (the “2022 Notes”) and (ii) $275 million aggregate principal amount, or 55.0%, of the 7.125% Senior Notes due 2025 (the “2025 Notes” and, together with the 2022 Notes, the “Unsecured Notes”) of Ultra Resources, Inc., a Delaware corporation (“Ultra Resources”), a wholly owned subsidiary of the Company, for (a) $545.0 million aggregate principal amount of new 9.00% Cash/2.00% PIK Senior Secured Second Lien Notes due July 2024 of Ultra Resources (the “Second Lien Notes”), and (b) an aggregate of 10,919,499 new $0.01 warrants of the Company entitling the holder thereof to purchase one common share of the Company (each a “Warrant” and collectively, the “Warrants”) (such transaction, the “Exchange Transaction”). The Exchange Transaction reduced indebtedness by approximately $235 million. Refer to Note 6 for additional details and the accounting treatment on the Exchange Transaction.

1. SIGNIFICANT ACCOUNTING POLICIES:

Basis of presentation and principles of consolidation: The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries. The Company presents its financial statements in accordance with U.S. Generally Accepted Accounting Principles (“GAAP”). All inter-company transactions and balances have been eliminated.

Cash and Cash Equivalents: The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents.

Restricted Cash: Restricted cash represents cash received by the Company from production sold where the final division of ownership of the production is unknown or in dispute.

The Company adopted Accounting Standards Update (“ASU”) 2016-18, Statement of Cash Flows (Topic 230): Restricted Cash and reports the change in cash, cash equivalents, and restricted cash in total on the Consolidated Statement of Cash Flows as of December 31, 2017. The Consolidated Statement of Cash Flows as of December 31, 2016 has been adjusted to conform to the new standard. See the following table for a reconciliation of cash, cash equivalents, and restricted cash reported within the Consolidated Financial Statements:

Current Presentation	December 31, 2018	December 31, 2017	December 31, 2016
Cash and Cash Equivalents	$ 17,014	$ 16,631	$ 401,478
Restricted Cash	2,291	1,638	3,571

Total cash, cash equivalents, and restricted cash	$ 19,305	$ 18,269	$ 405,049

Accounts Receivable: Accounts receivable are stated at the historical carrying amount net of write-offs and an allowance for uncollectible accounts. Included in the Other expenses on the Consolidated Statements of Operations is the provision for uncollectible accounts of $4.9 million. The carrying amount of the Company's accounts receivable approximates fair value because of the short-term nature of the instruments. The Company routinely assesses the collectability of all material trade and other receivables.

Property, Plant and Equipment: Capital assets are recorded at cost and depreciated using the declining-balance method based on their respective useful life.

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Oil and Natural Gas Properties: The Company uses the full cost method of accounting for exploration and development activities as defined by the Securities and Exchange Commission ("SEC") Release No. 33-8995, Modernization of Oil and Gas Reporting Requirements ("SEC Release No. 33-8995") and Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") Topic 932, Extractive Activities – Oil and Gas ("FASB ASC 932"). Under this method of accounting, the costs of successful, as well as unsuccessful, exploration and development activities are capitalized as oil and gas properties. This includes any internal costs that are directly related to exploration and development activities but does not include any costs related to production, general corporate overhead or similar activities. Interest is capitalized on the cost of unevaluated gas and oil properties that are excluded from amortization and actively being evaluated, if any. The carrying amount of oil and natural gas properties also includes estimated asset retirement costs recorded based on the fair value of the asset retirement obligation when incurred. Gain or loss on the sale or other disposition of oil and natural gas properties is not recognized, unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas attributable to a country.

The sum of net capitalized costs and estimated future development costs of oil and natural gas properties are amortized using the units-of-production method based on the Company's proved reserves. Oil and natural gas reserves and production are converted into equivalent units based on relative energy content. Asset retirement costs are included in the base costs for calculating depletion.

Under the full cost method, costs of unevaluated properties and major development projects expected to require significant future costs may be excluded from capitalized costs being amortized. While the Company does not have any material amounts as described in this paragraph at the current time, it has been a larger consideration in prior years. The Company excludes significant costs until proved reserves are found or until it is determined that the costs are impaired. The Company reviews its unproved leasehold costs quarterly or when management determines that events or circumstances indicate that the recorded carrying value of the unevaluated properties may not be recoverable. The fair values of unproved properties are evaluated utilizing a discounted net cash flows model based on management's assumptions of future oil and gas production, commodity prices, operating and development costs; as well as appropriate discount rates. The estimated prices used in the cash flow analysis are determined by management based on forward price curves for the related commodities, adjusted for average historical location and quality differentials. Estimates of cash flows related to probable and possible reserves are reduced by additional risk-weighting factors. The amount of any impairment is transferred to the capitalized costs being amortized.

Companies that use the full cost method of accounting for oil and natural gas exploration and development activities are required to perform a ceiling test calculation each quarter. The full cost ceiling test is an impairment test prescribed by SEC Regulation S-X Rule 4-10. The ceiling test is performed quarterly, on a country-by-country basis, utilizing the average of prices in effect on the first day of the month for the preceding twelve-month period in accordance with SEC Release No. 33-8995. The ceiling limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved crude oil and natural gas reserves discounted at 10%, plus the lower of cost or market value of unproved properties, less any associated tax effects. If such capitalized costs exceed the ceiling, the Company will record a write-down to the extent of such excess as a non-cash charge to earnings. Any such write-down will reduce earnings in the period of occurrence and results in a lower depletion, depreciation and amortization ("DD&A") rate in future periods. A write-down may not be reversed in future periods even though higher oil and natural gas prices may subsequently increase the ceiling.

The Company did not have any write-downs related to the full cost ceiling limitation in 2018, 2017 or 2016.

Inventories: Inventory includes $17.6 million in pipe and production equipment and miscellaneous materials and supplies that will be utilized during the 2019 drilling program, as well as $1.1 million in crude oil inventory. Our inventories are valued at the lower of cost or net realizable value, with cost determined using either the weighted-average cost, including the cost of transportation and storage, and with net realizable value defined as the estimated selling price in the ordinary course of business, less reasonably predictable costs of transportation. Selling expenses and general and administrative expenses are reported as period costs and excluded from inventory cost.

Derivative Instruments and Hedging Activities: The Company follows FASB ASC Topic 815, Derivatives and Hedging ("FASB ASC 815"). The Company records the fair value of its commodity derivatives as an asset or liability in the Consolidated Balance Sheets, and records the changes in the fair value of its commodity derivatives in the Consolidated Statements of Operations. The Company does not offset the value of its derivative arrangements with the same counterparty. (See Note 8).

Deferred Financing Costs: The Company follows ASU No. 2015-03, Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs for its Term Loan Facility, Second Lien Notes, and the Unsecured Notes and includes the costs for issuing debt including issuance discounts, as a direct deduction from the carrying amount of the related debt liability.

Additionally, the Company follows ASU No. 2015-15, Interest – Imputation of Interest (Subtopic 835-30): Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line of Credit Arrangements for its Revolving Credit Facility and includes the costs related to the issuance of the Revolving Credit Facility in Other assets on the Consolidated Balance Sheets.

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Income Taxes: Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis and operating loss and tax credit carryforwards. 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 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. Valuation allowances are recorded related to deferred tax assets based on the “more likely than not” criteria described in FASB ASC Topic 740, Income Taxes. In addition, the Company recognizes 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.

Warrants: On December 21, 2018, in connection with the consummation of the Exchange Transaction, the Company issued 10,919,499 new Warrants. The Warrants are initially exercisable for one common share of the Company, no par value, at an initial exercise price of $0.01 per Warrant (the “Warrant Exercise Price”). No Warrants will be exercisable until the date on which the volume-weighted average price of the Common Shares is at least $2.50 per Common Share for 30 consecutive trading days (the “Trading Price Condition”). Subject to the Trading Price Condition, the Warrants are exercisable at the option of the holders thereof from the December 21, 2018 until July 14, 2025, at which time all unexercised Warrants will expire and the rights of the holders of such Warrants to purchase Common Shares will terminate. Under the guidance in FASB ASC 815, the Warrants do not meet the definition of a derivative. The Warrants are classified as equity and recorded at fair value as of the date of issuance on the Company’s Consolidated Balance Sheets and no further adjustments to their valuation are made.

Earnings Per Share: Basic earnings per share is computed by dividing net earnings (attributable to common stockholders by the weighted average number of common shares outstanding during each period. Diluted earnings per share is computed by adjusting the average number of common shares outstanding for the dilutive effect, if any, of common stock equivalents. The Company uses the treasury stock method to determine the dilutive effect.

In conjunction with our emergence from chapter 11 proceedings, on April 12, 2017, the Company issued shares of New Equity to holders of Existing Common Shares at a conversion ratio of 0.521562. As a result, the basic and fully diluted share counts have been presented to reflect this conversion as if it had occurred as of the earliest period presented.

Certain share-based payments subject to performance or market conditions are considered contingently issuable shares for purposes of calculating diluted earnings per share. Thus, they are not included in the diluted earnings per share denominator until the performance or market criteria are met. Additionally, the Warrants issued in connection with the Exchange Transaction are not included in the diluted earnings per share denominator using the treasury stock method as the Trading Price Condition on the Warrants exceeded the average market price. For the years ended December 31, 2018 and 2017, the Company had 14.2 million and 3.9 million, respectively, of contingently issuable shares that are not included in the diluted earnings per share denominator. There were no contingently issuable shares outstanding for the year ended December 31, 2016.

The following table provides a reconciliation of components of basic and diluted net income per common share:

	December 31,		
	2018	2017	2016
Net income	$85,207	$177,140	$56,151
Weighted average common shares outstanding during the period	196,964	163,824	79,996
Effect of dilutive instruments	577	152	367
Weighted average common shares outstanding during the period including the effects of dilutive instruments	197,541	163,976	80,363
Net income per common share — basic	$0.43	$1.08	$0.70
Net income per common share — fully diluted	$0.43	$1.08	$0.70
Number of shares not included in dilutive earnings per share that would have been anti-dilutive because the exercise price was greater than the average market price of the common shares	—	—	749

Use of Estimates: Preparation of consolidated financial statements in accordance with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Accounting for Share-Based Compensation: The Company measures and recognizes compensation expense for all share-based payment awards made to employees and directors, including employee stock options, based on estimated fair values in accordance with FASB ASC Topic 718, Compensation – Stock Compensation.

Fair Value Accounting: The Company follows FASB ASC Topic 820, Fair Value Measurements and Disclosures ("FASB ASC 820"), which defines fair value, establishes a framework for measuring fair value under GAAP, and expands disclosures about fair value measurements. This statement applies under other accounting topics that require or permit fair value measurements. See Note 9 for additional information.

Asset Retirement Obligation: The initial estimated retirement obligation of properties is recognized as a liability with an associated increase in oil and gas properties for the asset retirement cost. Accretion expense is recognized over the estimated productive life of the related assets. If the fair value of the estimated asset retirement obligation changes, an adjustment is recorded to both the asset retirement obligation and the asset retirement cost. Revisions in estimated liabilities can result from revisions of estimated inflation rates, changes in service and equipment costs and changes in the estimated timing of settling asset retirement obligations. As a full cost company, settlements for asset retirement obligations for abandonment are adjusted to the full cost pool. The asset retirement obligation is included within other long-term obligations in the accompanying Consolidated Balance Sheets.

Revenue Recognition: The Company generally sells oil and natural gas under both long-term and short-term agreements at prevailing market prices. On January 1, 2018, the Company adopted the new accounting standard, ASC 606, Revenue from Contracts with Customers and all related amendments. See Note 2 for additional details and disclosures related to the Company's adoption of this standard.

Other revenues: Other revenues are comprised of fees paid to us by operators of the gas processing plants where our gas is processed in exchange for the liquids removed from our production.

Capital Cost Accrual: The Company accrues for exploration and development costs in the period incurred, while payment may occur in a subsequent period.

Reclassifications: Certain amounts in the financial statements of prior periods have been reclassified to conform to the current period financial statement presentation. These reclassifications had no effect on the reported results of operations.

Recent Accounting Pronouncements: Revenues from Contracts with Customers: In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606) and in 2016, the FASB issued ASU 2016-08, Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net), and ASU 2016-10, Revenues from Contracts with Customers (Topic 606): Identifying Performance Obligations and Licensing, which supersede the revenue recognition requirements in Topic 605, Revenue Recognition, and industry-specific guidance in Subtopic 932-605, Extractive Activities - Oil and Gas - Revenue Recognition. The new standard requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods or services.

On January 1, 2018, we adopted the new accounting standard ASC 606, Revenue from Contracts with Customers and all the related amendments (the "new revenue standard") using the modified retrospective method. We recorded a net addition to beginning retained earnings of $1.8 million as of January 1, 2018 due to the cumulative impact of adopting the new revenue standard, with the impact related to changing from the entitlements method to the sales method to account for wellhead imbalances. The comparative information has not been restated and continues to be reported under the accounting standards for those periods. See Note 2 for additional details related to the adoption of this standard.

Stock Compensation: In May 2017, the FASB issued ASU 2017-09, Compensation-Stock Compensation (Topic 718) ("ASU No. 2017-09"), which is intended to clarify and reduce diversity in practice and cost and complexity when applying the guidance in Topic 718, Compensation-Stock Compensation, to a change to the terms or conditions of a share-based payment award. The Company adopted ASU 2017-09 on January 1, 2018 and the implementation of this ASU did not have a material impact on the Company's consolidated financial statements.

Leases: In February 2016, the FASB established Topic 842, Leases, by issuing issued ASU 2016-02, Leases ("ASU No. 2016-02"), which requires lessees to recognize leases on-balance sheet and disclose key information about leasing arrangements. Topic 842 was subsequently amended by ASU 2018-01, Land Easement Practical Expedient for Transition to Topic 842; ASU No. 2018-10, Codification Improvements to Topic 842, Leases; and ASU No. 2018-11, Targeted Improvements. The new standard establishes a right-of-use ("ROU") model that requires a lessee to recognize a ROU asset and lease liability on the balance sheet for all leases. Leases will be classified as finance or operating, with classification affecting the pattern and classification of expense recognition in the income statement.

On January 1, 2019, we adopted the new standard. A modified retrospective transition approach is required, applying the new standard to all leases existing at the date of initial application. An entity may choose to use either (1) its effective date or (2) the beginning of the earliest comparative period presented in the financial statements as its date of initial application. If an entity chooses the second option, the transition requirements for existing leases also apply to leases entered into between the date of initial application and the effective date. The entity must also recast its comparative period financial statements and provide the disclosures required by the new standard for the comparative periods. We adopted the new standard on January 1, 2019 and will use the effective date as our date of initial application. Consequently, financial information will not be updated and the disclosures required under the new standard will not be provided for dates and periods before January 1, 2019.

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The new standard provides a number of optional practical expedients in transition. We expect to elect the ‘package of practical expedients’, which permits us not to reassess under the new standard our prior conclusions about lease identification, lease classification and initial direct costs. We also expect to adopt the practical expedient pertaining to land easements. We do not expect to elect the use-of-hindsight.

The new standard also provides practical expedients for an entity’s ongoing accounting. We expect to elect the short-term lease recognition exemption for all leases that qualify. For those leases that qualify, we will not recognize ROU assets or lease liabilities, and this includes not recognizing ROU assets or lease liabilities for existing short-term leases of those assets in transition. We will continue to evaluate the practical expedients related to lease and non-lease components.

