Resolute Energy Corp
Form 10-K
March 12, 2018

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D. C. 20549

FORM 10-K

(Mark One)

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2017

OR

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE TRANSITION PERIOD FROM TO
Commission File No. 001-34464

RESOLUTE ENERGY CORPORATION

(Exact Name of Registrant as Specified in its Charter)

Delaware	27-0659371
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)
1700 Lincoln Street, Suite 2800	
Denver, CO	80203
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (303) 534-4600

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

Title of Each Class	Name of Exchange on Which Registered
Common Stock, par value $0.0001 per share	New York Stock Exchange

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

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. YES NO

Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act. YES NO

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

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files). YES NO

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§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	(Do not check if a smaller reporting company)	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 Exchange Act). Yes No

The aggregate market value of registrant's common stock held by non-affiliates on June 30, 2017, computed by reference to the price at which the common stock was last sold as posted on the New York Stock Exchange, was $629.0 million.

As of February 28, 2018, 23,066,559 shares of the Registrant's $0.0001 par value Common Stock were outstanding.

The following documents are incorporated by reference herein: Portions of the definitive Proxy Statement of Resolute Energy Corporation to be filed pursuant to Regulation 14A of the general rules and regulations under the Securities Exchange Act of 1934, as amended, for the 2018 annual meeting of stockholders ("Proxy Statement") are incorporated by reference into Part III of this Form 10-K.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains “forward-looking statements” as that term is defined in the Private Securities Litigation Reform Act of 1995. The use of any statements containing the “expect,” “estimate,” “project,” “budget,” “forecast,” “anticipate,” “intend,” “plan,” “may,” “will,” “could,” “should,” “poised,” “believes,” “predicts,” “potential,” “cont expressions are intended to identify such statements; however the absence of these words does not mean the statements are not forward-looking. Forward-looking statements included in this report relate to, among other things, anticipated production in 2018; anticipated gas to oil ratios in 2018; anticipated lease operating expense in 2018; anticipated general and administrative expense in 2018; our production and cost guidance for 2018; anticipated capital expenditures and activity in 2018; future leverage ratios; the impact and amount of contingency payments from the Aneth Field purchaser; potential proceeds from a midstream transaction with the Bronco properties; future earnout payments; future infrastructure and other capital projects; our financial condition and management of the Company in the current commodity price environment, including expectations regarding price fluctuations; future financial and operating results; liquidity and availability of capital; future borrowing base adjustments and the effect thereof; future pad drilling timing and plans and expected resulting cost savings and production impact; future production, reserve growth and decline rates; our plans and expectations regarding our development activities including drilling and completing wells, the number of such potential projects, locations and anticipated acreage held by production by the end of 2018; the potential impact of well interference and the effectiveness of operational adjustments to mitigate it; the prospectivity of our properties and acreage; the expected benefits of the Aneth Disposition (defined below); and the anticipated accounting treatment of various activities. Although we believe that these statements are based upon reasonable current assumptions, no assurance can be given that the future results covered by the forward-looking statements will be achieved. Forward-looking statements can be subject to risks, uncertainties and other factors that could cause actual results to differ materially from future results expressed or implied by the forward-looking statements. The forward-looking statements in this report are primarily, although not exclusively, located under the heading “Risk Factors.” All forward-looking statements speak only as of the date made. All subsequent written and oral forward-looking statements attributable to us, or persons acting on our behalf, are expressly qualified in their entirety by the cautionary statements. Except as required by law, we undertake no obligation to update any forward-looking statement. Factors that could cause actual results to differ materially from our expectations include, among others, those factors referenced in the “Risk Factors” section of this report and such things as:

- uncertainties regarding future actions that may be taken by Monarch Alternative Capital LP in furtherance of its nomination of director candidates for election at the Company’s 2018 annual meeting of stockholders;
- potential operational disruption caused by the actions of stockholder activists;
- the Company’s ability to successfully implement its strategy to create long-term stockholder value;
- volatility of oil and gas prices, including extended periods of depressed prices that would adversely affect our revenue, income, cash flow from operations and liquidity and the discovery, estimation and development of, and our ability to replace oil and gas reserves;
- a lack of available capital and financing, including the capital needed to pursue our operations and other development plans for our properties, on acceptable terms, including as a result of a reduction in the borrowing base under our revolving credit facility;
- our ability to achieve the growth and benefits we expect from our acquisitions;
- our ability to achieve the benefits we expect from the Aneth Disposition;
- the success of the development plan for and production from our oil and gas properties;
- the completion, timing and success of drilling on our properties;
- the potential for downspacing, infill or multi-lateral drilling in the Permain Basin or obstacles thereto;
- the completion and success of exploratory drilling on our properties;
- the timing and amount of future production of oil and gas;
- risks related to our level of indebtedness;
- our ability to fulfill our obligations under our revolving credit facility, the senior notes and any additional indebtedness we may incur;
-

constraints imposed on our business and operations by our revolving credit facility and senior notes which may limit our ability to execute our business strategy;

- future write downs of reserves and the carrying value of our oil and gas properties;
- acquisitions and other business opportunities (or lack thereof) that may be presented to and pursued by us, and the risk that any opportunity currently being pursued will fail to consummate or encounter material complications;
- risks associated with unanticipated liabilities assumed, or title, environmental or other problems resulting from, our acquisitions;
- our future cash flow, liquidity and financial position;
- the success of our business and financial strategy, derivative strategies and plans;

- risks associated with rising interest rates;
- inaccuracies in reserve estimates;
- operational problems, or uninsured or underinsured losses affecting our operations or financial results;
- the amount, nature and timing of our capital expenditures, including future development costs;
- the impact of any U.S. or global economic recession;
- the ability to sell or otherwise monetize assets at values and on terms that are advantageous to us;
- availability of, or delays related to, drilling, completion and production, personnel, supplies and equipment;
- risks and uncertainties in the application of available horizontal drilling and completion techniques;
- uncertainty surrounding occurrence and timing of identifying drilling locations and necessary capital to drill such locations;
- our ability to fund and develop our estimated proved undeveloped reserves;
- the effect of third party activities on our oil and gas operations, including our dependence on third party-owned water sourcing, gathering and disposal, oil gathering and gas gathering and processing systems;
- the concentration of our credit risk as the result of depending on one primary oil purchaser and one primary gas purchaser in the Delaware Basin;
- our operating costs and other expenses;
- our success in marketing oil and gas;
- the impact and costs related to compliance with, or changes in, laws or regulations governing our oil and gas operations and the potential for increased regulation of drilling and completion techniques, underground injection or fracing operations;
- our relationship with the local communities in the areas where we operate;
- the availability of water and our ability to adequately treat and dispose of water while and after drilling and completing wells;
- potential regulation of waste water injection intended to address seismic activity;
- the concentration of our producing properties in a single geographic area;
- potential changes to regulations affecting derivatives instruments;
- environmental liabilities under existing or future laws and regulations;
- the impact of climate change regulations on oil and gas production and demand;
- potential changes in income tax deductions and credits currently available to the oil and gas industry;
- the impact of weather and the occurrence of disasters, such as fires, explosions, floods and other events and natural disasters;
- competition in the oil and gas industry and failure to keep pace with technological development;
- actions, announcements and other developments in OPEC and in other oil and gas producing countries;
- risks relating to our joint interest partners' and other counterparties' inability to fulfill their contractual commitments;
- loss of senior management or key technical personnel;
- the impact of long-term incentive programs, including performance-based awards and stock appreciation rights;
- timing of issuance of permits and rights of way, including the effects of any government shut-downs;
- potential power disruptions or supply limitations in the electrical infrastructure serving our operations;
- timing of installation of gathering infrastructure in areas of new exploration and development;
- potential breakdown of equipment and machinery relating to the gathering and compression infrastructure;
- losses possible from pending or future litigation;
- cybersecurity risks;
- the risk of a transaction that could trigger a change of control under our debt agreements;
- risks related to our common stock, potential declines in stock prices and potential future dilution to stockholders;
- risk factors discussed or referenced in this report; and
- other factors, many of which are beyond our control.

Additionally, the Securities and Exchange Commission ("SEC") requires oil and gas companies, in filings made with the SEC, to disclose proved reserves, which are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, under existing economic conditions, operating methods and governmental regulations. The SEC permits the optional disclosure of probable and possible reserves. From time to time, we may elect to disclose "probable" reserves and "possible" reserves, excluding their valuation, in our SEC filings, press releases and investor presentations. The SEC defines "probable" reserves as "those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are likely as not to be recovered." The SEC defines "possible" reserves as "those additional reserves that are less certain to be recovered than probable reserves." The Company applies these definitions when estimating probable and possible reserves. Statements of reserves are only estimates and may not correspond to the ultimate quantities of oil and gas recovered. Any reserves estimates or potential resources disclosed in our public filings, press releases and investor presentations that are not specifically designated as being estimates of proved reserves may include estimated reserves not necessarily calculated in accordance with, or contemplated by, the SEC's reserves reporting guidelines.

SEC rules prohibit us from including resource estimates in our public filings with the SEC. Our potential resource estimates include estimates of hydrocarbon quantities for (i) new areas for which we do not have sufficient information to date to classify as proved, probable or possible reserves, (ii) other areas to take into account the level of certainty of recovery of the resources and (iii) uneconomic proved, probable or possible reserves. Potential resource estimates do not take into account the certainty of resource recovery and are therefore not indicative of the expected future recovery and should not be relied upon for such purpose. Potential resources might never be recovered and are contingent on exploration success, technical improvements in drilling access, commerciality and other factors. In our press releases and investor presentations, we sometimes include estimates of quantities of oil and gas using certain terms, such as "resource," "resource potential," "EUR," "oil in place," or other descriptions of volumes of reserves, which terms include quantities of oil and gas that may not meet the SEC definition of proved, probable and possible reserves. These estimates are by their nature more speculative than estimates of proved reserves and accordingly are subject to substantially greater risk of being recovered by Resolute. The Company believes its potential resource estimates are reasonable, but such estimates have not been reviewed by independent engineers. Furthermore, estimates of potential resources may change significantly as development provides additional data, and actual quantities that are ultimately recovered may differ substantially from prior estimates.

Production rates, including "early time" rates, 24-hour peak IP rates, 30-day peak IP rates, 90-day peak IP rates, 60-day peak IP rates, 120-day peak IP rates and 150-day peak IP rates for both our wells and for those wells that are located near to our properties are limited data points in each well's productive history and represent three stream gross production. These rates are sometimes actual rates and sometimes extrapolated or normalized rates. As such, the rates for a particular well may change as additional data becomes available. Peak production rates are not necessarily indicative or predictive of future production rates, EUR or economic rates of return from such wells and should not be relied upon for such purpose. Equally, the way we calculate and report peak IP rates and the methodologies employed by others may not be consistent, and thus the values reported may not be directly and meaningfully comparable. Lateral lengths described are indicative only. Actual completed lateral lengths depend on various considerations such as lease line offsets. Standard length laterals, sometimes referred to as 5,000 foot laterals, are laterals with completed length generally between 4,000 feet and 5,500 feet. Mid length laterals, sometimes referred to as 7,500 foot laterals, are laterals with completed length generally between 6,000 feet and 8,000 feet. Long laterals, sometimes referred to as 10,000 foot laterals, are laterals with completed length generally longer than 8,000 feet.

You are urged to consider closely the disclosure in this Annual Report on Form 10-K, in particular the factors described under "Risk Factors."

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Part I

ITEMS 1. and 2. BUSINESS and properties

As used in this Annual Report on Form 10-K, unless the context otherwise requires or indicates, references to “Resolute,” “the Company,” “we,” “our,” “ours,” and “us” refers to Resolute Energy Corporation and its subsidiaries.

Business Overview

Resolute Energy Corporation, a Delaware corporation incorporated on July 28, 2009, is a publicly traded, independent oil and gas company engaged in the exploitation, development, exploration for and acquisition of oil and gas properties with assets located in the Delaware Basin in west Texas (the “Permian Properties”, “Permian Basin Properties” or “Delaware Basin”). Our development activity is focused on our 27,100 gross (21,100 net) acres, approximately 90% of which is located in what we believe to be the core of the Wolfcamp horizontal play in northern Reeves County, Texas. Our corporate strategy is to drive organic growth in production, cash flow and reserves through development of our Reeves County acreage and to pursue opportunistic acquisitions in the Delaware Basin.

On November 6, 2017, Resolute closed on the disposition of our Aneth Field Properties located in the Paradox Basin in southeast Utah (the “Aneth Field Properties” or “Aneth Field”) (the “Aneth Disposition”) to an affiliate of Elk Petroleum Limited (“Elk”). The historical results of operations of the Aneth Field Properties prior to the disposition are contained in our financial position and results as of December 31, 2017, and for the twelve months ended December 31, 2017.

During 2017 oil sales comprised approximately 84% of revenue, and our December 31, 2017, estimated net proved reserves were approximately 53.4 million barrels of oil equivalent (“MMBoe”), of which approximately 49% were classified as proved developed producing reserves (“PDP”). Approximately 47% of our estimated net proved reserves were oil and approximately 70% were oil and natural gas liquids (“NGL”). The December 31, 2017, pre-tax present value discounted at 10% (“PV-10”) of our net proved reserves was $434 million and the standardized measure of our estimated net proved reserves was $433 million. For additional information about the calculation of our PV-10 and standardized measure, please read “Business and Properties — Estimated Net Proved Reserves.”