We expect that this standard will have a material effect on our financial statements. While we continue to assess all of the effects of adoption, we currently believe the most significant effects relate to (1) the recognition of new ROU assets and lease liabilities on our balance sheet for our office and equipment operating leases; and (2) the requirement to provide significant new disclosures about our leasing activities. These ROU assets and liabilities are not deemed to be debt within the definitions of our debt covenants.

On adoption, we currently expect to recognize additional operating liabilities, with corresponding ROU assets of the same amount based on the present value of the remaining minimum rental payments under current leasing standards for existing operating leases.

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Derivatives: In August 2017, the FASB issued ASU 2017-12, Derivatives and Hedging (Topic 815) (“ASU No. 2017-12”), which makes significant changes to the current hedge accounting rules. The new guidance impacts the designation of hedging relationships; measurement of hedging relationships; presentation of the effects of hedging relationships; assessment of hedge effectiveness; and disclosures. The guidance is effective for annual periods beginning after December 15, 2018, including interim periods within those annual periods. The Company does not expect the adoption of ASU No. 2017-12 to have a material impact on its consolidated financial statements as the Company does not elect hedge accounting.

Fair Value Measurements. In August 2018, the FASB issued ASU No. 2018-13, Fair Value Measurements (Topic 820): Disclosure Framework — Changes to the Disclosure Requirements for Fair Value Measurement. The amendments in this update modify the disclosure requirements on fair value measurements in Topic 820. The ASU is effective for the public companies for fiscal years beginning after December 15, 2019, and interim periods therein. Early adoption is permitted. The Company is currently assessing the impact of this standard on its consolidated financial statements.

2. IMPACT OF ASC 606 ADOPTION – REVENUE RECOGNITION

In accordance with the new revenue standard requirements, the disclosure of the impact of adoption on our consolidated income statement for twelve months ended December 31, 2018 is as follows:

	For the Twelve Months Ended December 31, 2018		
	Under ASC 606	Under ASC 605	Increase/ (Decrease)
	(Amounts in 000's)		
Revenues:			
Natural gas sales	$722,313	$722,365	$ (52)
Oil sales	153,534	153,534	—
Other revenues	16,652	16,652	—
Costs and expenses:			
Production taxes	$93,322	$93,326	$ (4)
Gathering fees	89,806	89,812	(6)
Net income:	$85,207	$85,249	$ (42)

The change to sales of natural gas is due to the change from using the entitlements method for production imbalances to the sales method. The Company evaluated the contracts for sales of oil and natural gas utilizing the principal versus agent indicators, noting no change in revenue recognition resulted from the analysis.

Revenue Recognition

Revenue from Contracts with Customers

Sales of oil and natural gas are recognized at the point control of the product is transferred to the customer, collectability is reasonably assured, and the performance obligations are satisfied. Virtually all of our contracts' pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of the oil or natural gas, and prevailing supply and demand conditions. As a result, the price of the oil and natural gas fluctuates to remain competitive with other available oil and natural gas supplies.

Natural gas sales

We sell natural gas production at the tailgate of the processing plant or at a delivery point downstream, as specified in the contracts with our customers. The production is sold at set volumes and we collect (i) an agreed upon index price, (ii) a specific index price adjusted for pricing differentials, or (iii) a set price. We recognize revenue when control transfers to the purchaser at the tailgate of the processing plant or at the agreed-upon delivery point at the net price received. For these contracts, we have concluded that the Company is the principal for our net revenue interest share of the volumes being sold. Gathering fees are incurred prior to the customer taking control of the product, are not considered to be promised services, and are not included in the transaction price; thus, they are presented as expenses in the Consolidated Statement of Operations.

Our working interest partners are considered the principal for their working interest shares. They have the option to take in kind their volumes, provided they are in compliance with the terms of the joint operating agreements. The Company may act as an agent and market the other partners' share of the natural gas production. If it does so, the Company is considered the agent and revenue continues to be recorded at the Company's net revenue interest in the production, and the portion related to partners' interest is not recognized as revenue.

Oil sales

We sell oil production at (a) the lease automatic custody transfer ("LACT") meter for Wyoming condensate, (b) the tank battery for Utah wax/condensate, or (c) a delivery point downstream, as specified in the contracts with our customers. The production is sold at set volumes and we collect (i) an agreed upon index price, net of pricing differentials or (ii) a set price. We recognize revenue at the point when the customer takes control of the product. For these contracts, we have concluded that the Company is the principal for its net revenue interest share of the volumes being sold. Gathering fees are performed prior to the customer taking control of the product, are not considered to be promised services, and are not included in the transaction price; thus, they are presented as expenses in the Condensed Consolidated Statement of Operations. In conjunction with the adoption of ASC 606, for the twelve months ended December 31, 2018, there was no change to the method used to recognize oil sales and there was no impact to the consolidated financial statements for oil sales.

Our working interest partners are considered the principal for their working interest shares. They have the option to take in kind their volumes. The Company may act as an agent and market the other partners' share of the oil production. If it does so, the Company is considered the agent and revenue is recorded at the Company's net revenue interest in the production.

Other revenues

Our other revenue is comprised of fees paid to us by the operators of the gas processing plants where our gas is processed. Control is transferred upon completion of the processing service. The Company is considered the principal, and revenue is recognized at the point in time that the control is transferred. In conjunction with the adoption of ASC 606, for the twelve months ended December 31, 2018, there was no change to the method used to recognize other processing revenues and there was no impact to the consolidated financial statements for other revenues.

Production imbalances

Previously, the Company elected to utilize the entitlements method to account for natural gas imbalances, which is no longer allowed under ASC 606. In conjunction with the adoption of ASC 606, for the twelve months ended December 31, 2018, there was no material impact to the consolidated financial statements due to this change in accounting for our production imbalances.

Transaction price allocated to remaining performance obligations

A significant number of our product sales are short-term in nature with a contract term of one year or less. For those contracts, we have utilized the practical expedient in ASC 606-10-50-14 exempting the Company from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

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

Contract balances

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

Prior-period performance obligations

We record revenue in the month production is delivered to the purchaser. However, settlement statements for certain natural gas may not be received for 30 to 90 days after the date production is delivered, and as a result, we are required to estimate the amount of production delivered to the purchaser and the price that will be received for the sale of the product. We record the differences between our estimates and the actual amounts received for product sales in the month that payment is received from the purchaser. We have existing internal controls for our revenue estimation process and related accruals, and any identified differences between our revenue estimates and actual revenue received historically have not been significant. For the twelve months ended December 31, 2018, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

3. ASSET RETIREMENT OBLIGATIONS:

The Company is required to record the fair value of an asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development and/or normal use of the assets. The following table summarizes the activities for the Company’s asset retirement obligations for the years ended:

	December 31,	
	2018	2017
Asset retirement obligations at beginning of period	$173,100	$157,173
Accretion expense	12,342	11,689
Liabilities incurred	3,558	8,174
Liabilities divested (1) (2)	(9,372)	(4,812)
Liabilities acquired	-	1,456
Liabilities settled	(70)	(598)
Revisions of estimated liabilities	(96)	18
Asset retirement obligations at end of period	179,462	173,100
Less: current asset retirement obligations	(193)	(263)
Long-term asset retirement obligations (3)	$179,269	$172,837

(1) During the year ended December 31, 2018, the Company divested certain non-core properties in Utah.

(2) During the year ended December 31, 2017, the Company divested certain non-core properties in north-central Pennsylvania.

(3) Included in Other long-term obligations in the Consolidated Balance Sheet.

4. OIL AND GAS PROPERTIES:

	December 31, 2018	2017
Proven Properties:		
Acquisition, equipment, exploration, drilling and environmental costs	$11,577,281	$11,215,563
Less: Accumulated depletion, depreciation and amortization	(10,079,554)	(9,890,495)
Total Oil and gas properties, net	1,497,727	1,325,068

On a unit basis, DD&A was $0.74, $0.59 and $0.44 per Mcfe for the years ended December 31, 2018, 2017 and 2016, respectively.

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5. PROPERTY, PLANT AND EQUIPMENT:

	December 31, 2018			2017
	Cost	Accumulated Depreciation	Net Book Value	Net Book Value
Computer equipment	2,828	(2,209)	619	554
Office equipment	265	(200)	65	95
Leasehold improvements	264	(178)	86	120
Land	2,437	—	2,437	4,637
Production and other equipment	20,232	(11,804)	8,428	4,163
Property, plant and equipment, net	$26,026	$ (14,391)	$11,635	$9,569

6. LONG TERM DEBT:

	December 31, 2018			
	Principal	Unamortized Deferred Financing Costs and Discounts (1)	Unamortized Premium on Exchange Transaction	Carrying Value
Credit Agreement	$104,000	$ —	$ —	$104,000
Term Loan, secured, due 2024	975,000	(26,874)	—	948,126
Second Lien Notes, secured, due 2024	545,000	—	228,096	773,096
6.875% Unsecured Notes due 2022	195,035	(15,168)	—	179,867
7.125% Unsecured Notes due 2025	225,000	(14,608)	—	210,392
	$2,044,035	$ (56,650)	$ 228,096	$2,215,481
Less: Current maturities	7,313	—	—	7,313
Total Long-term debt	$2,036,722	$ (56,650)	$ 228,096	$2,208,168

	December 31, 2017		
	Principal	Unamortized Deferred Financing Costs and Discounts (1)	Carrying Value
Credit Agreement	$—	$ —	$—

Term Loan, secured, due 2024	975,000	(23,357)	951,643
6.875% Unsecured Notes due 2022	700,000	(19,084)	680,916
7.125% Unsecured Notes due 2025	500,000	(16,348)	483,652
	$2,175,000	$ (58,789)	$2,116,211
Less: Current maturities	—	—	—
Total Long-term debt	$2,175,000	$ (58,789)	$2,116,211

(1) Deferred financing costs related to the Revolving Credit Facility are reported within Other assets on the consolidated balance sheet, rather than as a reduction of the carrying amount of long-term debt.

Aggregate maturities of debt at December 31,	
2019	$7,313
2020	$9,750
2021	$9,750
2022	$308,785
2023	$9,750
Beyond 5 years	$1,698,687
Total	$2,044,035

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Ultra Resources, Inc.

Credit Agreement. On April 12, 2017, Ultra Resources, as the borrower, entered into a Credit Agreement (the “Credit Agreement”) with the Company and UP Energy Corporation, as parent guarantors, with Bank of Montreal, as administrative agent (the “RBL Administrative Agent”), and with the other lenders party thereto (collectively, the “RBL Lenders”) from time to time, providing for a revolving credit facility (the “Revolving Credit Facility”) subject to a borrowing base redetermination, which limits the aggregate amount of first lien debt under the Revolving Credit Facility and Term Loan Agreement (as defined below). In September 2018, the borrowing base was reduced from $1.4 million to $1.3 billion in connection with the semi-annual determination, with $975.0 million allocated to the Company’s Term Loan Facility (as defined below) and $325.0 million allocated to the Revolving Credit Facility.

On December 21, 2018, in connection with the consummation of the Exchange Transaction, Ultra Resources and the parent guarantors entered into the Third Amendment to the Credit Agreement (the “Third Amendment”) with the RBL Administrative Agent and the RBL Lenders party thereto. Pursuant to the Third Amendment, the parties agreed, among other things, to amend the Credit Agreement to permit the issuance of the Second Lien Notes and the Exchange Transaction and to revise certain covenants and other provisions of the Credit Agreement, including, but not limited to:

- increasing collateral coverage from 85% to 95% of total PV-9 of Proven Reserves (as defined in the Credit Agreement);
- removing the ability to create, invest in and utilize unrestricted subsidiaries that are not guarantors under the Revolving Credit Facility;
- further limiting the Company’s ability to incur unsecured debt, repay junior debt, and make restricted payments and investments as more thoroughly described in the Third Amendment; and
- providing the ability for the Company to exchange unsecured borrowings to third lien debt within a construct as described in the Third Amendment.

In conjunction with the Exchange Transaction, the Third Amendment was evaluated under FASB ASC 470-50-40, Debt Modifications and Extinguishments specifically for modifications to or exchanges of revolving-debt arrangements. Based on the guidance, the unamortized deferred costs, any fees paid to the creditor, and any third-party costs associated with Third Amendment, which were incurred as part of the Exchange Transaction, will be deferred and amortized over the term of the Credit Agreement since the borrowing capacity did not change. Deferred financing costs, including the new costs incurred as part of the Exchange Transaction, are recorded as Other assets on the Consolidated Balance Sheets in accordance with ASU No. 2015-15.

On February 14, 2019, Ultra Resources entered into a Fourth Amendment to Credit Agreement (the “Fourth Amendment”) with the RBL Administrative Agent and the RBL Lenders party thereto. Pursuant to the Fourth Amendment, the borrowing base was reaffirmed at $1.3 billion.

The Fourth Amendment also revises certain covenants and other provisions of the Credit Agreement, including, but not limited to:

- Amending the Consolidated Net Leverage Ratio financial covenant as described below. In addition, the consolidated net debt component of the consolidated net leverage ratio may be reduced upon receipt of proceeds from the make-whole litigation as described in Note 12;
- Revising the definition of EBITDAX to (i) provide Ultra Resources with the option of whether to add back certain noncash charges that represent an accrual or reserve for potential cash items in a future period, (ii) provide for the add back of costs and expenses with respect to senior management changes and office closure, consolidation and

relocation, (iii) provide for the add back of costs and expenses with respect to debt restructuring activities (whether consummated or not), (iv) exclude from the deductions certain noncash gains that represent the reversal of an accrual or reserve for any anticipated cash charges in any prior period, and (v) provide for a deduction of cash payments with respect to certain noncash charges that Ultra Resources chose to add back (as described in clause (i)); and

- Amending the Current Ratio financial covenant to exclude from the consolidated current liabilities calculated thereunder, current required amortization payments under the Term Loan Agreement.

At December 31, 2018, Ultra Resources had $104.0 million of outstanding borrowings under the Revolving Credit Facility, total commitments under the Revolving Credit Facility of $325.0 million, and a borrowing base of $1.3 billion. Given the Revolving Credit Agreement was amended in February 2019 and the borrowing base was reaffirmed therein, the next scheduled borrowing base redetermination date is October 1, 2019.

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The Revolving Credit Facility has capacity for Ultra Resources to increase the commitments subject to certain conditions and has $50.0 million of the commitments available for the issuance of letters of credit. The Revolving Credit Facility bears interest either at a rate equal to (a) a customary London interbank offered rate plus an applicable margin that varies from 250 to 350 basis points or (b) the base rate plus an applicable margin that varies from 150 to 250 basis points. If borrowings are outstanding during a period that the Company's consolidated net leverage ratio exceeds 4.00 to 1.00 at the end of any fiscal quarter as described below, the interest rate on such borrowings shall be at a per annum rate that is 0.25% higher than the rate that would otherwise apply until the Company has provided financial statements indicating that the consolidated net leverage ratio no longer exceeds 4.00 to 1.00. The Revolving Credit Facility loans mature on January 12, 2022.

Under the Fourth Amendment, Ultra Resources is required to maintain (i) a minimum interest coverage ratio of 2.50 to 1.00; (ii) a current ratio, including the unused portion of the Revolving Credit Facility of a minimum of 1.00 to 1.00; and (iii) after the Company has obtained investment grade rating an asset coverage ratio of 1.50 to 1.00. In addition, as of the last day of (i) the fiscal quarter ending December 31, 2018, Ultra Resources will not permit the consolidated net leverage ratio to exceed 4.50 to 1.0, (ii) each fiscal quarter ending during the period from March 31, 2019 through June 30, 2019, Ultra Resources will not permit the consolidated net leverage ratio to exceed 4.75 to 1.0, (iii) each fiscal quarter ending during the period from September 30, 2019 through June 30, 2020, Ultra Resources will not permit the consolidated net leverage ratio to exceed 4.90 to 1.0, (iv) the fiscal quarter ending September 30, 2020, Ultra Resources will not permit the consolidated net leverage ratio to exceed 4.50 to 1.0, and (v) the fiscal quarter ending December 31, 2020 and each other fiscal quarter end thereafter, Ultra Resources will not permit the consolidated net leverage ratio to exceed 4.25 to 1.0.