For 2017 the Board initially approved a capital expenditure plan primarily focused on a two rig drilling program spudding 22 gross wells in the Delaware Basin. This original capital program did not contemplate the Delaware Basin Bronco Acquisition or any related capital activities. Due to the continuing efficiency of our drilling and with the closing of the Aneth Disposition, our Board approved an expansion to our 2017 capital program, which allowed us to retain the rigs and completion crews that provided these excellent results. As a result of increased drilling and completion efficiency, Resolute was able to complete drilling operations on 25 wells and had three wells drilling over year-end, while still completing and bringing on line 21 wells in these areas. Excluding the three wells that were drilling over year-end, Resolute carried six drilled but uncompleted wells (“DUCs”) into 2018.

Resolute’s 2018 board-approved plan includes net capital spending of $365 million to $395 million, including $350 million to $375 million in drilling and completion capital to support two rigs throughout the year, and a third rig which commenced work in late February and is expected to be released in mid-September. Additionally, the Company expects to spend an incremental $42 million to $49 million on field facilities and other corporate capital, and to receive estimated earn-out payments of $27 million to $29 million from Caprock Permian Processing LLC and Caprock Field Services LLC (collectively “Caprock”). Overall, Resolute expects to drill 42 wells during the year and bring 38 wells on production, carry six DUCs and have two wells drilling over year-end 2018.

Each of the three rigs will be primarily pad drilling three-well stacks with all the rigs in the same spacing unit at the same time. Operations will focus in the Sandlot unit in Mustang and the Mitre/Ranger units in Appaloosa, with Wolfcamp Upper A, Lower A, and Upper B as the primary target zones. This approach to pad drilling will provide us with the opportunity to batch complete groups of up to nine wells simultaneously.

Beginning in late 2017 the Company shifted focus to building an inventory of drilled wells to batch complete. Two completions are expected in first quarter 2018, and in mid-March we will begin completing our first nine-well group. With the first nine-well group coming on line in May and another nine-well group coming on line in July we expect production growth to accelerate in the middle part of the year. Further groups of completed wells are expected to come on line throughout the remainder of the year.

This 2018 development plan was put in place based on the Company's experience with the impact of infill drilling on well performance. In estimating its 2018 total production, Resolute believes it has fully incorporated the anticipated effects of frac interference on older wells and the expected modestly reduced production from newly drilled infill wells. In addition the Company has taken into consideration potential operational events that could reduce production further such as power outages, weather, well shut-ins and downstream gas constraints.

On February 22, 2017, we closed on the sale of our Denton and South Knowles properties in the Northwest Shelf project area in Lea County, New Mexico, for approximately $14.5 million in cash, subject to customary purchase price adjustments. The proceeds of the sale were used for general corporate purposes. As part of the sale, the Company was also no longer liable for asset retirement obligations of $3.6 million at March 31, 2017.

On April 27, 2017, Resolute Natural Resources LLC ("Resolute Southwest") entered into a Crude Oil Connection and Dedication Agreement with Caprock Permian Crude LLC ("Caprock Crude"), an affiliate of Caprock. Pursuant to the agreement, Caprock Crude has constructed the gathering systems, pipelines and other infrastructure for the gathering of crude oil from our Mustang and Appaloosa operating areas in exchange for customary fees based on the volume of crude oil produced and delivered. Resolute Southwest has agreed to dedicate and deliver all crude oil produced from its acreage in Mustang and Appaloosa to Caprock Crude for gathering for a term through July 31, 2031, coterminous with our other commercial agreements with Caprock. For the first five years of the agreement, the crude oil will be delivered to Midland Station under a joint tariff arrangement between Caprock Crude and Plains Pipeline, L.P. On April 27, 2017, Resolute Southwest also entered into a Crude Oil Purchase Contract with Plains Marketing, L.P. ("Plains") providing for the sale to Plains of substantially all of the crude oil produced from the Mustang and Appaloosa areas for a price equal to an indexed market price less a $1.75 differential that will cover the joint tariff payable to Caprock Crude under the Crude Oil Connection and Dedication Agreement.

On May 15, 2017, Resolute Southwest closed on a Purchase and Sale Agreement with CP Exploration II, LLC and Petrocap CPX, LLC pursuant to which Resolute Southwest acquired certain producing and undeveloped oil and gas properties (the "Bronco Assets") in the Delaware Basin in Reeves County, Texas (the "Delaware Basin Bronco Acquisition"). The acquisition was accounted for as an asset acquisition. The Company acquired these properties for $161.3 million, which it financed substantially with proceeds received from the offering of $125 million of 8.50% Senior Notes due 2020 that closed in May 2017 (the "Incremental Senior Notes"). The properties acquired included approximately 4,600 net acres in Reeves County, Texas, which were considered predominantly unproved, consisting of 2,187 net acres adjacent to the Company's existing operating area in Reeves County and 2,400 net acres in southern Reeves County.

On November 6, 2017, to complete our repositioning as a pure-play Delaware Basin company, we completed the sale of our Aneth Field Properties. Total consideration will be up to $195 million, comprised of $160 million ($150 million of which was received at closing and $10 million of which was a deposit received in the third quarter 2017), adjusted for normal closing purchase price adjustments and up to an additional $35 million if oil prices exceed certain levels in the three years following the closing. The net proceeds of the Aneth Disposition were used to repay amounts outstanding under our Revolving Credit Facility and for other corporate purposes.

Business Strategies

The key elements of our business strategy include:

Organically Grow Production, Cash Flow and Reserves. Our primary business strategy is to generate growth in production, cash flow and reserves through organic development of the Wolfcamp formation in our Reeves County assets in the Delaware Basin. For 2018 our Board of Directors approved a drilling program drilling 42 gross wells with two and three rigs.

Pursue Acquisition Opportunities in Delaware Basin. We will continue to seek out attractive opportunities to expand our acreage and inventory of development locations through strategic acquisitions relying on our more than six year operating history in the Delaware Basin and our strong technical team to identify the best opportunities. The Delaware Basin Firewheel Acquisition and the Delaware Basin Bronco Acquisition represent examples of such opportunities.

Improve Corporate Profitability. We will continue to focus on improving the profitability of the Company through a multi pronged strategy, including, (a) improved unit operating costs resulting from cost control and increased production, (b) improved well economics as we continue to focus on drilling efficiencies, shift to infill drilling which leverages existing infrastructure and realize economies from a larger sustained drilling program, and (c) focus on improving overhead expenses per unit of production and optimizing efficiency within our corporate organization.

Manage Capital Structure. The execution of our 2018 operating plan is expected to lead to organic deleveraging of our balance sheet, as measured by the ratio of debt to Adjusted EBITDA. We will consider raising additional capital as required to fund accretive, high rate of return projects and attractive acquisition opportunities. We may also consider potential future issuances of equity to further delever our balance sheet if equity valuations are deemed favorable.