As of December 31, 2018, Ultra Resources' consolidated net leverage ratio was 3.95 to 1.00 and it was in compliance with each of its debt covenants under the Credit Agreement.

Under the Revolving Credit Facility, the Company is subject to the following minimum hedging requirements: through September 29, 2019, the Company is required to hedge a minimum of 65% of the quarterly projected volumes of natural gas from its proved developed producing ("PDP") reserves; and during the period beginning on September 30, 2019 and ending on March 30, 2020, the Company is required to hedge a minimum of 50% of the quarterly projected volumes of natural gas from PDP reserves. Beginning April 1, 2020, the Company will no longer be subject to a minimum hedging requirement.

Ultra Resources is required to pay a commitment fee on the average daily unused portion of the Revolving Credit Facility, which varies based upon a borrowing base utilization grid. Ultra Resources is also required to pay customary letter of credit and fronting fees.

The Revolving Credit Facility also contains customary affirmative and negative covenants, including, among other things, as to compliance with laws (including environmental laws, ERISA and anti-corruption laws), delivery of quarterly and annual financial statements and oil and gas engineering reports, maintenance and operation of property (including oil and gas properties), restrictions on the incurrence of liens, indebtedness, asset dispositions, fundamental changes, restricted payments, hedging requirements and other customary covenants.

The Revolving Credit Facility contains customary events of default and remedies for credit facilities of this nature. If Ultra Resources does not comply with the financial and other covenants in the Revolving Credit Facility, the lenders may, subject to customary cure rights, require immediate payment of all amounts outstanding under the Revolving Credit Facility and any outstanding unfunded commitments may be terminated.

Term Loan. On April 12, 2017, Ultra Resources, as borrower, entered into a Senior Secured Term Loan Agreement (the “Term Loan Agreement”) with the Company and UP Energy Corporation, as parent guarantors, Barclays Bank PLC, as administrative agent (the “Term Loan Administrative Agent”), and the other lenders party thereto (collectively, the “Term Loan Lenders”), providing for senior secured first lien term loans for an aggregate amount of $800.0 million consisting of an initial term loan in the amount of $600.0 million and an incremental term loan in the amount of $200.0 million to be drawn immediately after the funding of the initial term loan. In September 2017, the Company closed an incremental senior secured term loan offering of $175.0 million, increasing total borrowings under the Term Loan Agreement to $975.0 million (the “Term Loan Facility”). As part of the Term Loan Agreement, Ultra Resources agreed to pay an original issue discount equal to one percent of the principal amount, which is included in deferred financing costs.

On December 21, 2018, in connection with the consummation of the Exchange Transaction, Ultra Resources and the parent guarantors entered into the First Amendment to the Term Loan Agreement (the “Term Loan Amendment”) with the Term Loan Administrative Agent and the Term Loan Lenders party thereto. Pursuant to the Term Loan Amendment, the parties agreed, among other things, to amend the Term Loan Agreement to permit the issuance of the Second Lien Notes and the Exchange Transaction, to increase the interest rate payable by 100 basis points, such increase comprising 75 basis points payable in cash and 25 basis points payable in kind, and to revise certain covenants and other provisions of the Term Loan Agreement, including, but not limited to:

- introducing call protection of 102% until the first anniversary of the Exchange Transaction and 101% until the second anniversary of the Exchange Transaction (defined below);
- introducing additional restrictions on the Revolving Credit Facility; including amendments and refinancing of the Revolving Credit Facility as more thoroughly described in the Term Loan Amendment;

- deleting the ability to increase commitments under the Term Loan;
- increasing collateral coverage from 85% to 95% of total PV-9 of Proven Reserves (as defined in the Term Loan Agreement);
- removing the ability to create, invest in and utilize unrestricted subsidiaries;
- further limiting the Company's ability to incur unsecured debt, repay junior debt, and make restricted payments and investments as more thoroughly described in the Term Loan Amendment; and
- providing the ability for the Company to exchange unsecured borrowings to third lien debt within a construct as described in the Term Loan Amendment.

At December 31, 2018, Ultra Resources had $975.0 million in outstanding borrowings under the Term Loan Facility.

Following the Exchange Transaction, the Term Loan Facility bears interest either at a rate equal to (a) a customary London interbank offered rate plus 400 basis points or (b) the base rate plus 300 basis points, in each case, of which 25 basis points of the applicable margin is payable in-kind ("PIK") upon election by Ultra Resources. The Term Loan Facility amortizes in equal quarterly installments in aggregate annual amounts equal to 0.25% of the aggregate principal amount beginning on June 30, 2019. The Term Loan Facility matures on April 12, 2024.

In conjunction with the Exchange Transaction, the Term Loan Amendment was evaluated under FASB ASC 470-50-40, Debt Modifications and Extinguishments. The instrument was determined to not be substantially different and debt modification accounting was applied as this transaction was not a troubled debt restructuring ("TDR"). As a result, no gain or loss was recorded. New fees paid to the Term Loan Lenders totaled $7.2 million and are included as deferred financing costs, which is direct deduction from the carrying amount of the Term Loan.

The Term Loan Facility is subject to mandatory prepayments and customary reinvestment rights. The mandatory prepayments include, without limitation, a prepayment requirement with the total net proceeds from certain asset sales and net proceeds on insurance received on account of any loss of Ultra Resources' property or assets, in each case subject to certain exceptions. In addition, subject to certain exceptions, there is a prepayment requirement if the asset coverage ratio is less than 2.0 to 1.0. To the extent any mandatory prepayments are required, prepayments are applied to prepay the Term Loan Facility.

The Term Loan Agreement also contains customary affirmative and negative covenants, including as to compliance with laws (including environmental laws, ERISA and anti-corruption laws), delivery of quarterly and annual financial statements and oil and gas engineering reports, maintenance and operation of property (including oil and gas properties), restrictions on the incurrence of liens, indebtedness, asset dispositions, fundamental changes, restricted payments and other customary covenants. At December 31, 2018, Ultra Resources was in compliance with all of its debt covenants under the Term Loan Agreement.

The Term Loan Agreement contains customary events of default and remedies for credit facilities of this nature. If Ultra Resources does not comply with the financial and other covenants in the Term Loan Agreement, the lenders may, subject to customary cure rights, require immediate payment of all amounts outstanding under the Term Loan Agreement.

Second Lien Notes. On December 21, 2018, in connection with the consummation of the Exchange Transaction, Ultra Resources issued $545.0 million aggregate principal amount of Second Lien Notes and entered into an Indenture, dated as of December 21, 2018 (the "Second Lien Notes Indenture"), among Ultra Resources, as issuer, the Company and its other subsidiaries, as guarantors, and Wilmington Trust, National Association, as trustee (the "Trustee") and collateral agent.

In January and February 2019, certain holders of the 2022 Notes exchanged approximately $44.6 million aggregate principal amount of 2022 Notes for $27.0 million aggregate principal amount of Second Lien Notes in a series of follow-on debt exchange transactions. Such Second Lien Notes were issued pursuant to the Second Lien Notes Indenture. The Company will evaluate the treatment of the follow-on exchanges under the same accounting literature used in the Exchange Transaction.

The Second Lien Notes will mature on July 12, 2024. Interest on the Second Lien Notes will accrue at (i) an annual rate of 9.00% payable in cash and (ii) an annual rate of 2.00% PIK. The interest payment dates for the Second Lien Notes are January 15 and July 15 of each year, commencing on July 15, 2019.

The Second Lien Notes are senior secured obligations of Ultra Resources and rank senior in right of payment to all of its existing and future unsecured senior debt, to the extent of the value of the collateral pledged under the Second Lien Notes Indenture and related collateral arrangements, senior in right of payment to all of its future subordinated debt, and junior in right of payment to all of its existing and future secured debt of senior priority, to the extent of the value of the collateral pledged thereby. The Second Lien Notes are secured by second priority security interests in substantially all assets of the Company. Payment by Ultra Resources of all amounts due on or in respect of the Second Lien Notes and the performance of Ultra Resources under the Indenture are initially guaranteed by the Company.

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Prior to December 21, 2021, Ultra Resources may, at any time or from time to time, redeem in the aggregate up to 35% of the aggregate principal amount of the Second Lien Notes in an amount no greater than the net cash proceeds of certain equity offerings at a redemption price of 111.000% of the principal amount of the Second Lien Notes, plus accrued and unpaid interest (including PIK interest), if any, to the date of redemption, if at least 65% of the original principal amount of the Second Lien Notes remains outstanding and the redemption occurs within 180 days of the closing of such equity offering. In addition, before December 21, 2019, Ultra Resources may redeem all or a part of the Second Lien Notes at a redemption price equal to the sum of (i) the principal amount thereof, plus (ii) a make-whole premium at the redemption date, plus accrued and unpaid interest (including PIK interest), if any, to the redemption date. In addition, on or after December 21, 2021, Ultra Resources may redeem all or a part of the Second Lien Notes at redemption prices (expressed as percentages of principal amount) equal to 105.500% for the twelve-month period beginning on December 21, 2021, 102.750% for the twelve-month period beginning December 21, 2022, and 100.000% for the twelve-month period beginning December 21, 2023 and at any time thereafter, plus accrued and unpaid interest (including PIK interest), if any, to the applicable redemption date on the Second Lien Notes.

If Ultra Resources experiences certain change of control triggering events set forth in the Second Lien Notes Indenture, each holder of the Second Lien Notes may require the Issuer to repurchase all or a portion of its Second Lien Notes for cash at a price equal to 101% of the aggregate principal amount of such Second Lien Notes, plus any accrued but unpaid interest (including PIK interest) to the date of repurchase.

The Second Lien Notes Indenture contains customary covenants that restrict the ability of Ultra Resources and the guarantors and certain of its subsidiaries to: (i) sell assets and subsidiary equity; (ii) incur or redeem indebtedness; (iii) create or incur certain liens; (iv) enter into affiliate agreements; (v) pay cash dividends, (vi) change the nature of its business or operations, (vii) make certain types of investments, (ix) enter into agreements that restrict distributions from certain restricted subsidiaries and the consummation of mergers and consolidations; (x) consolidate, merge or transfer all or substantially all of the assets of the Company or any Restricted Subsidiary (as defined in the Second Lien Notes Indenture); and (xi) create unrestricted and foreign subsidiaries. The covenants in the Second Lien Notes Indenture are subject to important exceptions and qualifications. Subject to conditions, the Second Lien Notes Indenture provides that the Company and its subsidiaries will no longer be subject to certain covenants when the Second Lien Notes receive investment grade ratings from any two of S&P Global Ratings, Moody’s Investors Service, Inc., and Fitch Ratings, Inc.

The Second Lien Notes Indenture contains customary events of default. Unless otherwise noted in the Second Lien Notes Indenture, upon a continuing event of default, the Trustee, by notice to the Company, or the holders of at least 25% in principal amount of the then outstanding Notes, by notice to the Company and the Trustee, may declare the Second Lien Notes immediately due and payable, except that an event of default resulting from entry into a bankruptcy, insolvency or reorganization with respect to the Company, any Significant Subsidiary (as defined in the Second Lien Notes Indenture) or group of Restricted Subsidiaries (as defined in the Second Lien Notes Indenture), that taken together would constitute a Significant Subsidiary, will automatically cause the Second Lien Notes to become due and payable.

In conjunction with the Exchange Transaction, the portion of the senior Unsecured Notes which were exchanged for Second Lien Notes was accounted for as a TDR. The Company evaluated the quantitative and qualitative factors in the accounting literature and concluded that concessions were granted as the future undiscounted cash flows of the Second Lien Notes was greater than the net carrying value of the senior Unsecured Notes. No gain is recognized, and an effective interest rate is established based on the carrying value of the Second Lien Notes and revised cash flows. The amount of extinguished debt will be amortized over the remaining life of the Second Lien Notes using the effective interest method and recognized as a reduction to interest expense. As a result, our reported interest expense following the Exchange Transaction, will be significantly less than the contractual cash interest payments throughout the term of the Second Lien Notes.

The Exchange Transaction for the Second Lien Notes resulted in recognition of $4.7 million in expenses for the year ended December 31, 2018.

The exchanged debt resulted in a calculation of cancellation of debt income for tax purposes. Our current tax attributes are expected to offset any potential cash tax impacts from the Exchange Transaction. For additional details on the Company's income taxes, refer to Note 10.

Senior Unsecured Notes. On April 12, 2017, Ultra Resources issued $700.0 million of its 2022 Notes and $500.0 million of its 2025 Notes and entered into an Indenture, dated April 12, 2017 (the "Unsecured Notes Indenture"), among Ultra Resources, as issuer, the Company and its other subsidiaries, as guarantors, and Wilmington Trust, National Association, as Trustee. The Unsecured Notes are treated as a single class of securities under the Unsecured Notes Indenture.

On December 21, 2018, the Company completed the Exchange Transaction, pursuant to which the exchanging noteholders exchanged (i) approximately $505 million aggregate principal amount, or 72.1%, of the issued and outstanding 2022 Notes and (ii) $275 million aggregate principal amount, or 55.0%, of the issued and outstanding 2025 Notes for (a) $545.0 million aggregate principal amount of Second Lien Notes and (b) an aggregate of 10,919,499 new warrants of the Company each entitling the holder thereof to purchase one common share of the Company. As a result of the Exchange Transaction, at December 31, 2018, the aggregate principal amounts outstanding under the Unsecured Notes were approximately $195.0 million with respect to the 2022 Notes and $225.0 million with respect to the 2025 Notes.

The 2022 Notes will mature on April 15, 2022. The interest payment dates for the 2022 Notes are April 15 and October 15 of each year. The 2025 Notes will mature on April 15, 2025. The interest payment dates for the 2025 Notes are April 15 and October 15 of each year. Interest will be paid on the Unsecured Notes from the issue date until maturity.

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On December 21, 2018, in connection with the consummation of the Exchange Transaction, Ultra Resources, the Company and its other subsidiaries, as guarantors, and the Trustee entered into the First Supplement Indenture to the Unsecured Indenture (the "Supplemental Indenture"). Pursuant to the Supplemental Indenture, the parties amended the Unsecured Indenture to, among other things, eliminate or amend substantially all of the restrictive covenants contained in the Unsecured Indenture, other than those relating to the payment of principal and interest. The Supplemental Indenture is binding on all Unsecured Notes that remain outstanding.

The Unsecured Notes Indenture contains customary events of default. Unless otherwise noted in the Unsecured Notes Indenture, upon a continuing event of default, the Trustee, by notice to the Company, or the holders of at least 25% in principal amount of the then outstanding Unsecured Notes, by notice to the Company and the Trustee, may, declare the Unsecured Notes immediately due and payable, except that an event of default resulting from entry into a bankruptcy, insolvency or reorganization with respect to the Company, any Significant Subsidiary (as defined in the Unsecured Notes Indenture) or group of Restricted Subsidiaries (as defined in the Unsecured Notes Indenture), that taken together would constitute a Significant Subsidiary, will automatically cause the Unsecured Notes to become due and payable.