Competitive Strengths

We have a number of strengths that we believe will help us successfully execute our 2018 and longer term business strategies, including:

Multi year Portfolio of Significant Organic Drilling and Development Opportunities in One of the Premier U.S. Oil and Gas Producing Basins. We have a significant inventory of drilling and development locations in Reeves County, Texas, in what we believe to be the core of the Delaware Basin portion of the Permian Basin. This part of the Delaware Basin is a premier U.S. onshore oil and gas resource. We will move to full field development mode while continuing to drill wells across our acreage block and complete wells in multiple landing zones in the Wolfcamp A as well as in the Wolfcamp B and C.

Operational Staff with Deep Expertise. Our operating and technical staff has significant experience in the drilling, completing and operating of horizontal wells. This expertise has led to cost and production enhancements. The work of our operations team has led to reductions in drilling days and enhancements to our completion designs which we believe ultimately result in more productive and economic wells. During 2017, the Company set internal spud-to-TD records of 14 days drilling mid-length laterals in Mustang and 17 days drilling long laterals in Appaloosa.

Operating Control of Our Properties. Because we are the operator of substantially all of our properties we have the ability to more directly control the timing, scope and costs of our activity. Operatorship of our assets is secured for the foreseeable future, as approximately 89% of our core acreage in the Delaware Basin) (and 77% of our gross acreage) is held by production.

Summary Reserve Information

The following table presents summary information related to our estimated net proved reserves that are derived from our December 31, 2017, reserve report, which was prepared by Resolute and audited by Netherland, Sewell & Associates, Inc. ("NSAI"), independent petroleum engineers.

	Estimated Net Proved Reserves at December 31, 2017 (MMBoe)				
	Proved Developed Producing	Proved Developed Non-Producing	Proved Undeveloped	Total Proved	2017 Net Daily Production (Boe per day)
Permian Properties (Total)	26.0	0.2	27.2	53.4	20,112
Future operating costs ($ millions)				$512.3	
Future production taxes ($ millions)				116.8	
Future capital costs ($ millions)				285.4	

Description of Properties

Permian Basin Properties

As of December 31, 2017, we had interests in approximately 27,100 gross (21,100 net) acres in the Permian Basin of Texas. Our principal project area located in the Delaware Basin portion of the Permian Basin, in Reeves County, targets the Wolfcamp formation (the "Delaware Basin Wolfcamp Project"). Our development activity in the Delaware Basin Wolfcamp Project is focused on our 23,600 gross (18,700 net) acreage position. All 53.4 MMBoe of our proved reserves are associated with these assets as of December 31, 2017. During the year, we completed 31 gross (25.0 net) wells, which includes 6 DUCs and 4 non-operated wells, and had 81 gross (66.4 net) producing wells at year-end

2017. As of December 31, 2017, we were in the process of drilling 3 gross (3.0 net) wells and had 6 gross (5.8 net) wells awaiting completion operations. During 2017, average net daily production from the Permian Basin Properties was 20,112 equivalent barrels of oil ("Boe") and was 74% liquids. See "Business and Properties – Marketing and Customers" for more information on how production from this area is sold. Based on drilling activity to date, approximately 89% of the gross acreage is held by production. We are currently evaluating the 3,500 gross acres and 2,400 net acres we acquired in the Delaware Basin Bronco Acquisition in southern Reeves County for drilling opportunities in the Wolfcamp, Woodford and Barnett formations.

Acquisition of the Delaware Basin Bronco Properties. In May 2017, we acquired certain undeveloped and developed oil and gas properties in the Delaware Basin in Reeves County, Texas in the Delaware Basin Bronco Acquisition. The Company acquired these properties for $161.3 million, which it financed substantially with proceeds received from the offering of Incremental Senior Notes. The properties acquired include approximately 4,600 net acres in Reeves County, Texas, which were considered predominantly unproved, consisting of 2,187 net acres adjacent to the Company's existing operating area in Reeves County and 2,400 net acres in southern Reeves County.

Divestiture of Southeast New Mexico Properties in the Permian Basin. In February 2017 the Company closed on the sale of its Denton and South Knowles properties in the Northwest Shelf project area in Lea County, New Mexico, for approximately $14.5 million in cash, subject to customary purchase price adjustments. The proceeds of the sale were used for general corporate purposes.

Acquisition of Delaware Basin Firewheel Properties. In October 2016 we acquired certain Reeves County interests in the Delaware Basin, for consideration consisting of $90 million in cash and 2,114,523 shares of our common stock, issued to Firewheel Energy, LLC ("Firewheel") upon the closing of the purchase of the Firewheel properties (the "Firewheel Properties") in the Delaware Basin Firewheel Acquisition (the "Delaware Basin Firewheel Acquisition"). The cash paid for this acquisition was funded in part by net proceeds from the sale of preferred stock and borrowings on our Revolving Credit Facility.

Divestiture of Midstream Assets in the Delaware Basin. In July 2016 Resolute Southwest entered into a definitive Purchase and Sale Agreement (the "Mustang Agreement") with Caprock pursuant to which Resolute Southwest and an existing minority interest holder agreed to sell certain gas gathering and produced water handling and disposal systems owned by them in the Mustang project area in Reeves County, Texas, ("Mustang") for a cash payment of $35 million, plus certain earn-out payments described below.

In July 2016 Resolute Southwest also entered into a definitive Purchase and Sale Agreement (the "Appaloosa Agreement") with Caprock, pursuant to which Resolute Southwest agreed to sell certain gas gathering and produced water handling and disposal systems owned by Resolute Southwest in the Appaloosa project area in Reeves County, Texas, ("Appaloosa") for a cash payment of $15 million, plus certain earn-out payments described below.

In August 2016 Resolute Southwest closed the transactions contemplated by the Mustang Agreement and the Appaloosa Agreement. Resolute Southwest received aggregate consideration of approximately $36 million (including earn-out payments earned as of the closing).

In July 2016, in connection with the Appaloosa Agreement and the Mustang Agreement, Resolute Southwest also entered into a definitive Earn-out Agreement (the "Earn-out Agreement"), pursuant to which Resolute Southwest will be entitled to receive certain earn-out payments based on drilling and completion activity in Appaloosa and Mustang through 2020 that will deliver gas and produced water into the system. Earn-out payments for each qualifying well will vary depending on the lateral length of the well and the year in which the well is drilled and completed. In March 2017 the Earn-out Agreement was amended by the parties to provide for an increase in earn-out payments for the wells drilled and completed in 2017. Earn-out payments are contingent on future drilling, and therefore will be recognized when earned.

In connection with the closing of the transactions contemplated by the Appaloosa Agreement and the Mustang Agreement, Resolute Southwest entered into fifteen year commercial agreements with Caprock for gas gathering services and water handling and disposal services for all current and future gas and water produced by Resolute Southwest in Mustang and Appaloosa in exchange for customary fees based on the volume of gas and water produced and delivered. Resolute Southwest has agreed to dedicate and deliver all gas and water produced from its acreage in Mustang and Appaloosa to Caprock for gathering, processing, compression and disposal services for a term of fifteen years.

In April 2017, Resolute Southwest entered into a Crude Oil Connection and Dedication Agreement with Caprock Crude, an affiliate of Caprock. Pursuant to the agreement, Caprock Crude has constructed the gathering systems, pipelines and other infrastructure for the gathering of crude oil from our Mustang and Appaloosa operating areas in exchange for customary fees based on the volume of crude oil produced and delivered. Resolute Southwest has agreed to dedicate and deliver all crude oil produced from its acreage in Mustang and Appaloosa to Caprock Crude for gathering for a term through July 31, 2031, coterminous with our other commercial agreements with Caprock. For the first five years of the agreement, the crude oil will be delivered to Midland Station under a joint tariff arrangement between Caprock Crude and Plains Pipeline, L.P. In April 2017, Resolute Southwest also entered into a Crude Oil Purchase Contract with Plains providing for the sale to Plains of substantially all of the crude oil produced from the Mustang and Appaloosa areas for a price equal to an indexed market price less a $1.75 differential that will cover the joint tariff payable to Caprock Crude under the Crude Oil Connection and Dedication Agreement.

Divestiture of Properties in the Midland Basin. In December 2015 we sold our Gardendale properties in the Midland Basin in Midland and Ector Counties, Texas, for approximately $172 million. In May 2015 we sold our Howard and Martin County properties in the Permian Basin for approximately $42 million.

Divestiture of Aneth Field Properties

Aneth Field, a giant legacy oil field in southeast Utah, accounted for 20% of our production during 2017, averaging 4,974 Boe per day, of which 96% was oil.

In November 2017 we completed the sale of our Aneth Field Properties for total consideration of up to $195 million, comprised of $160 million received at closing, adjusted for normal closing purchase price adjustments, and up to an additional $35 million if oil prices exceed certain levels in the three years following the closing.

Divestiture of Wyoming Properties

In October 2015 we sold our Hilight Field interests in the Powder River Basin for approximately $55 million.

Estimated Net Proved Reserves

The following table presents our estimated net proved oil, gas and NGL reserves and the present value of our estimated net proved reserves as of December 31, 2017, 2016 and 2015 according to SEC standards. The standardized measure shown in the table below is not intended to represent the current market value of our estimated oil and gas reserves.

	Year Ended December 31,		
	2017	2016	2015
Net proved developed reserves			
Oil (MBbl)	12,274	30,026	25,672
Gas (MMcf)	46,827	24,209	7,098
NGL (MBbl)	6,136	3,595	1,019
MBoe (1)	26,215	37,656	27,874
Net proved undeveloped reserves			
Oil (MBbl)	13,045	13,778	3,076
Gas (MMcf)	47,987	28,238	6,761
NGL (MBbl)	6,173	4,127	1,043
MBoe (1)	27,215	22,611	5,246
Total net proved reserves			
Oil (MBbl)	25,319	43,804	28,747
Gas (MMcf)	94,814	52,448	13,859
NGL (MBbl)	12,309	7,722	2,063
MBoe (1)	53,430	60,267	33,120
PV-10 ($ in millions) (2)(3)	434	344	199
Discounted future income taxes ($ in millions)	(1)	—	—
Standardized measure ($ in millions) (2)(4)	433	344	199

(1) Boe is determined using one Bbl of oil or NGL to six Mcf of gas.

(2) In accordance with SEC and Financial Accounting Standards Board ("FASB") requirements, our estimated net proved reserves and standardized measure at December 31, 2017, 2016 and 2015, were determined utilizing prices equal to the twelve-month unweighted arithmetic average using first day of the month prices, resulting in an average Plains Marketing, L.P. posted WTI oil price of $47.79, $39.25 and $46.79 per Bbl and an average Platts Gas Daily El Paso Permian Basin spot gas price of $2.62, $2.31, and $2.45 per MMBtu for the Permian Properties,

respectively. Our estimated net proved reserves and standardized measure at December 31, 2016 and 2015 for the Aneth Properties, were determined utilizing prices equal to the respective twelve-month unweighted arithmetic average using the first day of the month prices, resulting in an average NYMEX WTI oil price of $42.75 and $50.28 per Bbl, and an average Platts Gas Daily El Paso San Juan Basin spot gas price of $2.33 and $2.46, respectively.

(3) PV-10 is a non-GAAP measure and incorporates all elements of the standardized measure, but excludes the effect of income taxes. Management believes that pre-tax cash flow amounts are useful for evaluative purposes since future income taxes, which are affected by a company's unique tax position and strategies, can make after-tax amounts less comparable.

(4) Standardized measure is the present value of estimated future net revenue to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC and FASB, less future development costs and production and income tax expenses, discounted at a 10% annual rate to reflect the timing of future net revenue. Calculation of standardized measure does not give effect to derivative transactions. For a description of our derivative transactions, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations —Quantitative and Qualitative Disclosures About Market Risk."

The data in the above table are estimates only. Oil and gas reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact way. Future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. The 10% discount factor used to calculate present value, which is required by SEC and FASB pronouncements, is not necessarily the most appropriate discount rate. The present value, no matter what discount rate is used, is materially affected by assumptions as to the timing of future production, among other factors, which may prove to be inaccurate. The accuracy of any reserves estimate is a function of the quality of available data and engineering and geological interpretation and judgment. Accordingly, reserves estimates may vary, perhaps significantly, from the quantities of oil and gas that are ultimately recovered.

As an operator of domestic oil and gas properties, we are required to file Department of Energy Form EIA-23, “Annual Survey of Oil and Gas Reserves,” as required by Public Law 93-275. There are differences between the reserves as reported on Form EIA-23 and as reported herein, largely attributable to the fact that Form EIA-23 requires that an operator report on the total reserves attributable to wells that it operates, without regard to level of ownership (i.e., reserves are reported on a gross operated basis, rather than on a net interest basis).

Producing oil and gas reservoirs are generally characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Therefore, without reserve additions in excess of production through successful exploitation and development activities or acquisitions, our reserves and production will ultimately decline over time. Please read “Risk Factors — Risks Related to Our Business, Operations and Industry” and “Note 13 — Supplemental Oil and Gas Information (unaudited)” to the audited consolidated financial statements for a discussion of the risks inherent in oil and gas estimates and for certain additional information concerning our estimated proved reserves.

Proved Developed and Undeveloped Reserves. Proved developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are proved reserves that are expected to be recovered from new wells drilled within five years into known reservoirs on undrilled acreage for which the existence and recoverability of such reserves can be estimated with reasonable certainty, or from existing wells on which a relatively major expenditure is required to establish production.