7. SHARE BASED COMPENSATION:

Valuation and Expense Information

	Year Ended December 31,		
	2018	2017	2016
Total cost of share-based payment plans	$15,639	$53,952	$8,013
Amounts capitalized in oil and gas properties and equipment	$3,814	$13,975	$2,451
Amounts charged against income, before income tax benefit	$11,825	$39,977	$5,562
Amount of related income tax benefit recognized in income before valuation allowances	$2,483	$15,927	$2,216

Securities Authorized for Issuance Under Equity Compensation Plans

As of December 31, 2018, the Company had the following securities issuable pursuant to outstanding award agreements or reserved for issuance under the Company's previously approved stock incentive plans. Upon exercise, shares issued will be newly issued shares or shares issued from treasury.

Plan Category	Number of Securities Remaining Available for Future Issuance

	Under Equity Compensation Plans (000's)
Equity compensation plans approved by security holders	14,457
Equity compensation plans not approved by security holders	n/a
Total	14,457

Performance Share Plans:

2017 Stock Incentive Plan. In April 2017, the Ultra Petroleum Corp. 2017 Stock Incentive Plan was established by our board of directors (the "Board") pursuant to which 7.5% of the equity of the Company (on a fully-diluted/fully distributed basis) is reserved for grants to be made from time-to-time to the directors, officers, and other employees of the Company (the "Reserve"). During 2017, management incentive grants (the "Initial MIP Grants") were made to members of the Board, officers, and other employees of the Company subject to the conditions and performance requirements provided in the grants, including the limitations that one-third of the Initial MIP Grants will vest, if at all, at such time when the total enterprise value of the Company equals or exceeds $6.0 billion based upon the volume weighted average price of the common stock during a consecutive 30-day period, that one-third of the Initial MIP Grants will vest, if at all, at such time when the total enterprise value of the Company equals or exceeds 110% of $6.0 billion based upon the volume weighted average price of the common stock during a consecutive 30-day period, and, that if any Initial MIP Grants do not vest before April 12, 2023, such Initial MIP Grants shall automatically expire. The balance of the Reserve is available to be granted by the Board from time to time.

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In June 2018, each of the Board and the Compensation Committee of the Board (the "Committee") approved an amendment and restatement of the Ultra Petroleum Corp. 2017 Stock Incentive Plan (as amended and restated, the "A&R Stock Incentive Plan"). The A&R Stock Incentive Plan amends and restates the 2017 Stock Incentive Plan to, among other things:

- provide that consultants, independent contractors and advisors are eligible to participate and receive equity awards in the A&R Stock Incentive Plan;
- limit the aggregate incentive awards available to be granted to any outside director during a single calendar year to a maximum of $750,000;
- revise the definition of a Change of Control to exclude a change in a majority of the members on the Board;
- provide that, with respect to awards granted on or after June 8, 2018, no such awards will vest solely as a result of a Change of Control (as defined in the A&R Stock Incentive Plan) unless expressly provided otherwise in the applicable grant agreement or unless otherwise determined by the Committee; and
- make certain other changes related to revisions to the U.S. Internal Revenue Code.

In July 2018, the Company modified its incentive plan and recipients of the Initial MIP Grants were offered an opportunity to exchange the unvested portion of their Initial MIP Grants for new equity awards of time-based restricted stock units (the "2018 RSUs") effective July 31, 2018 on a one-for-one basis. All 2018 RSUs are time-based awards and vest in equal tranches on May 25, 2019, May 25, 2020, and May 25, 2021. Under FASB ASC Topic 718, Compensation Cost – Stock Compensation ("FASB ASC 718"), the cancellation of an outstanding award of stock-based compensation followed by the issuance of a replacement award is treated as a modification of the original award. The equity award cancellations and subsequent new grants by the Company were considered Type I, probable-to-probable modification. This type represents modifications where the award was likely to vest prior to modification and is still likely to vest after modification. For these types of modifications, the fair value of the award is assessed both prior to modification and after modification. If the fair value after modification exceeds the fair value prior to modification, incremental expense is generated and recognized over the remaining vesting period. The incremental expense recognized from the modification was $0.6 million for the twelve months ended December 31, 2018.

Long Term Incentive Awards. In 2018, the Board approved long-term incentive awards under the A&R Stock Incentive Plan in order to further align the interests of key employees with shareholders and to give key employees the opportunity to share in the long-term performance of the Company when specific corporate financial and operational goals are achieved. The awards cover a performance period of three years and includes time-based and performance-based measures established by the Committee at the beginning of the three-year period.

Stock-Based Compensation Cost:

Market-Based Condition Awards. When vesting of an award of stock-based compensation is dependent, at least in part, on the value of a company's total equity, for purposes of FASB ASC 718, the award is considered to be subject to a "market condition". Because the Company's total equity value is a component of its enterprise value, the awards based on enterprise value are considered to be subject to a market condition. Unlike the valuation of an award that is subject to a service condition (i.e., time vested awards) or a performance condition that is not related to stock price, FASB ASC 718 requires the impact of the market condition to be considered when estimating the fair value of the award. As a result, we have used a Monte Carlo simulation model to estimate the fair value of the awards that include a market condition.

FASB ASC 718 requires the expense for an award of stock-based compensation that is subject to a market condition that can be attained at any point during the performance period to be recognized over the shorter of (a) the period between the date of grant and the date the market condition is attained, and (b) award's derived service period. For purposes of FASB ASC 718, the derived service period represents the duration of the median of the distribution of share price paths on which the market condition is satisfied. That median is the middle share price path (the midpoint of the distribution of paths) on which the market condition is satisfied. The duration is the period of time from the service inception date to the expected date of market condition satisfaction. Compensation expense is recognized regardless of whether the market condition is actually satisfied.

Expense. For the year ended December 31, 2018, the Company recognized $11.8 million in pre-tax compensation expense, of which $10.9 million related to the Initial MIP Grants. For the year ended December 31, 2017, the Company recognized $40.0 million in pre-tax compensation expense, of which $38.5 million related to the Initial MIP Grants. For the year ended December 31, 2016, the Company recognized $5.6 million in pre-tax compensation expense, of which $4.7 million related to the Company's 2015 and 2014 long-term incentive plan awards. The Company expects the total expense associated with the portion of the Initial MIP Grants that vests if the $6.0 billion total enterprise value performance requirement is satisfied to be $21.3 million and the portion of the Initial MIP grants that vests if the $6.6 billion total enterprise value performance requirement is satisfied to be $19.6 million, respectively.

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8. DERIVATIVE FINANCIAL INSTRUMENTS:

Objectives and Strategy: The Company's major market risk exposure is in the pricing applicable to its natural gas and oil production. Realized pricing is currently driven primarily by the prevailing price for the Company's natural gas production. Historically, prices received for natural gas production have been volatile and unpredictable. Pricing volatility is expected to continue. The prices we receive for our production depend on many factors outside of our control, including volatility in the differences between product prices at sales points and the applicable index price.

The Company relies on various types of derivative instruments to manage its exposure to commodity price risk and to provide a level of certainty in the Company's forward cash flows supporting the Company's capital investment program. These types of instruments may include fixed price swaps, costless collars, or basis differential swaps. These contracts are financial instruments and do not require or allow for physical delivery of the hedged commodity. While mitigating the effects of fluctuating commodity prices, these derivative contracts may limit the benefits we would receive from increases in commodity prices above the fixed hedge prices.

The Company's Revolving Credit Facility requires the Company to hedge 65% of forecast proved producing natural gas production, based on its most recent reserve report for 18 months from the end of the given quarter. This requirement is in effect through September 30, 2019. After that time, the requirement decreases to 50% of the estimated proved producing forecast for natural gas through March 31, 2020. This means the Company may unwind hedges after September 30, 2019 at its discretion providing the Company remains hedged at the 50% level for natural gas. Additionally, the Revolving Credit Facility limits the amount of hedging to 85% of forecast production for all products within a given quarter.

Fair Value of Commodity Derivatives: FASB ASC 815 requires that all derivatives be recognized on the balance sheet as either an asset or liability and be measured at fair value. Changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. The Company does not apply hedge accounting to any of its derivative instruments.

Derivative contracts that do not qualify for hedge accounting treatment are recorded as derivative assets and liabilities at fair value on the Consolidated Balance Sheets and the associated unrealized gains and losses are recorded as current expense or income in the Consolidated Statements of Operations. Unrealized gains or losses on commodity derivatives represent the non-cash change in the fair value of these derivative instruments and do not impact operating cash flows on the Consolidated Statements of Cash Flows.

Commodity Derivative Contracts: At December 31, 2018, the Company had the following open commodity derivative contracts to manage commodity price risk. For the fixed price swaps, the Company receives the fixed price for the contract and pays the variable to the counterparty. For the basis swaps, the Company receives a fixed price for the difference between two sales points for a specified commodity volume over a specified time period. For the collars, the Company pays the counterparty if the market price is above the ceiling price and the counterparty pays if the market price is below the floor on a notional quantity. The reference prices of these commodity derivative contracts are typically referenced to index prices published by independent third parties.

Type	Index	Total Volumes (in millions)	Weighted Average Price Per Unit	Fair Value - December 31, 2018 Asset

					(Liability)
Natural Gas fixed price swaps		(Mmbtu)	($/Mmbtu)		
2019	NYMEX-Henry Hub	185.9		$ 2.81	$ (12,832)
2020	NYMEX-Henry Hub	22.8		$ 2.76	$ (4,506)
Natural Gas basis swaps		(Mmbtu)	($/Mmbtu)		
2019	NW Rockies Basis Swap	105.9		$ 0.67	$ (41,286)
Crude oil fixed price swaps		(Bbl)	($/Bbl)		
2019	NYMEX-WTI	1.4		$ 58.45	$ 15,143
2020	NYMEX-WTI	0.1		$ 60.05	$ 994

Type	Index	Total Volumes (in millions)	Weighted Average Floor Price	Weighted Average Ceiling Price	Fair Value - December 31, 2018 Asset (Liability)
Natural Gas collars					
2020	NYMEX	9.1	$2.75	$ 3.19	$ (346)

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Subsequent to December 31, 2018, the Company entered into commodity derivative contracts to manage commodity price risk as detailed and described in Item 7A. "Quantitative and Qualitative Disclosures About Market Risk."

The following table summarizes the pre-tax realized and unrealized gains and losses the Company recognized related to its natural gas derivative instruments in the Consolidated Statements of Operations for the years ended December 31, 2018, 2017 and 2016:

	For the Year Ended December 31,		
Commodity Derivatives:	2018	2017	2016
Realized gain (loss) on commodity derivatives-natural gas (1)	$(77,031)	$11,446	$ —
Realized gain (loss) on commodity derivatives-crude oil(1)	(8,382)	—	—
Unrealized gain (loss) on commodity derivatives (1)	(59,799)	16,966	—
Total gain (loss) on commodity derivatives	$(145,212)	$28,412	$ —

(1) Included in Gain (loss) on commodity derivatives in the Consolidated Statements of Operations.

9. FAIR VALUE MEASUREMENTS:

As required by FASB ASC Topic 820, Fair Value Measurements and Disclosures ("FASB ASC 820"), the Company defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date and establishes a three-level hierarchy for measuring fair value. Fair value measurements are classified and disclosed in one of the following categories:

Level 1: Quoted prices (unadjusted) in active markets for identical assets and liabilities that we have the ability to access at the measurement date.

Level 2: Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are observable for the asset or liability, and inputs that are derived from observable market data by correlation or other means. Instruments categorized in Level 2 include non-exchange traded derivatives such as over-the-counter forwards and swaps.

Level 3: Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity for the asset or liability.

The valuation assumptions the Company has used to measure the fair value of its commodity derivatives were observable inputs based on market data obtained from independent sources and are considered Level 2 inputs (quoted prices for similar assets, liabilities (adjusted) and market-corroborated inputs).

	Level 1	Level 2	Level 3	Total

Assets:								
Current derivative asset	$	—	$	23,374	$	—	$	23,374
Long-term derivative asset (1)		—		1,203		—		1,203
Total derivative instruments	$	—	$	24,577	$	—	$	24,577
Liabilities:								
Current derivative liability	$	—	$	62,350	$	—	$	62,350
Long-term derivative liability (2)		—		5,060		—		5,060
Total derivative instruments	$	—	$	67,410	$	—	$	67,410

(1) Included in Other assets in the Consolidated Balance Sheet.
(2) Included in Other long-term obligations in the Consolidated Balance Sheet.

Assets and Liabilities Measured on a Non-Recurring Basis

The Company uses fair value to determine the value of its asset retirement obligations. The inputs used to determine such fair value under the expected present value technique are primarily based upon internal estimates prepared by reservoir engineers for costs of dismantlement, removal, site reclamation and similar activities associated with the Company's oil and gas properties and would be classified Level 3 inputs.

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Fair Value of Financial Instruments

The estimated fair value of financial instruments is the amount at which the instrument could be exchanged currently between willing parties. The carrying amounts reported in the Consolidated Balance Sheets for cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the immediate or short-term maturity of these financial instruments. The carrying amount of floating-rate debt approximates fair value because the interest rates are variable and reflective of market rates. We use available market data and valuation methodologies to estimate the fair value of our fixed rate debt and the fair values presented in the tables below reflect original maturity dates for each of the debt instruments. The inputs utilized to estimate the fair value of the Company's fixed rate debt are considered Level 2 fair value inputs. This disclosure is presented in accordance with FASB ASC Topic 825, Financial Instruments, and does not impact our financial position, results of operations or cash flows.

	For the Year Ended December 31,			
	2018		2017	
	Principal	Estimated Fair Value	Principal	Estimated Fair Value
Credit Agreement, secured	$104,000	$104,000	$—	$—
Term Loan, secured due 2024	975,000	858,000	975,000	975,000
Second Lien Notes, secured due 2024 [1]	545,000	395,125	—	—
6.875% Senior, unsecured Notes, due 2022	195,035	68,262	700,000	701,750
7.125% Senior, unsecured Notes, due 2025	225,000	69,750	500,000	505,000
Total debt	$2,044,035	$1,495,137	$2,175,000	$2,181,750

(1) The fair value on Second Lien Notes is priced as of January 8, 2019, the first available trade date.

10. INCOME TAXES:

Income before income tax benefit is as follows:

	Year Ended December 31,		
	2018	2017	2016
United States	$86,242	$(197,136)	$134,959
Foreign	(593)	360,982	(79,462)
Total	$85,649	$163,846	$55,497

The consolidated income tax provision (benefit) is comprised of the following:

	Year Ended December 31,		
	2018	2017	2016
Current tax:			
U.S. federal, state and local	$433	$(13,296)	$(72)
Foreign	9	2	(583)
Total current tax provision (benefit)	442	(13,294)	(655)
Deferred tax:			
Foreign	—	—	1
Total deferred tax expense	—	—	1
Total income tax provision (benefit)	$442	$(13,294)	$(654)

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The income tax provision (benefit) from operations differs from the amount that would be computed by applying the U.S. federal income tax rate of 21% to pretax income as a result of the following:

	Year Ended December 31,		
	2018	2017	2016
Income tax provision computed at the U.S. statutory rate	$17,986	$57,346	$19,424
State income tax (benefit) provision net of federal effect	—	(25,519)	(2,335)
Valuation allowance	(30,723)	(562,491)	(31,083)
Tax effect of rate change	—	463,113	—
Sale of non-core assets	5,863	130,552	—
Foreign rate differential	(36)	(3,150)	17,388
Reorganization items	216	(89,327)	—
Equity compensation	2,689	10,778	1,599
Other, net	4,447	5,404	(5,647)
Total income tax provision (benefit)	$442	$(13,294)	$(654)

The tax effects of temporary differences that give rise to significant components of the Company's deferred tax assets and liabilities are as follows:

	December 31,	
	2018	2017
Deferred tax assets:		
Property and equipment	33,953	181,524
Deferred gain	19,874	22,256
U.S. federal tax credit carryforwards	512	987
U.S. interest carryforwards	5,931	—
U.S. net operating loss carryforwards	462,401	450,623
U.S. state net operating loss carryforwards	—	4,038
Non-U.S. net operating loss carryforwards	7,048	6,556
Asset retirement obligations	37,687	36,624
Derivative instruments, net	8,995	—
Debt financing	92,706	—
Incentive compensation	5,370	6,585
Other, net	2,148	1,723
Total deferred tax assets, gross	676,625	710,916
Valuation allowance	(676,625)	(707,348)
Net deferred tax assets	$—	$3,568
Deferred tax liabilities:		
Derivative instruments, net	—	3,568
Net tax liabilities	$—	$3,568

Net tax asset	$—	$—

In assessing the realizability of the deferred tax assets, management considers whether it is more likely than not that some or all of the deferred tax assets will not be realized. The ultimate realization of the deferred tax assets is dependent upon the generation of future taxable income during the periods in which the temporary differences become deductible or before the attributes expire unused. Among other items, management considers the scheduled reversal of deferred tax liabilities, historical taxable income, projected future taxable income, and available tax planning strategies.