Our operated drilling focus in 2017 was to preserve term leasehold acreage in the Permian Basin Properties by drilling both proved and non-proved locations. During 2017, 19,871 net MBoe of proved developed reserves were added to the proved reserves base through a successful blend of both operated and non-operated drilling of 8 gross proved and 16 gross non-proved locations and through the addition of 2 gross producing wells and successful completion of 7 gross DUC locations, 6 operated and 1 non-operated, acquired in the Delaware Basin Bronco Acquisition. We acquired 362 MBoe net of proved developed producing reserves in the Delaware Basin Bronco Acquisition. An incremental 31 gross wells were drilled or completed in 2017 which yielded 19,509 MBoe net of proved developed reserves and 11,939 MBoe net of proved undeveloped reserves through the addition of 15 gross immediate offset proved undeveloped Permian locations. These numbers include 2,722 MBoe of net proved producing reserves and 1,387 MBoe of net proved undeveloped reserves attributable to successful completion of the Delaware Basin Bronco Acquisition DUC wellbores during 2017. The numbers above also include 2017 production of 3,958 net MBoe. An incremental 6,217 net MBoe of proved undeveloped reserves were also added to the proved reserves base during 2017 through the addition of 9 gross locations (6 operated and 3 non-operated) offset to wells drilled prior to 2017. The 9 gross locations were previously uneconomic at lower SEC pricing.

Included in the sale of our Aneth Field Properties in November 2017 were 371 gross (235.3 net) operated oil producing wells and their associated injection wells. Aneth Field accounted for approximately 41% of our total proved reserves at December 31, 2016, of which 99% was oil. In conjunction with the divestiture of Aneth Field, 18,033 MBoe net of total proved developed producing, 2,394 MBoe of net total proved developed non-producing and 2,169 MBoe net of proved undeveloped reserves were removed during 2017. These numbers are net of 2017 Aneth Field production of 1,816 net MBoe.

With respect to the properties included in our prior year reserve reports, we incurred development costs of $133.1 million in 2017 as compared to $31.1 million in 2016. The year over year change in developmental costs is also reflective of our operated drilling focus in 2017 to preserve term leasehold acreage in the Permian Basin. With respect to the total proved value, no proved undeveloped drilling locations are scheduled to be drilled after any corresponding portion of primary term leasehold within each is set to expire.

At December 31, 2017, no proved undeveloped reserves have remained, or are scheduled to remain, undeveloped beyond five years from the booking date.

Changes in Proved Reserves

Proved reserves reported by us at December 31, 2017, decreased from those reported at December 31, 2016, as follows:

	Oil Equivalent (MBoe)
Proved reserves as of December 31, 2016	60,267
Production	(9,156)
Extensions, discoveries and other additions	31,619
Purchases of minerals in place	362
Sales of minerals in place	(23,026)
Revisions of previous estimates	(6,636)
Proved reserves as of December 31, 2017	53,430
Proved developed reserves:	
As of December 31, 2017	26,215
Proved undeveloped reserves:	
As of December 31, 2017	27,215

Production consisted of 7,341 MBoe from the Permian properties during 2017 and 1,816 MBoe from the Aneth Field properties prior to their sale in November 2017.

Extensions, discoveries and other additions in 2017 consisted primarily of 10,741 MBoe net from 16 gross newly drilled Permian wells and 2,722 MBoe net from 7 gross completions of DUC locations acquired in the Delaware Basin Bronco Acquisition together with 11,939 MBoe net from 15 gross immediate offset proved undeveloped Permian locations. These numbers include 2,469 MBoe net of 2017 production. Also included in additions are 6,217 MBoe net of proved undeveloped reserves from 9 gross offset locations to Permian wells drilled prior to 2017 which were uneconomic under previous reports' SEC pricing.

Purchases of minerals in place consisted of 362 MBoe net from 2 gross producing wells acquired in the Delaware Basin Bronco Acquisition closed May 15, 2017.

Sales of minerals in place during 2017 consisted of 431 MBoe net from 36 gross producing wells in the Denton and Knowles South Fields New Mexico divestiture, which closed February 22, 2017, plus 22,595 MBoe net from 371 gross producing wells, and their associated injectors, in the Aneth Field Utah divestiture, which closed November 6, 2017. These numbers are net of 1,847 MBoe net of 2017 production, 32 MBoe net in Denton and Knowles South Fields, and 1,816 MBoe net in Aneth Field.

Revisions of previous estimates of 6,636 MBoe during 2017 were a function of well performance resulting from interference between existing, mature producers and newly drilled wells. The 2018 development plan has been designed to minimize further such interference.

Controls Over Reserve Report Preparation, Technical Qualification and Methodologies Used

Reserve estimates as of December 31, 2017, were prepared by Resolute and audited by Netherland, Sewell & Associates, Inc. (“NSAI”), our independent petroleum engineers. Please read “Risk Factors — Risks Related to Our Business, Operations and Industry” in evaluating the material presented below.

Our reserve report was prepared under the direct supervision of the Company’s Corporate Reserves Manager, Mr. Michael White. Mr. White has more than 33 years of experience in the oil and gas industry including general reservoir engineering, corporate engineering, exploration support and economic analysis support. During his career, Mr. White has resided and worked in Texas, Louisiana, Florida and Colorado. Additionally, he has performed evaluations in other basins in Utah, Wyoming, North Dakota and Washington state. He has onshore, shallow water and deep water project experience. Mr. White has a Bachelor of Science degree in Petroleum Engineering from Mississippi State University (1984) and a Masters of Business Administration from the University of Houston (1997). He is registered as a Professional Engineer in the states of Colorado, Texas and Wyoming. His qualifications meet or exceed the qualifications of reserve estimators and auditors as set forth in the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers. Mr. White is a member of the Society of Petroleum Engineers and Society of Petroleum Evaluation Engineers.

The reserve report is based upon a review of property interests being appraised, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, geoscience and engineering data, and other information as prescribed by the SEC. The reserve estimates are reviewed internally by Resolute's senior management prior to an audit of the reserve estimates by NSAI. A variety of methodologies are used to determine our proved reserve estimates. The principal methodologies employed are decline curve analysis, advanced production type curve matching, volumetrics, material balance, petrophysics/log analysis and analogy reservoir simulation. Some combination of these methods is used to determine reserve estimates in substantially all of our areas of operation.

The reserves estimates shown herein have been independently audited 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 person primarily responsible for auditing the estimates set forth in the NSAI reserves audit letter incorporated herein is Mr. Joseph J. Spellman. Mr. Spellman, a Licensed Professional Engineer in the State of Texas (No. 73709), has been practicing consulting petroleum engineering at NSAI since 1989 and has more than nine years of prior industry experience. He graduated from University of Wisconsin-Platteville in 1980 with a Bachelor of Science Degree in Civil Engineering. Mr. Spellman meets or exceeds 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. He is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

A report of NSAI regarding its audit of the estimates of proved reserves at December 31, 2017, has been filed as Exhibit 99.1 to this report and is incorporated herein.