At December 31, 2018 and 2017, the Company recorded a valuation allowance against certain deferred tax assets of $0.7 billion and $0.7 billion, respectively. Some or all of this valuation allowance may be reversed in future periods if future taxable income of the appropriate character is available to recognize certain deferred tax assets.

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The Company has a U.S. federal tax net operating loss carryforward of $2.2 billion as of December 31, 2018, which will be carried forward to offset taxable income generated in future years, and if unutilized, will expire between 2033 and 2037 for net operating losses generated in tax years 2017 and earlier. Federal net operating losses generated in tax years 2018 and later carry forward indefinitely and are limited to 80% of taxable income, if utilized. The Company has immaterial Canadian Federal and Provincial and U.S. State tax net operating loss carry forwards that it does not expect to utilize before they expire, as the Company has minimal or no activity in these jurisdictions. The ownership change that occurred as a result of the Company's chapter 11 restructuring did not significantly impair the ability to utilize the net operating loss carryforwards to offset future taxable income. Without regard to the recorded valuation allowance, if the Company experiences an additional ownership change as determined under Section 382 of the Internal Revenue Code, our ability to utilize our substantial net operating loss carryforwards and other tax attributes may be limited, if we can use them at all.

The Company did not have any unrecognized tax benefits and there was no effect on our financial condition or results of operations related to accounting for uncertain tax positions. The amount of unrecognized tax benefits did not change as of December 31, 2018.

Estimated interest and penalties related to potential underpayment on any unrecognized tax benefits are classified as a component of tax expense in the Consolidated Statements of Operations. The Company has not incurred any interest or penalties associated with unrecognized tax benefits.

The Company files a consolidated federal income tax return in the United States, as well as an income tax return in Canada. With certain exceptions, the income tax years 2015 through 2018 remain open to examination by the major taxing jurisdictions in which the Company has business activity. The Company has been notified that Canada intends to audit tax years 2015 and 2016. Management does not expect the results of the audit to materially impact the Company's financial statements.

The undistributed earnings of the Company's U.S. subsidiaries are considered to be indefinitely invested outside of Canada. It is not practical to estimate the amount of unrecognized deferred tax liability related to undistributed foreign earnings at this time. No provision for Canadian income taxes and/or withholding taxes has been provided thereon.

On December 22, 2017, the Tax Act was enacted into law. The new legislation decreased the U.S. corporate federal income tax rate from 35% to 21% effective January 1, 2018. The Company did not have any impact on recorded deferred tax balances as the re-measurement of net deferred tax assets was offset by a change in the valuation allowance. The Tax Act also included a number of other provisions including the elimination of loss carrybacks and limitations on the use of future loss carryforwards, repeal of the "alternative minimum tax" regime, limitations on the deductibility of certain expenses, including net interest expense, and changes in the way capital costs are recovered. These provisions are not expected to have an immediate effect on the Company. The Tax Act did not make significant changes to the Company's ability to deduct intangible development costs or depletion. The Company's significant net operating loss carryforwards generated in 2017 and before are grandfathered under the provisions of the Tax Act and should not be subject to the new limitations imposed by the Tax Act.

As a result of the Tax Act, further clarifications and new regulations to the Tax Act continue to be issued at times. The Company will continue to monitor these new regulations and analyze their applicability and impact on the Company. The SAB 118 period expired, and no adjustments were made to the provisional accounting adjustments reporting in 2017.

11. EMPLOYEE BENEFITS:

The Company sponsors a qualified, tax-deferred savings plan in accordance with provisions of Section 401(k) of the Internal Revenue Code for its employees. Employees may defer 100% of their compensation, subject to limitations. The Company matches all of the employee's contribution up to 5% of compensation, as defined by the plan, along with an employer discretionary contribution of 8%. The expense associated with the Company's contribution was $2.5 million, $2.4 million and $2.3 million for the years ended December 31, 2018, 2017 and 2016, respectively.

12. COMMITMENTS AND CONTINGENCIES:

Leases

Pinedale LGS

During December 2012, the Company sold a system of pipelines and central gathering facilities (the "Pinedale LGS") and certain associated real property rights in the Pinedale Anticline in Wyoming and entered into a long-term, triple net lease agreement (the "Pinedale Lease Agreement") relating to the use of the Pinedale LGS. The Pinedale Lease Agreement provides for an initial term of 15 years and potential successive renewal terms of 5 years or 75% of the then remaining useful life of the Pinedale LGS at the sole discretion of the Company. Annual rent for the initial term under the Pinedale Lease Agreement is $20.0 million (as adjusted annually for changes based on the consumer price index) and may increase when certain volume thresholds are exceeded. The lease is classified as an operating lease. The Company currently projects that lease payments related to the Pinedale Lease Agreement will total approximately $195.7 million.

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All of the Company's lease obligations are related to leases that are classified as operating leases under ASC 840. These leases contain certain provisions that could result in accelerated lease payments. The Company has considered the effect of these provisions on minimum lease payments in its lease classification analysis and has determined that the default provisions do not impact classification of any the Company's operating leases.

Office space lease

The Company maintains office space in Colorado and Wyoming, with total remaining commitments for office leases of $3.9 million at December 31, 2018; ($1.2 million in 2019; $1.1 million in 2020; $1 million in 2021; and $0.6 million in 2022.

During the years ended December 31, 2018, 2017 and 2016, the Company recognized expense associated with its office leases in the amount of $1.6 million, $1.6 million, and $1.5 million, respectively.

Delivery Commitments

With respect to the Company's natural gas production, from time to time the Company enters into transactions to deliver specified quantities of gas to its customers. None of these commitments require the Company to deliver gas or oil produced specifically from any of the Company's properties, and all of these commitments are priced on a floating basis with reference to an index price. In addition, none of the Company's reserves are subject to any priorities or curtailments that may affect quantities delivered to its customers, any priority allocations or price limitations imposed by federal or state regulatory agencies or any other factors beyond the Company's control that may affect its ability to meet its contractual obligations other than those discussed in Part I. Item 1A. "Risk Factors." If for some reason our production is not sufficient to satisfy these commitments, subject to the availability of capital, we could purchase volumes in the market or make other arrangements to satisfy the commitments.

Litigation Matters

Pending Claims – Ultra Resources Indebtedness Claims

The Plan provides for the treatment of claims against our bankruptcy estates, including claims for prepetition liabilities that have not otherwise been satisfied or addressed before we emerged from chapter 11 proceedings. As noted in this Annual Report on Form 10-K, the claims resolution process associated with chapter 11 proceedings is on-going, and we expect it to continue for an indefinite period of time.

Our chapter 11 filings constituted events of default under Ultra Resources' prepetition debt agreements. During our bankruptcy proceedings, many holders of this indebtedness filed proofs of claim with the Bankruptcy Court, asserting claims for the outstanding balance of the indebtedness, unpaid prepetition interest dates, unpaid post-petition interest (including interest at the default rates under the debt agreements), make-whole amounts, and other fees and obligations allegedly arising under the debt agreements. As previously disclosed, in connection with our emergence from bankruptcy and in accordance with the Plan, all of our obligations with respect to Ultra Resources prepetition indebtedness and the associated debt agreements were cancelled, except to the limited extent expressly set forth in the Plan, and the holders of claims related to the indebtedness received payment in full of allowed claims (including with respect to outstanding principal, unpaid prepetition interest, and certain other prepetition fees and obligations arising under the debt agreements). In connection with the confirmation and consummation of the Plan, we entered into a stipulation with the claimants pursuant to which we agreed to establish and fund a $400.0 million reserve account after the Company's emergence from bankruptcy, pending resolution of make-whole and postpetition interest claims. On

April 14, 2017, we funded the account. Following our emergence from bankruptcy, we continued to dispute the claims made by holders of the Ultra Resources' indebtedness for certain make-whole amounts and post-petition interest at the default rates provided for in the debt agreements.

On September 22, 2017, the Bankruptcy Court denied the Company's objection to the pending make-whole and postpetition interest claims. On October 6, 2017, the Bankruptcy Court entered an order requiring the Company to distribute amounts attributable to the disputed claims to the applicable parties. Pursuant to the order, on October 12, 2017, \$399.0 million was distributed from the Reserve Fund to the parties asserting the make-whole and postpetition interest claims and \$1.3 million (the balance remaining after distributions to the parties asserting claims) was returned to the Company. The disbursement of \$399.0 million was comprised of \$223.8 million representing the fees owed under the make-whole claims described above, which are included in reorganization items in the Consolidated Statements of Operations as of December 31, 2017, and \$175.2 million representing the postpetition interest at the default rate, as described above, which is included in interest expense in the Consolidated Statements of Operations as of December 31, 2017. The Company appealed the court order denying its objections to these claims to the United States Court of Appeals for the Fifth Circuit (the "Appellate Court").

During the fourth quarter of 2018, the Company entered into settlement agreements (collectively, the "Settlement Agreements") with holders of certain claims related to Ultra Resources' prepetition indebtedness (the "Claimants") pursuant to which the parties agreed to settle the pending disputes between the Claimants and the Company. Under the terms of the Settlement Agreements, the Claimants collectively agreed to pay approximately \$16.4 million to the Company.

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On January 17, 2019, the Appellate Court issued an opinion vacating the order of the Bankruptcy Court denying the Company's objection to the asserted make-whole and post-petition interest claims and remanding the matter and those determinations to the Bankruptcy Court for further reconsideration. On January 31, 2019, the holders of these claims filed a petition for rehearing en banc. It is not possible to determine the ultimate disposition of these matters at this time.

Royalties

On April 19, 2016, the Company received a preliminary determination notice from the Office of Natural Resources Revenue ("ONRR") asserting that the Company's allocation of certain processing costs and plant fuel use at certain processing plants were impermissibly charged as deductions in the determination of royalties owed under Federal oil and gas leases for the 2010, 2011, and 2012 time periods (the "Audit Period"). ONRR also filed a proof of claim in our bankruptcy proceedings asserting approximately $35.1 million in claims related to these matters. We disputed the preliminary determination and the proof of claim. We notified ONRR of several matters we believe ONRR may not have considered in preparing the preliminary determination notice and the Company continues to believe that natural gas sold during this period was in marketable condition and, therefore, no disallowances were necessary in the calculation of royalties. This claim could ultimately result in us being required to pay additional royalties to ONRR with respect to the Audit Period as well as additional royalties in respect of the years following the Audit Period. The Company is not able to determine the likelihood or range of any additional royalties or, if and when assessed, whether such amounts would be material.

Oil Sales Contract

On April 29, 2016, the Company received a letter from counsel to Sunoco Partners Marketing & Terminals L.P. ("SPMT") asserting that (1) the Company had breached, by anticipatory repudiation, a contract for the purchase and sale of crude oil between Ultra Resources and SPMT and (2) the contract was terminated. In the letter, SPMT demanded payment for damages resulting from the breach in the amount of $38.6 million. On August 31, 2016, SPMT filed a proof of claim with the Bankruptcy Court for $16.9 million. On December 13, 2016, we filed an objection to SPMT's proof of claim, and on December 14, 2016, we filed an adversary proceeding against SPMT related to matters we believe constitute breach of the contract by SPMT during the prepetition period (as amended, the "Sunoco Adversary"). In its April 25, 2017 reply to the Sunoco Adversary complaint, Sunoco asserted a counterclaim for matters addressed in its proof of claim. On October 16, 2018, the Company reached a settlement agreement with SPMT. Under the terms of the agreement, the Company will pay SPMT a total of $2.0 million, of which $1.0 million was paid as of December 31, 2018.

Other Claims

The Company is party to disputes with respect to overriding royalty interests in certain of our operated leases in Pinedale, Wyoming. At this time, no determination of the outcome of these claims can be made, and as no damage claim amount has been asserted by the claimants, we cannot reasonably estimate the potential impact of these claims. We are defending these cases vigorously, and expect these claims to be resolved in our chapter 11 proceedings. The Company is currently involved in various routine disputes and allegations incidental to its business operations. While it is not possible to determine the ultimate disposition of these matters, the Company believes that the resolution of all such pending or threatened litigation is not likely to have a material adverse effect on the Company's financial position or results of operations.

13. CONCENTRATION OF CREDIT RISK:

The Company’s financial instruments that are exposed to concentrations of credit risk consist primarily of trade receivables and commodity derivative contracts associated with the Company’s hedging program. The Company’s revenues related to natural gas and oil sales are derived principally from a diverse group of companies, including major energy companies, natural gas utilities, oil refiners, pipeline companies, local distribution companies, financial institutions and end-users in various industries.

Concentrations of credit risk with respect to receivables is limited due to the large number of customers and their dispersion across geographic areas. Commodity-based contracts may expose the Company to the credit risk of nonperformance by the counterparty to these contracts. This credit exposure to the Company is diversified primarily among as many as ten major investment grade institutions and will only be present if the reference price of natural gas established in those contracts is less than the prevailing market price of natural gas, from time to time.

The Company maintains credit policies intended to monitor and mitigate the risk of uncollectible accounts receivable related to the sale of natural gas, condensate as well as its commodity derivative positions. The Company performs a credit analysis of each of its customers and counterparties prior to making any sales to new customers or extending additional credit to existing customers. Based upon this credit analysis, the Company may require a standby letter of credit or a financial guarantee. The Company did not have any outstanding, uncollectible accounts for its natural gas or oil sales, nor derivative settlements at December 31, 2018.

A significant counterparty is defined as one that individually accounts for 10% or more of the Company’s total revenues during the year. In 2018, the Company had no single customer that represented more than 10% of its total revenues.

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14. 2016/2017 CHAPTER 11 PROCEEDINGS

Voluntary Reorganization Under Chapter 11 and Ability to Continue as a Going Concern

On April 29, 2016 (the "Petition Date"), the Company and its subsidiaries (collectively, "the Debtors") filed voluntary petitions under chapter 11 of title 11 of the United States Code in the United States Bankruptcy Court for the Southern District of Texas (the "Bankruptcy Court"). Our chapter 11 cases were jointly administered under the caption In re Ultra Petroleum Corp., et al, (Case No. 16-32202 (MI). On March 14, 2017, the Bankruptcy Court confirmed our Debtors' Second Amended Joint Chapter 11 Plan of Reorganization (the "Plan"), and on April 12, 2017 (the "Effective Date"), we emerged from bankruptcy.

Plan of Reorganization

Pursuant to the Plan, the significant transactions that occurred upon our emergence from chapter 11 proceedings were as follows:

- On November 21, 2016, we entered into a Plan Support Agreement (as amended, the "PSA") with certain holders of the Company's prepetition indebtedness and outstanding common stock as well as a Backstop Commitment Agreement ("BCA"). Pursuant to the BCA, we agreed to conduct a rights offering for new common stock in the Company to be issued upon the effectiveness of the Plan for an aggregate purchase price of $580.0 million (the "Rights Offering").
    - On February 8, 2017, we entered into a commitment letter with Barclays Bank PLC ("Barclays") (as amended, the "Commitment Letter") pursuant to which, in connection with the consummation of the Plan, Barclays agreed to provide us with secured and unsecured financings in an aggregate amount of up to $2.4 billion (the "Debt Financings").
- On the Effective Date, the principal obligations outstanding of $999.0 million under the prepetition credit agreement and $1.46 billion under the prepetition senior notes, as well as prepetition interest and other undisputed amounts, were paid in full. The Company's obligations under the prepetition credit agreement and the prepetition senior notes were cancelled and extinguished as provided in the Plan.
- On the Effective Date, the claims of $450.0 million related to the unsecured 5.75% Senior Notes due 2018 (the "2018 Notes") and $850.0 million related to the unsecured 6.125% Senior Notes due 2024 (the "2024 Notes") were allowed in full, each holder of a claim related to the 2018 Notes and the 2024 Notes received a distribution of common stock in the amount of such holder's applicable claim, and the Company's obligations under the 2018 Notes and the 2024 Notes were cancelled and extinguished as provided in the Plan.
- On the Effective Date, we consummated the Rights Offering and the Debt Financings and, as noted above, emerged from bankruptcy.

Fresh Start Accounting

We were not required to apply fresh start accounting to our financial statements in connection with our emergence from bankruptcy because the reorganization value of our assets immediately prior to confirmation of the Plan exceeded our aggregate postpetition liabilities and allowed claims.

Bankruptcy Claims Resolution Process

The claims filed against us during our chapter 11 proceedings were voluminous. In addition, claimants may file amended or modified claims in the future, which modifications or amendments may be material. The claims resolution process is on-going, and the ultimate number and amount of prepetition claims is not presently known, nor can the ultimate recovery with respect to allowed claims be presently ascertained.

As a part of the claims resolution process, we are working to resolve differences between amounts we listed in information filed during our bankruptcy proceedings and the amounts of claims filed by our creditors. We have filed, and we will continue to file, objections with the Bankruptcy Court as necessary with respect to claims we believe should be disallowed.

Costs of Reorganization

During 2017, we incurred significant costs associated with our reorganization and the chapter 11 proceedings. For additional information about the costs of our reorganization and chapter 11 proceedings, see “Reorganization items, net” below.

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The following table summarizes the components included in Reorganization items, net in our Consolidated Statements of Operations for the years ended December 31, 2017 and 2016:

	For the Twelve Months Ended December 31,	
	2017	2016
Professional fees	$(66,529)	$(11,781)
Gains (losses) [1]	431,107	—
Deferred financing costs	—	(18,742)
Contract settlements	—	(17,350)
Make-whole fees	(223,838)	—
Other [2]	167	370
Total Reorganization items, net	$140,907	$(47,503)

[1] Gains (losses) represent the net gain on the debt to equity exchange related to the Company's prepetition senior notes.
[2] Cash interest income earned for the period after the Petition Date on excess cash over normal invested capital.

15. SUBSEQUENT EVENTS:

The Company has evaluated the period subsequent to December 31, 2018 for events that did not exist at the balance sheet date but arose after that date and determined that no subsequent events arose that should be disclosed in order to keep the financial statements from being misleading, except as set forth below:

2019 Debt Exchanges

As previously noted, in January and February 2019, certain holders of the 2022 Notes exchanged approximately $44.6 million aggregate principal amount of 2022 Notes for $27.0 million aggregate principal amount of Second Lien Notes in a series of follow-on debt exchange transactions. Such Second Lien Notes were issued pursuant to the Second Lien Notes Indenture.

Make-Whole and Postpetition Interest Claims

As previously disclosed, during the Company's bankruptcy proceedings, many holders of the Company's prepetition indebtedness filed proofs of claim with the Bankruptcy Court, asserting various claims against the Company, including claims for unpaid postpetition interest (including interest at the default rates under the prepetition debt agreements), make-whole amounts, and other fees and obligations allegedly arising under the prepetition debt agreements. The Company disputed the claims made by the holders of Company's prepetition indebtedness for certain make-whole amounts and postpetition interest at the default rates provided for in the prepetition debt agreements. On September 22, 2017, the Bankruptcy Court denied the Company's objection to the pending make-whole and postpetition interest claims. Further, on October 6, 2017, the Bankruptcy Court entered an order requiring the Company to distribute amounts attributable to the disputed claims to the applicable parties. Pursuant to the order, on October 12, 2017, the Company distributed $399.0 million from a $400.0 million reserve fund set up in connection with its emergence from chapter 11 proceedings to the parties asserting the make-whole and postpetition interest claims and $1.3 million (the balance remaining after distributions to the parties asserting claims) was returned to the

Company. The disbursement of $399.0 million was comprised of $223.8 million representing the fees owed under the make-whole claims described above and $175.2 million representing postpetition interest at the default rate.

During the fourth quarter of 2018, the Company entered into settlement agreements (collectively, the “Settlement Agreements”) with holders of certain claims related to Ultra Resources’ prepetition indebtedness (the “Claimants”) pursuant to which the parties agreed to settle the pending disputes between the Claimants and the Company. Under the terms of the Settlement Agreements, the Claimants collectively agreed to pay approximately $16.4 million to the Company.

On January 17, 2019, the Appellate Court issued an opinion vacating the order of the Bankruptcy Court denying the Company’s objection to the asserted make-whole and postpetition interest claims and remanding the matter and those determinations to the Bankruptcy Court for further reconsideration. On January 31, 2019, the holders of these claims filed a petition for rehearing en banc. It is not possible to determine the ultimate disposition of these matters at this time.

Revolving Credit Facility Amendment

As described in Note 6, Ultra Resources entered into a Fourth Amendment to Credit Agreement with the Agent and the Lenders party thereto on February 14, 2019. Pursuant to the Fourth Amendment, the Borrowing Base was reaffirmed at $1.3 billion for the spring 2019 period, providing $325 million of availability to the Company as a result of the semi-annual borrowing base redetermination. The next scheduled semi-annual borrowing base redetermination is scheduled for the fall of 2019.

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The Fourth Amendment also revises certain covenants and other provisions of the Credit Agreement, including, but not limited to:

- amending the Consolidated Net Leverage Ratio financial covenant to provide that, as of the last day of (i) the fiscal quarter ending December 31, 2018, Ultra Resources will not permit the Consolidated Net Leverage Ratio (as defined in the Credit Agreement) to exceed 4.50 to 1.0, (ii) each fiscal quarter ending during the period from March 31, 2019 through June 30, 2019, Ultra Resources will not permit the Consolidated Net Leverage Ratio to exceed 4.75 to 1.0, (iii) each fiscal quarter ending during the period from September 30, 2019 through June 30, 2020, Ultra Resources will not permit the Consolidated Net Leverage Ratio to exceed 4.90 to 1.0, (iv) the fiscal quarter ending September 30, 2020, Ultra Resources will not permit the Consolidated Net Leverage Ratio to exceed 4.5 to 1.0, and (v) the fiscal quarter ending December 31, 2020 and each other fiscal quarter end thereafter, Ultra Resources will not permit the Consolidated Net Leverage Ratio to exceed 4.25 to 1.0. In addition, the consolidated net debt component of the Consolidated Net Leverage Ratio may be reduced if, among other things, any Credit Party (as defined in the Credit Agreement) receives certain settlement proceeds;
- revising the definition of EBITDAX to (i) provide Ultra Resources with the option of whether to add back certain noncash charges that represent an accrual or reserve for potential cash items in a future period, (ii) provide for the add back of costs and expenses with respect to senior management changes and office closure, consolidation and relocation, (iii) provide for the add back of costs and expenses with respect to debt restructuring activities (whether consummated or not), (iv) exclude from the deductions certain noncash gains that represent the reversal of an accrual or reserve for any anticipated cash charges in any prior period, and (v) provide for a deduction of cash payments with respect to certain noncash charges that Ultra Resources chose to add back (as described in clause (i)); and
- amending the Current Ratio financial covenant to exclude from the consolidated current liabilities calculated thereunder, current required amortization payments under the Term Loan Credit Agreement (as defined in the Credit Agreement).

16. SUMMARIZED QUARTERLY FINANCIAL INFORMATION (UNAUDITED):

	2018 1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total
Operating revenues	$225,374	$190,138	$203,776	$273,211	$892,499
Operating expenses	137,686	127,679	126,872	145,506	537,743
Other income (expense), net:					
Interest expense	(35,837)	(37,715)	(38,382)	(36,382)	(148,316)
Loss on commodity derivatives	(6,530)	(47,271)	(21,804)	(69,607)	(145,212)
Contract settlement	—	—	(2,676)	15,332	12,656
Other income (expense), net	2,606	1,981	4,521	2,657	11,765
Total other (expense) income, net	(39,761)	(83,005)	(58,341)	(88,000)	(269,107)
Income (loss) before income tax provision (benefit)	47,927	(20,546)	18,563	39,705	85,649
Income tax provision (benefit)	434	9	—	(1)	442
Net (loss) income	$47,493	$(20,555)	$18,563	$39,706	$85,207
Net income (loss) per common share — basic	$0.24	$(0.10)	$0.09	$0.20	$0.43
Net income (loss) per common share — fully diluted	$0.24	$(0.10)	$0.09	$0.20	$0.43

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	2017 1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total
Operating revenues	$220,958	$212,657	$217,631	$240,627	$891,873
Operating expenses	104,227	134,393	122,394	132,574	493,588
Other income (expense), net:					
Interest expense	(85,447)	(29,425)	(210,107)	(36,388)	(361,367)
Gain (loss) on commodity derivatives	(13,218)	20,717	4,650	16,263	28,412
Contract settlement	(52,707)	—	—	—	(52,707)
Other income, net	2,491	2,665	2,730	2,430	10,316
Total other (expense) income, net	(148,881)	(6,043)	(202,727)	(17,695)	(375,346)
Reorganization items, net	(57,546)	426,816	(227,123)	(1,240)	140,907
Income (loss) before income tax (benefit) provision	(89,696)	499,037	(334,613)	89,118	163,846
Income tax provision (benefit)	2	—	(6,886)	(6,410)	(13,294)
Net (loss) income	$(89,698)	$499,037	$(327,727)	$95,528	$177,140
Net income (loss) per common share — basic	$(1.12)	$2.76	$(1.67)	$0.49	$1.08
Net income (loss) per common share — fully diluted	$(1.12)	$2.76	$(1.67)	$0.49	$1.08

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17. DISCLOSURE ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED):
The following information about the Company's oil and natural gas producing activities is presented in accordance with FASB ASC Topic 932, Oil and Gas Reserve Estimation and Disclosures:

OIL AND GAS RESERVES:

Our policies and practices regarding internal controls over the recording of reserves is structured to objectively and accurately estimate our oil and gas reserves quantities and present values in compliance with the SEC's regulations and GAAP. Our Director of Reservoir and Development is primarily responsible for overseeing the preparation of the Company's reserve estimates and has a Bachelor of Science degree in Petroleum Engineering with over 14 years of experience. The Company's internal controls over reserve estimates include reconciliation and review controls, including an independent internal review of assumptions used in the estimation.

The estimates of proved reserves and future net revenue as of December 31, 2018, are based upon the use of technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information and property ownership interests. The reserves were estimated using deterministic methods; these estimates were prepared in accordance with generally accepted petroleum engineering and evaluation principles. Standard engineering and geoscience methods, such as reservoir modeling, performance analysis, volumetric analysis and analogy, that were considered to be appropriate and necessary to establish reserve quantities and reserve categorization that conform to SEC definitions and rules and regulations, were also used. As in all aspects of oil and natural gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, these estimates necessarily represent only informed professional judgment.

The determination of oil and natural gas reserves is complex and highly interpretive. Assumptions used to estimate reserve information may significantly increase or decrease such reserves in future periods. The estimates of reserves are subject to continuing changes and, therefore, an accurate determination of reserves may not be possible for many years because of the time needed for development, drilling, testing, and studies of reservoirs. From time to time, the Company may adjust the inventory and schedule of its proved undeveloped locations in response to changes in capital budget, economics, new opportunities in the portfolio or resource availability. The Company has not scheduled any proved undeveloped reserves beyond five years nor does it have any proved undeveloped locations that have been part of its inventory of proved undeveloped locations for over five years.

The Company engaged Netherland, Sewell & Associates, Inc. ("NSAI"), a third-party, independent engineering firm, to prepare the reserve estimates for all of the Company's assets for the years ended December 31, 2018, 2017 and 2016 in this annual report.

Our internal professional staff works closely with NSAI to ensure the integrity, accuracy and timeliness of data that is furnished to them for their reserve estimation process. In addition, other pertinent data is provided such as seismic information, geologic maps, well logs, production tests, well performance data, operating procedures and relevant economic criteria. We make available all information requested, including our pertinent personnel, to the external engineers as part of their evaluation of our reserves. The report of NSAI is included as an Exhibit to this annual report.

The reserves estimates shown herein have been independently evaluated by NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are Mr. Sean A. Martin and Mr. Philip R. Hodgson. Mr. Martin, a Licensed

Professional Engineer in the State of Texas (No. 125354), has been practicing consulting petroleum engineering at NSAI since 2014 and has over seven years of prior industry experience. He graduated from graduated from University of Florida in 2007 with a Bachelor of Science Degree in Chemical Engineering. Mr. Hodgson, a Licensed Professional Geoscientist in the State of Texas (No. 1314), has been practicing consulting petroleum geoscience at NSAI since 1998 and has over 14 years of prior industry experience. He graduated from University of Illinois in 1982 with a Bachelor of Science Degree in Geology and from Purdue University in 1984 with a Master of Science Degree in Geophysics. Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Since January 1, 2016, no crude oil, natural gas or NGL reserve information has been filed with, or included in any report to, any federal authority or agency other than the SEC and the Energy Information Administration (“EIA”) of the U.S. Department of Energy. We file Form 23, including reserve and other information, with the EIA.

The following unaudited tables as of December 31, 2018, 2017 and 2016 reflect estimated quantities of proved oil and natural gas reserves for the Company and the changes in total proved reserves as of December 31, 2018, 2017 and 2016. All such reserves were located in the Green River Basin in Wyoming for the year ended December 31, 2018, in the Green River Basin in Wyoming and the Uinta Basin in Utah for the year ended December 31, 2017, and in the Green River Basin in Wyoming, the Appalachian Basin in Pennsylvania and the Uinta Basin in Utah for the year ended December 31, 2016.