Production, Price and Cost History

The table below summarizes our operating data for 2017, 2016 and 2015.

	Year Ended December 31,		
	2017	2016	2015
Sales Data:			
Oil (MBbl)	5,499	3,821	3,271
Gas (MMcf)	12,101	4,811	5,194
NGL (MBbl)	1,640	559	400
Combined volumes (MBoe)	9,156	5,182	4,535
Daily combined volumes (Boe per day)	25,086	14,157	12,427
Average Realized Prices (excluding derivative settlements):			
Oil ($/Bbl)	$46.30	$38.83	$42.16
Gas ($/Mcf)	2.11	2.22	2.43
NGL ($/Bbl)	14.20	9.80	10.32
Average Production Costs ($/Boe):			
Lease operating expense	$8.66	$12.29	$17.50
Production and ad valorem taxes	2.55	3.14	4.41

Total estimated proved reserves attributed to the Delaware Basin exceeded fifteen percent of our total proved reserves expressed on an equivalent basis. The Delaware Basin area consists of mineral interests in the Wolfcamp formation. Due to the disposition of Aneth Field in November 2017, the Aneth proved reserve value would not exceed the fifteen percent threshold for disclosure. Therefore, the table below summarizes our operating data for the Delaware Basin for 2017, 2016 and 2015.

Delaware Basin:

	Year Ended December 31,		
	2017	2016	2015
Sales Data:			
Oil (MBbl)	3,765	1,489	393
Gas (MMcf)	11,612	3,989	1,579
NGL (MBbl)	1,641	549	224
Combined volumes (MBoe)	7,341	2,704	880
Daily combined volumes (Boe per day)	20,112	7,387	2,412
Average Realized Prices (excluding derivative settlements):			
Oil ($/Bbl)	$48.08	$42.25	$43.50
Gas ($/Mcf)	2.13	2.40	2.29
NGL ($/Bbl)	14.20	9.64	7.89
Average Production Costs ($/Boe):			
Lease operating expense	$5.46	$4.62	$7.47
Production and ad valorem taxes	1.94	2.14	2.67

Oil and Gas Wells

The following table sets forth information as of December 31, 2017, relating to the productive wells in which we own a working interest. A well with multiple completions in the same bore hole is considered one well. Wells are considered oil or gas wells according to the predominant production stream, except that a well with multiple completions is considered an oil well if one or more is an oil completion. Productive wells consist of producing wells and wells capable of producing, including wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we have a working interest and net wells are the sum of our working interests owned in gross wells.

	Productive Wells[(1)]	
	Gross	Net
Oil	80	66.3
Gas	1	0.1
Total	81	66.4

(1) We operated 69 gross (64.3 net) productive wells at December 31, 2017.

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Drilling Activity

The following table sets forth information with respect to exploration, development and extension wells we completed during 2017, 2016 and 2015. The number of gross wells is the total number of wells we participated in, regardless of our ownership interest in the wells. An extension well is a well drilled to extend the limits of a known reservoir. Fluid injection wells for waterflood and other enhanced recovery projects are not included as gross or net wells.

	Year Ended December 31,		
	2017	2016	2015
Gross exploration wells:			
Productive [1]	—	—	—
Dry [2]	—	—	—
Total exploration wells	—	—	—
Gross development wells:			
Productive [1]	8	—	1
Dry [2]	—	—	—
Total development wells	8	—	1
Gross extension wells:			
Productive [1][3]	23	14	5
Dry [2]	—	—	—
Total extension wells	23	14	5
Total gross wells drilled	31	14	6

	Year Ended December 31,		
	2017	2016	2015
Net exploration wells:			
Productive [1]	—	—	—
Dry [2]	—	—	—
Total exploration wells	—	—	—
Net development wells:			
Productive [1]	7.7	—	0.7
Dry [2]	—	—	—
Total development wells	7.7	—	0.7
Net extension wells:			
Productive [1][3]	17.3	12.0	1.5
Dry [2]	—	—	—
Total extension wells	17.3	12.0	1.5
Total net wells drilled	25.0	12.0	2.2

(1) A productive well is a well we have cased. Wells classified as productive do not always result in wells that provide economic production.
(2) A dry well is a well that is incapable of producing oil or gas in sufficient quantities to justify completion.
(3) An extension well is a well drilled to extend the limits of a known reservoir.
(4) Included in the 2015 count is 1 gross (0.1 net) productive extension well sold to Qstar, LLC in May 2015.

Acreage

All of our leasehold acreage is categorized as developed or undeveloped. The following table sets forth information as of December 31, 2017, relating to our leasehold acreage.

	Developed Acreage (1)	
Area	Gross (2)	Net (3)
Permian Basin (TX)	19,010	15,608
North Dakota	516	99
Total	19,526	15,707

	Undeveloped Acreage (4)	
Area	Gross (2)	Net (3)
Permian Basin (TX)	8,048	5,472
Total	8,048	5,472

(1) Developed acreage is acreage attributable to wells that are capable of producing oil or gas.
(2) The number of gross acres is the total number of acres in which we own a working interest and/or unitized interest.
(3) Net acres are calculated as the sum of our working interests in gross acres.
(4) Undeveloped acreage includes leases either within their primary term or held by production.

Approximately 900 net acres, 2,200 net acres and 1,000 net acres of undeveloped acreage will revert or expire in 2018, 2019 and 2020, respectively, absent activity to develop such acreage or exercising extension options.

Present Activities

As of December 31, 2017, we were in the process of drilling 3 gross (3.0 net) wells and there were 6 gross (5.8 net) wells waiting on completion operations. Please read “Business and Properties – Descriptions of Properties” for additional discussion regarding our present activities.

Marketing and Customers

Crude Oil Sales

Materially all of our crude oil produced from the Mustang and Appaloosa areas is sold via pipe to Plains under a contract that extends through May 1, 2022. Crude oil produced from our Bronco acreage is sold to Enterprise Crude Oil, LLC under a month-to-month contract with a 30-day cancellation provision.

Gas and NGL Sales

Our gas and NGL from the Mustang and Appaloosa areas are sold to Energy Transfer Partners, L.P. under a fee-based contract that expires December 31, 2018. Gas and NGL produced from the Bronco acreage are sold to Delaware Basin Midstream through ConocoPhillips under a fee-based agreement with a primary term extending until June 30, 2018, and month-to-month thereafter.

Other Factors

The market for our production depends on factors beyond our control, including domestic and foreign political conditions, the overall level of supply of and demand for oil and gas, the price of imports of oil and gas, weather conditions, the price and availability of alternative fuels, the proximity and capacity of transportation facilities and overall economic conditions. The oil and gas industry as a whole also competes with other industries in supplying the energy and fuel requirements of industrial, commercial and individual consumers.