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ANALYSES OF CHANGES IN PROVEN RESERVES:

	United States Natural Gas	Oil	NGLs
	(MMcf)	(MBbls)	(MBbls)
Reserves, December 31, 2015	2,336,280	22,175	9,840
Extensions, discoveries and additions	251,634	3,519	530
Sales	—	—	—
Acquisitions	—	—	—
Production	(264,278)	(2,912)	—
Revisions	(2,023)	(1,307)	(467)
Reserves, December 31, 2016	2,321,613	21,475	9,903
Extensions, discoveries and additions	50,312	1,117	—
Sales	(89,315)	—	—
Acquisitions	22,400	153	—
Production	(260,009)	(2,775)	—
Revisions	910,991	7,148	(9,832)
Reserves, December 31, 2017	2,955,992	27,118	71
Extensions, discoveries and additions	85,180	1,086	—
Sales	(4,033)	(3,573)	(71)
Acquisitions	—	—	—
Production	(260,406)	(2,442)	—
Revisions	145,100	1,256	—
Reserves, December 31, 2018	2,921,833	23,445	—

	United States Natural Gas	Oil	NGLs
	(MMcf)	(MBbls)	(MBbls)
Proved:			
Developed	2,336,280	22,175	9,840
Undeveloped	—	—	—
Total Proved — 2015	2,336,280	22,175	9,840
Developed	2,321,613	21,475	9,903
Undeveloped	—	—	—
Total Proved — 2016	2,321,613	21,475	9,903
Developed	2,261,289	21,652	71
Undeveloped	694,703	5,466	—
Total Proved — 2017	2,955,992	27,118	71

Developed	2,243,956	17,876	—
Undeveloped	677,877	5,569	—
Total Proved — 2018	2,921,833	23,445	—

Changes in proved developed reserves: During 2018, substantially all of the changes were attributable to wells drilled in 2018.

Changes in proved undeveloped reserves: The Company's year-end development plans and associated PUDs are consistent with SEC guidelines for PUD development within five years. The Company annually reviews all PUDs to ensure an appropriate development plan exists.

Development plan: The development plan underlying the Company's proved undeveloped reserves, if any, adopted each year by senior management, is based on the best information available at the time of adoption. As factors such as commodity price, service costs, performance data, and asset mix are subject to change, the Company occasionally revises its development plan. Development plan revisions include deferrals, removals, and substitutions of previously scheduled PUD reserve locations. These occasional changes achieve the purpose of maximizing profitability and are in the best interest of the Company's shareholders.

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STANDARDIZED MEASURE:

The following table sets forth a standardized measure of the estimated discounted future net cash flows attributable to the Company's proved reserves. Natural gas prices have fluctuated widely in recent years. The calculated weighted average sales prices utilized for the purposes of estimating the Company's proved reserves and future net revenues at December 31, 2018, 2017 and 2016 was $2.59, $2.59 and $2.07 per Mcf, respectively, for natural gas, and $63.49, $48.05 and $37.90 per barrel, respectively, for oil and condensate. In 2014, the Company acquired contracts related to NGLs providing an annual election to process NGLs beginning in 2017. In 2017, the Company renegotiated its existing gas processing contracts in Wyoming. The new gas processing contracts are keep-whole contracts in which the Company shares in the economic benefit of processing and accordingly does not include the NGL volumes in its reserves.

The future production and development costs represent the estimated future expenditures to be incurred in developing and producing the proved reserves, assuming continuation of existing economic conditions. Future income tax expense was computed by applying statutory income tax rates to the difference between pretax net cash flows relating to the Company's proved reserves and the tax basis of proved properties and available operating loss carryovers.

	As of December 31,		
	2018	2017	2016
Future cash inflows	$9,195,725	$8,965,949	$5,812,234
Future production costs	(3,337,779)	(3,587,581)	(2,665,082)
Future development costs	(1,133,103)	(1,001,024)	(355,923)
Future income taxes	(180,057)	—	—
Future net cash flows	4,544,786	4,377,344	2,791,229
Discount at 10%	(2,139,303)	(1,993,016)	(1,100,283)
Standardized measure of discounted future net cash flows	$2,405,483	$2,384,328	$1,690,946

The estimate of future income taxes is based on the future net cash flows from proved reserves adjusted for the tax basis of the oil and gas properties but without consideration of general and administrative and interest expenses.

SUMMARY OF CHANGES IN THE STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS:

	December 31,		
	2018	2017	2016
Standardized measure, beginning	$2,384,328	$1,690,946	$1,865,649
Net revisions of previous quantity estimates	160,405	840,505	(9,623)
Extensions, discoveries and other changes	90,609	53,549	209,603
Sales of reserves in place	(34,768)	(83,887)	—
Acquisition of reserves	—	21,903	—
Changes in future development costs	(235,205)	(329,635)	11,556
Sales of oil and gas, net of production costs	(593,134)	(589,621)	(454,725)

Net change in prices and production costs	362,084	572,224	(72,939)
Development costs incurred during the period that reduce future development costs	251,621	8,007	22,523
Accretion of discount	238,433	169,095	186,565
Net changes in production rates and other	(189,017)	31,242	(67,663)
Net change in income taxes	(29,873)	—	—
Aggregate changes	21,155	693,382	(174,703)
Standardized measure, ending	$2,405,483	$2,384,328	$1,690,946

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There are numerous uncertainties inherent in estimating quantities of proved reserves and projected future rates of production and timing of development expenditures, including many factors beyond the control of the Company. The reserve data and standardized measures set forth herein represent only estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates of different engineers often vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of such estimates. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. Further, the estimated future net revenues from proved reserves and the present value thereof are based upon certain assumptions, including geologic success, prices, future production levels and costs that may not prove correct over time. Predictions of future production levels are subject to great uncertainty, and the meaningfulness of such estimates is highly dependent upon the accuracy of the assumptions upon which they are based. Historically, oil and natural gas prices have fluctuated widely.

COSTS INCURRED IN OIL AND GAS EXPLORATION AND DEVELOPMENT ACTIVITIES:

	Years Ended December 31,		
	2018	2017	2016
United States			
Property Acquisitions:			
Unproved	$1,468	$1,399	$983
Proved	1,090	9,147	—
Exploration*	156,718	510,710	224,277
Development	266,905	35,934	44,300
Total	$426,181	$557,190	$269,560

* Exploration costs (as defined in Regulation S-X) includes costs spent on development of unproved reserves in the Pinedale Field.

RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES:

	Years Ended December 31,		
	2018	2017	2016
United States			
Oil and gas revenue	$892,499	$891,873	$721,091
Production expenses	(299,365)	(292,095)	(266,366)
Depletion and depreciation	(204,255)	(161,945)	(125,121)
Income tax benefit (expense)	(2)	(168,355)	83,112
Total	$388,877	$269,478	$412,716

CAPITALIZED COSTS RELATING TO OIL AND GAS PRODUCING ACTIVITIES:

	December 31, 2018	2017
Proven Properties:		
Acquisition, equipment, exploration, drilling and environmental costs	$11,577,281	$11,215,563
Less: accumulated depletion, depreciation and amortization	(10,079,554)	(9,890,495)
Total Oil and gas properties, net	$1,497,727	$1,325,068

18. SUPPLEMENTAL FINANCIAL STATEMENT INFORMATION:

Following are the financial statements of Ultra Petroleum Corp. (the “Parent Company”), which are included to provide additional information with respect to the Parent Company’s results of operations, financial position and cash flows on a stand-alone basis:

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CONDENSED STATEMENT OF OPERATIONS

	Year Ended December 31,		
	2018	2017	2016
General and administrative expense	$549	$428	$650
Other income (expense):			
Interest expense (excludes contractual interest expense of $52.4 million for the year ended December 31, 2016)	—	(71,876)	(26,590)
Income (loss) from unconsolidated affiliates	85,809	(183,840)	157,450
Guarantee fee income	—	—	6,073
Other expense	(44)	90	(64,888)
Reorganization items, net	—	433,196	(15,827)
Income before income taxes	85,216	177,142	55,568
Income tax provision (benefit)	9	2	(583)
Net income	$85,207	$177,140	$56,151

CONDENSED BALANCE SHEET

	December 31, 2018	December 31, 2017
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 570	$ 803
Accounts receivable from related companies	29,939	29,940
Other current assets	—	—
Total current assets	30,509	30,743
Other non-current assets	—	—
Total assets	$ 30,509	$ 30,743
LIABILITIES AND SHAREHOLDERS’ EQUITY		
Current liabilities:		
Accrued and other current liabilities	$ —	$ 21
Total current liabilities	—	21
Advances from unconsolidated affiliates	1,079,131	1,185,359
Total liabilities	1,079,131	1,185,380
Total shareholders’ deficit	(1,048,622)	(1,154,637)
Total liabilities and shareholders’ equity	$ 30,509	$ 30,743

CONDENSED STATEMENT OF CASH FLOWS

	Year Ended December 31,		
	2018	2017	2016
Net cash (used in) operating activities	$(234)	$(2,206)	$(21,309)
Investing Activities:			
Investment in subsidiaries	(3,293)	(588,677)	—
Dividends received	—	—	24,089
Net cash (used in) provided by investing activities	(3,293)	(588,677)	24,089
Financing activities:			
Deferred financing costs	—	—	—
Shares issued	3,294	573,774	—
Repurchased shares/net share settlements	—	14,903	43
Shares re-issued from treasury	—	—	(337)
Net cash provided by (used in) financing activities	3,294	588,677	(294)
(Decrease) increase in cash during the period	(233)	(2,206)	2,486
Cash and cash equivalents, beginning of period	803	3,009	523
Cash and cash equivalents, end of period	$570	$803	$3,009

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Item 9. Change in and Disagreements with Accountants on Accounting and Financial Disclosures.
None.

Item 9A. Controls and Procedures.
Management's Report on Internal Control Over Financial Reporting

Management's Report on Internal Control Over Financial Reporting is included on page 59 of this Form 10-K.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended December 31, 2018 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Evaluation of Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our chief executive officer and our chief financial officer, we evaluated the effectiveness of our disclosure controls and procedures, as such term is defined under Rule 13a-15(e) and Rule 15d-15(e) promulgated under the Exchange Act. Based on that evaluation, our chief executive officer and our chief financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2018, the end of the period covered by this report. The evaluation considered the procedures designed to ensure that information required to be disclosed by us in the reports filed or submitted by us under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms and communicated to our management as appropriate to allow timely decisions regarding required disclosure.

Item 9B. Other Information.
None.

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Part III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this item is incorporated herein by reference to the Company's definitive proxy statement, which will be filed not later than 120 days after December 31, 2018.

The Company has adopted a code of ethics that applies to the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer. The full text of such code of ethics is posted on the Company's website at www.ultrapetroleum.com, and is available free of charge in print to any shareholder who requests it. Requests for copies should be addressed to the Secretary at 116 Inverness Drive East, Suite 400, Englewood, Colorado 80112.

Item 11. Executive Compensation.

The information required by this item is incorporated herein by reference to the Company's definitive proxy statement, which will be filed not later than 120 days after 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 herein by reference to the Company's definitive proxy statement, which will be filed not later than 120 days after December 31, 2018.

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

The information required by this item is incorporated herein by reference to the Company's definitive proxy statement, which will be filed not later than 120 days after December 31, 2018.

Item 14. Principal Accounting Fees and Services.

The information required by this item is incorporated herein by reference to the Company's definitive proxy statement, which will be filed not later than 120 days after December 31, 2018.

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Part IV

Item 15. Exhibits, Financial Statement Schedules.

The following documents are filed as part of this report:

1. Financial Statements: See Part II, Item 8. "Financial Statements and Supplementary Data."

2. Financial Statement Schedules: Financial statement schedules required under SEC rules but not included in this Form 10-K are omitted because they are not applicable or the required information is contained in the consolidated financial statements or notes thereto.

3. Index to Exhibits. The following documents are included as exhibits to this Form 10-K. Exhibits incorporated by reference are duly noted as such.

Exhibit Number	Description
2.1	Debtors' Second Amended Joint Chapter 11 Plan of Reorganization (incorporated by reference to Exhibit A of the Order Confirming Debtors' Second Amended Joint Chapter 11 Plan of Reorganization, filed as Exhibit 99.1 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on March 16, 2017).
3.1	Articles of Reorganization of Ultra Petroleum Corp. (incorporated by reference to Exhibit 3.1 of the Registration Statement on Form 8-A filed by Ultra Petroleum Corp. on April 12, 2017).
3.2	Second Amended and Restated By-Law No. 1 of Ultra Petroleum Corp. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on March 12, 2018).
4.1	Specimen Common Share Certificate (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on April 18, 2017).
4.2	Indenture dated April 12, 2017 among Ultra Resources, Inc., Ultra Petroleum Corp., the subsidiary guarantors party thereto, and Wilmington Trust, National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on April 18, 2017).
4.3	First Supplemental Indenture dated as of December 21, 2018, to Indenture dated as of April 12, 2017, among Ultra Resources, Inc., Ultra Petroleum Corp., the subsidiary guarantors party thereto, and Wilmington Trust, National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on December 26, 2018).
4.4	Indenture dated as of December 21, 2018, among Ultra Resources, Inc., Ultra Petroleum Corp., the subsidiary guarantors party thereto, and Wilmington Trust, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on December 26, 2018).

4.5	First Supplemental Indenture dated as of January 22, 2019, to Indenture dated as of December 21, 2018, among Ultra Petroleum Corp., Ultra Resources, Inc., the subsidiary guarantors party thereto, and Wilmington Trust, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on January 25, 2019).
4.6	Second Supplemental Indenture dated as of January 23, 2019, to Indenture dated as of December 21, 2018, among Ultra Petroleum Corp., Ultra Resources, Inc., the subsidiary guarantors party thereto, and Wilmington Trust, National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on January 25, 2019).
*4.7	Third Supplemental Indenture dated as of February 4, 2019, to Indenture dated as of December 21, 2018, among Ultra Petroleum Corp., Ultra Resources, Inc., the subsidiary guarantors party thereto, and Wilmington Trust, National Association, as trustee.
*4.8	Fourth Supplemental Indenture dated as of February 13, 2019, to Indenture dated as of December 21, 2018, among Ultra Petroleum Corp., Ultra Resources, Inc., the subsidiary guarantors party thereto, and Wilmington Trust, National Association, as trustee.

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*4.9 Fifth Supplemental Indenture dated as of February 15, 2019, to Indenture dated as of December 21, 2018, among Ultra Petroleum Corp., Ultra Resources, Inc., the subsidiary guarantors party thereto, and Wilmington Trust, National Association, as trustee.

10.1 Senior Secured Term Loan Agreement dated as of April 12, 2017, among Ultra Petroleum Corp. and UP Energy Corporation, as parent guarantor, Ultra Resources Inc., as borrower, Barclays Bank PLC, as administrative agent and the lenders and other parties party thereto. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on April 18, 2017).

10.2 First Amendment to Senior Secured Term Loan Agreement dated as of December 28, 2018, among Ultra Resources Inc., as borrower, Ultra Petroleum Corp. and UP Energy Corporation, as parent guarantor, Barclays Bank PLC, as administrative agent and the lenders and other parties party thereto (incorporated by reference to Exhibit 10.5 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on December 26, 2018).

10.3 Credit Agreement dated as of April 12, 2017, among Ultra Petroleum Corp. and UP Energy Corporation, as parent guarantor, Ultra Resources, Inc., as borrower, Bank of Montreal, as administrative agent, and the lenders and other parties party thereto. (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on April 18, 2017).

10.4 First Amendment to Credit Agreement dated as of June 6, 2017, among Ultra Resources Inc., as borrower, Bank of Montreal, as administrative agent, and the lenders and other parties party thereto (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on June 12, 2017).

10.5 Second Amendment to Credit Agreement dated as of April 19, 2018, among Ultra Resources, Inc. as borrower, Bank of Montreal, as administrative agent, and each of the lenders and other parties party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on April 20, 2018).

10.6 Third Amendment to Credit Agreement dated as of December 21, 2018, among Ultra Resources, Inc. as borrower, Bank of Montreal, as administrative agent, and each of the lenders and other parties party thereto (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on December 26, 2018).

10.7 Fourth Amendment to Credit Agreement dated as of February 14, 2019, among Ultra Resources, Inc. as borrower, Bank of Montreal, as administrative agent, and each of the lenders and other parties party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on February 19, 2019).

10.8 Guaranty and Collateral Agreement dated as of April 12, 2017, among Ultra Petroleum Corp. and the other parties signatory thereto, as grantors, and Bank of Montreal, as collateral agent. (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on April 18, 2017).

10.9 Second Lien Guaranty and Collateral Agreement dated as of December 21, 2018, among Ultra Petroleum Corp. and the other parties signatory thereto, as grantors, and Wilmington Trust, National Association, as collateral agent (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on December 26, 2018).

10.10 First Lien/Second Lien Intercreditor Agreement dated as of December 21, 2018, by and among Bank of Montreal, as revolving administrative agent and as collateral agent for the senior secured parties, Barclays Bank PLC, as term loan administrative agent, Wilmington Trust, National Association, as the second lien collateral agent for the junior priority parties, Ultra Resources Inc., as borrower, and the other grantors party thereto (incorporated by reference to Exhibit 10.6 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on December 26, 2018).

10.11 Registration Rights Agreement dated as of April 12, 2017 by and among Ultra Petroleum Corp. and the other parties signatory thereto (incorporated by reference to Exhibit 10.1 to the Registration Statement on Form 8-A filed by Ultra Petroleum Corp. on April 12, 2017).

10.12 Sale and Purchase Agreement dated October 18, 2013 between Axia Energy, LLC and UPL Three Rivers Holdings, LLC (incorporated by reference to Exhibit 1.1 of the Company's Report on Form 8-K filed by Ultra Petroleum Corp. on October 24, 2013).

10.13 Purchase and Sale Agreement dated August 13, 2014 between Ultra Petroleum Corp. and SWEPI LP (incorporated by reference from Exhibit 1.1 of the Company's Report on Form 8-K filed by Ultra Petroleum Corp. on August 19, 2014).

10.14 Cooperation Agreement dated January 29, 2018 among Ultra Petroleum Corp. and Fir Tree Capital Management LP (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on January 30, 2018).

10.15 Exchange Agreement dated as of October 17, 2018, among Ultra Petroleum Corp., Ultra Resources, Inc., certain subsidiary guarantors thereto and certain noteholders (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on October 17, 2018).

10.16 Exchange Agreement dated as of December 17, 2018, among Ultra Petroleum Corp., Ultra Resources, Inc., certain subsidiary guarantors thereto and certain noteholders (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on December 26, 2018).

10.17 Warrant Agreement dated as of December 21, 2018, among Ultra Petroleum Corp., Computershare Inc. and Computershare Trust Company N.A., as warrant agent (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on December 26, 2018).

10.18 Director Nomination Agreement dated as of December 21, 2018, among Ultra Petroleum Corp. and the holders of 9.00% Cash / 2.00% PIK Senior Secured Second Lien Notes due 2024 of Ultra Resources, Inc. signatory thereto (incorporated by reference to Exhibit 10.7 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on December 26, 2018).

#10.19 Ultra Petroleum Corp. 2017 Stock Incentive Plan, as amended and restated June 8, 2018 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on June 14, 2018).

#10.20 Ultra Petroleum Corp. Annual Incentive Plan (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on July 12, 2018).

#10.21 Form of Restricted Stock Unit Agreement (incorporated by reference to Exhibit 10.2 to the Registration Statement on Form S-8 filed by Ultra Petroleum Corp. on April 12, 2017).

#10.22 Form of Restricted Stock Unit Agreement (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on June 14, 2018).

#10.23 Form of Restricted Stock Unit Grant Agreement (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on July 12, 2018).

#10.24 Form of Restricted Stock Unit Grant Agreement (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q filed by Ultra Petroleum Corp. on November 9, 2018).

10.25 First Amendment to Plan Support Agreement effective as of February 10, 2017, by and among Ultra Petroleum Corp. and the other Debtors, on the one hand, and certain holders of common stock in Ultra Petroleum Corp. and debt securities issued by Ultra Petroleum Corp., on the other hand (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on February 15, 2017).

#10.26 Employment Agreement of Michael D. Watford dated November 6, 2017 (incorporated by reference to Exhibit 10.8 to the Quarterly Report on Form 10-Q filed by Ultra Petroleum Corp. on November 9, 2017).

#10.27 Employment Agreement of Garland R. Shaw dated November 6, 2017 (incorporated by reference to Exhibit 10.9 to the Quarterly Report on Form 10-Q filed by Ultra Petroleum Corp. on November 9, 2017).

#10.28 Employment Agreement of Brad Johnson dated November 6, 2017 (incorporated by reference to Exhibit 10.10 to the Quarterly Report on Form 10-Q filed by Ultra Petroleum Corp. on November 9, 2017).

#10.29 Employment Agreement of Kent Rogers dated November 6, 2017 (incorporated by reference to Exhibit 10.11 to the Quarterly Report on Form 10-Q filed by Ultra Petroleum Corp. on November 9, 2017).

#10.30	Employment Agreement of Patrick Ash dated November 6, 2017 (incorporated by reference to Exhibit 10.12 to the Quarterly Report on Form 10-Q filed by Ultra Petroleum Corp. on November 9, 2017).
#10.31	Employment Agreement of Garrett B. Smith dated November 6, 2017 (incorporated by reference to Exhibit 10.13 to the Quarterly Report on Form 10-Q filed by Ultra Petroleum Corp. on November 9, 2017).
#10.32	Separation Agreement dated February 23, 2018 among Ultra Petroleum Corp. and Michael D. Watford (incorporated by reference to Exhibit 10.17 to the Annual Report on Form 10-K filed by Ultra Petroleum Corp. on February 28, 2018).
#10.33	Transition Agreement dated as of September 5, 2018, by and between Ultra Petroleum Corp. and Garland R. Shaw (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q filed by Ultra Petroleum Corp. on November 8, 2018).
#10.34	Transition Agreement dated as of September 5, 2018, by and between Ultra Petroleum Corp., and Garrett B. Spear-Smith (incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q filed by Ultra Petroleum Corp. on November 8, 2018).
#10.35	Employment Agreement of Jerald J. "Jay" Stratton dated May 31, 2018 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on June 1, 2018).
#10.36	Employment Agreement of Maree K. Delgado dated August 15, 2018 (incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q filed by Ultra Petroleum Corp. on November 9, 2018).
#*10.37	Employment Agreement of David W. Honeyfield dated as of November 5, 2018.
#*10.38	Ultra Petroleum Corp. Directors Deferred Compensation Plan.
*21.1	List of Subsidiaries of Ultra Petroleum Corp.
*23.1	Consent of Netherland, Sewell & Associates, Inc.
*23.2	Consent of Ernst & Young LLP.
*31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
**32.1	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
**32.2	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*99.1	Reserve Report Summary prepared by Netherland, Sewell & Associates, Inc. as of December 31, 2018.
**101.INS	XBRL Instance Document

**101.SCH	XBRL Taxonomy Extension Schema Document
**101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
**101.LAB	XBRL Taxonomy Extension Label Linkbase Document
**101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
**101.DEF	XBRL Taxonomy Extension Definition

*	Filed herewith
**	Furnished herewith
#	Management contract or compensatory plan or arrangement required to be filed as an exhibit to this Form 10-K pursuant to Item 15(b).

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SIGNATURES

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

ULTRA PETROLEUM CORP.

By: /s/ Brad Johnson
Name: Brad Johnson
Title: President and Chief Executive Officer

Date: March 7, 2019

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/ Brad Johnson	President, Chief Executive Officer and Director (principal executive officer)	March 7, 2019
Brad Johnson		
/s/ David W. Honeyfield	Senior Vice President and Chief Financial Officer	March 7, 2019
David W. Honeyfield	(principal financial officer)	
/s/ Maree K. Delgado	Vice President and Chief Accounting Officer	March 7, 2019
Maree K. Delgado	(principal accounting officer)	
/s/ Evan Lederman	Chairman of the Board	March 7, 2019
Evan Lederman		
/s/ Neal P. Goldman	Director	March 7, 2019
Neal P. Goldman		
/s/ Michael J. Keeffe	Director	March 7, 2019
Michael J. Keeffe		
/s/ Stephen J. McDaniel	Director	March 7, 2019

Stephen J. McDaniel

/s/ Alan J. Mintz	Director	March 7, 2019
Alan J. Mintz		
/s/ Edward A. Scoggins, Jr.	Director	March 7, 2019
Edward A. Scoggins, Jr.		

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Certain Definitions

Terms used to describe quantities of oil and natural gas and marketing

- Bbl — One stock tank barrel, or 42 U.S. gallons liquid volume, of crude oil or other liquid hydrocarbons.
- Bcf — One billion cubic feet of natural gas.
- Bcfe — One billion cubic feet of natural gas equivalent.
- Tcfe — One trillion cubic feet of natural gas equivalent.
- BOE — One barrel of oil equivalent, determined by using the ratio of one barrel of oil or NGLs to six Mcf of gas.
- BTU — British Thermal Unit.
- Condensate — An oil-like, liquid hydrocarbon which is produced in association with natural gas production that condenses from natural gas as it is produced and delivered into a separator or similar equipment prior to the delivery of such natural gas to the natural gas gathering pipeline system.
- MBbl — One thousand barrels of crude oil or other liquid hydrocarbons.
- Mcf — One thousand cubic feet of natural gas.
- Mcfe — One thousand cubic feet of natural gas equivalent, converting oil, condensate or NGLs to natural gas at the ratio of one barrel of oil, condensate or NGLs to six Mcf of natural gas.
- MMBbl — One million barrels of crude oil or other liquid hydrocarbons.
- MMcf — One million cubic feet of natural gas.
- MMBTU — One million British Thermal Units.
- NGL or NGLs — Natural gas liquids, which are expressed in barrels.

Terms used to describe the Company's interests in wells and acreage

- Completion — Installation of permanent equipment for production of oil or gas, or, in the case of a dry well, to reporting to the appropriate authority that the well has been abandoned.
- Dry Well — An exploratory, development, or extension well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.
- Gross oil and natural gas wells or acres — The Company's gross wells or gross acres represent the total number of wells or acres in which the Company owns a working interest.
- Net oil and natural gas wells or acres — Determined by multiplying "gross" oil and natural gas wells or acres by the working interest that the Company owns in such wells or acres represented by the underlying properties.
- Prospect — A location where hydrocarbons such as oil and gas are believed to be present in quantities which are economically feasible to produce.
- Undeveloped acreage — Acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or gas regardless of whether such acreage contains proved reserves.

Terms used to assign a present value to the Company's reserves

- Standardized measure of discounted future net cash flows, after income taxes — The present value, discounted at 10%, of the after tax future net cash flows attributable to estimated net proved reserves. The Company calculates this amount by assuming that it will sell the oil and natural gas production attributable to the proved reserves estimated in its independent engineer's reserve report for the oil and natural gas spot prices based on the average price during the 12-month period before the ending date of the period covered by the report determined as an un-weighted, arithmetic average of the first-day-of-the-month price for each month within such period, adjusted for energy content, quality and transportation. The Company also assumes that the cost to produce the reserves will remain constant at the costs prevailing on the date of the report. The assumed costs are subtracted from the assumed revenues resulting in a stream of future net cash flows. Estimated future income taxes, using rates in effect on the date of the report, are deducted from the net cash flow stream. The after-tax cash flows are discounted at 10% to result in the standardized measure of the Company's proved reserves.

- Standardized measure of discounted future net cash flows before income taxes — The discounted present value of proved reserves is identical to the standardized measure described above, except that estimated future income taxes are not deducted in calculating future net cash flows. The Company discloses the discounted present value without deducting estimated income taxes to provide what it believes is a more comparative basis of its reserves to the producers who may have different income tax rates.

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Terms used to classify the Company's reserve quantities

The Securities and Exchange Commission ("SEC") definition of proved oil and natural gas reserves, per Regulation S-X, is as follows:

Economically producible — A resource that generates revenue that exceeds (or is reasonably expected to exceed) costs of the operation.

Estimated ultimate recovery — The sum of reserves remaining as of a given date and cumulative production as of that date.

Proved oil and gas reserves — Proved oil and natural gas reserves are those quantities of oil and gas, which, by analysis of available 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 regulation — before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.

The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

The area of the reservoir considered as proved includes all of the following:

a. The area identified by drilling and limited fluid contacts, if any,

b. Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establish a lower contact with reasonable certainty.

Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

Reserves that can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when both of the following occur:

a. Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based.

b. The project has been approved for development by all necessary parties and entities, including governmental entities.

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

Proved developed oil and gas reserves — Proved oil and gas reserves that can be expected to be recovered:

a. Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well.

b. Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Proved undeveloped oil and gas reserves — Proved oil and gas reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

Under no circumstances are estimates for proved undeveloped reserves attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

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

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

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

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

Terms used to describe the legal ownership of the Company’s oil and natural gas properties

- Revenue interest — The amount of the interest owned in the proceeds derived from a producing well less all royalty interests.
- Working interest — A real property interest entitling the owner to receive a specified percentage of the proceeds of the sale of oil and natural gas production or a percentage of the production, but requiring the owner of the working interest to bear the cost to explore for, develop and produce such oil and natural gas. A working interest owner who owns a portion of the working interest may participate either as operator or by voting his percentage interest to approve or disapprove the appointment of an operator and drilling and other major activities in connection with the development and operation of a property.

Terms used to describe seismic operations

- Seismic data — Oil and natural gas companies use seismic data as their principal source of information to locate oil and natural gas deposits, both to aid in exploration for new deposits and to manage or enhance production from known reservoirs. To gather seismic data, an energy source is used to send sound waves into the subsurface strata. These waves are reflected back to the surface by underground formations, where they are detected by geophones which digitize and record the reflected waves. Computers are then used to process the raw data to develop an image of underground formations.
- 2-D seismic data — 2-D seismic survey data has been the standard acquisition technique used to image geologic formations over a broad area. 2-D seismic data is collected by a single line of energy sources which reflect seismic waves to a single line of geophones. When processed, 2-D seismic data produces an image of a single vertical plane of sub-surface data.
- 3-D seismic data — 3-D seismic data is collected using a grid of energy sources, which are generally spread over several miles. A 3-D survey produces a three-dimensional image of the subsurface geology by collecting seismic data along parallel lines and creating a cube of information that can be divided into various planes, thus improving visualization. Consequently, 3-D seismic data is generally considered a more reliable indicator of potential oil and

natural gas reservoirs in the area evaluated.

Other Terms

- All-in costs — For any period, means the sum of lease operating expenses, liquids gathering system operating lease expense, severance taxes, gathering costs, transportation charges, depletion, depreciation and amortization, interest expense and general and administrative expenses divided by production on an Mcfe basis during the period.
- Cash costs — For any period, means the sum of lease operating expenses, liquids gathering system operating lease expense, severance taxes, gathering costs, transportation charges, interest expense and general and administrative expenses divided by production on an Mcfe basis during the period.
- Cash operating costs — For any period, means the sum of lease operating expenses, liquids gathering system operating lease expense, severance taxes, gathering costs, transportation charges and general and administrative expenses divided by production on an Mcfe basis during the period.
- Reserve replacement ratio — The sum of the estimated net proved reserves added through extensions, discoveries, revisions and additions (including purchases of reserves) for a specified period of time divided by production for that same period of time.
- Finding and development costs — The sum of property acquisition costs, exploration costs and development costs for a specified period of time, divided by the total of proved reserve extensions, discoveries, revisions and additions (including purchases) for that same period of time.