Derivatives

We enter into derivative transactions from time to time with unaffiliated third parties for portions of our oil and gas production to achieve more predictable cash flows and to reduce exposure to short-term fluctuations in oil and gas prices. For a more detailed discussion, please read –"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Title to Properties

Producing Property Acquisitions

We believe we have satisfactory title to all of our material proved properties in accordance with standards generally accepted in the industry. Prior to completing an acquisition of proved hydrocarbon leases we perform title reviews on the most significant leases, and, depending on the materiality of properties, we may obtain a new title opinion or review previously obtained title opinions.

Non-Producing Leasehold Acquisitions

We participate in the normal industry practice of engaging consulting companies to research public records before making payment to a mineral owner for non-producing leasehold. Prior to drilling a well on these properties, a title attorney is engaged to give an opinion of title.

Our properties are also subject to certain other encumbrances, such as customary interests generally retained in connection with the acquisition of real property, customary royalty interests and contract terms and restrictions, liens under operating agreements, liens for current taxes and other burdens, easements, restrictions and minor encumbrances customary in the oil and gas industry. We believe that none of these liens, restrictions, easements, burdens and encumbrances will materially detract from the value of these properties or from our interest in these properties or will materially interfere with the intended operation of our business.

Competition

Competition is intense in all areas of the oil and gas industry. Major and independent oil and gas companies actively seek to hire qualified employees and bid for desirable properties, as well as for the equipment and labor required to operate and develop such properties. Many of our competitors have financial and personnel resources that are substantially greater than our own and such companies may be able to pay more for productive properties and to define, evaluate, bid for and purchase a greater number of properties than our financial or human resources permit. Our ability to acquire additional properties and to discover reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment.

Seasonality

Our operations have not historically been subject to seasonality in any material respect although they may be affected by extreme weather.

Environmental, Health and Safety Matters and Regulation

General. We are subject to various stringent and complex federal, state and local laws and regulations governing environmental protection, including the discharge of materials into the environment, and protection of human health and safety. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling commences or other operations are undertaken;
- require the installation and operation of expensive pollution control equipment;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and gas drilling, production, transportation and processing activities;
- suspend, limit or prohibit construction, drilling and other activities in certain lands lying within wilderness, wetlands and other protected areas;
- require remedial measures to mitigate pollution from historical and ongoing operations, such as the closure of pits and plugging of abandoned wells, and the remediation of releases of oil or other substances; and

- require preparation of an Environmental Assessment and/or an Environmental Impact Statement.

The regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability.

Governmental authorities have the power to enforce compliance with environmental laws, regulations and permits, and violations are subject to injunctive action, as well as administrative, civil and criminal penalties. Furthermore, regulatory and overall public scrutiny focused on the oil and gas industry is increasing significantly. The effects of these laws and regulations, as well as other laws or regulations that may be adopted in the future, could have a material adverse impact on our business, financial condition and results of operations.

We believe our operations are in substantial compliance with all existing environmental, health and safety laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations. Spills, unpermitted releases or other deviations from applicable requirements may occur in the course of our operations. There can be no assurance that we will not incur substantial costs and liabilities as a result of such spills, unpermitted releases or deviations, including those relating to claims for damage to property, persons and the environment, nor can there be any assurance that the passage of more stringent laws or regulations in the future will not have a negative effect on our business, financial condition, or results of operations.

The following is a summary of the more significant existing environmental, health and safety laws and regulations to which oil and gas business operations are generally subject and with which compliance may have a material adverse effect on our capital expenditures, earnings or competitive position, as well as a discussion of certain matters that specifically affect our operations.

Comprehensive Environmental Response, Compensation, and Liability Act. CERCLA, also known as the “Superfund law,” and comparable state laws may impose strict, joint and several liability, without regard to fault, on classes of persons who are considered to be responsible for the release or threat of release of CERCLA “hazardous substances” into the environment. These persons include the current and former owners and operators of the site where a release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances released into the environment. Such claims may be filed under CERCLA, as well as state common law theories or state laws that are modeled after CERCLA. In the course of our operations, we handle materials and generate waste that may fall within CERCLA’s definition of hazardous substances. Therefore, governmental agencies or third parties could seek to hold us responsible for all or part of the costs to clean up a site at which such hazardous substances may have been released or deposited, or other damages resulting from a release.

Waste Handling. The Resource Conservation and Recovery Act (“RCRA”) and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of solid and hazardous wastes. Under the auspices of the federal EPA, the individual states may administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters and many of the other wastes associated with the exploration, development and production of oil or gas are currently exempt under federal law from regulation as RCRA hazardous wastes and instead are regulated as non-hazardous solid wastes. It is possible, however, that oil and gas exploration and production wastes now classified federally as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our operating expenses, which could have a material adverse effect on the results of operations and financial position. Also, in the course of operations, we generate some amounts of industrial wastes, such as paint wastes, waste solvents, and waste oils, which may be regulated as hazardous wastes under RCRA and state laws and regulations.

Air Emissions. The federal Clean Air Act and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. These regulatory programs may require us to install and operate expensive emissions control equipment, modify our operational practices and obtain permits for existing operations. Before commencing construction on a new or modified source of air emissions, these laws may require us to reduce our emissions at existing facilities. As a result, we may be required to incur increased capital and operating costs. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated federal and state laws and regulations.

In August 2012, the EPA published final rules that established new air emission control requirements for oil and natural gas production and natural gas processing operations. Specifically, the EPA's rule package included New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds ("VOCs"), and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The rules established specific new requirements regarding emissions from compressors, dehydrators, storage tanks and other production equipment as well as more stringent leak detection requirements for natural gas processing plants. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, as well as court challenges to the rules, and in 2013 issued revised rules that were responsive to some industry concerns. In December 2014, the EPA issued still further final revisions in response to stakeholder petitions for reconsideration of various regulatory provisions. In June 2016 EPA published final amendments to the 2012 NSPS Subpart OOOO rules as well as new final rules focused on achieving additional methane and volatile organic compound reductions from the oil and natural gas industry. The new final rules in NSPS Subpart OOOOa impose requirements for leak detection and repair ("LDAR"), control requirements at hydraulically fractured oil well completions, replacement of certain pneumatic pumps and controllers, and additional control requirements for gathering, boosting, and compressor stations, among other things. These final revised and new rules issued in 2013, 2014 and 2016 require modifications to our operations as promulgated, increasing our capital and operating costs. In June 2017, the EPA published a proposed rule to stay for 2 years certain provisions of the final rules in NSPS Subpart OOOOa, including the LDAR requirements; however, at this time, the rule remains in effect. Actual air emissions reported for our facilities are in material compliance with the terms of existing air permits and the emissions limits contained in the pending permit applications.

Water Discharges. The Federal Water Pollution Control Act, or the Clean Water Act, and analogous state laws, impose restrictions and strict controls on the discharge of "pollutants" into waters of the United States, including wetlands, without appropriate permits. Pollutants under the Clean Water Act, are defined to include produced water and sand, drilling fluids, drill cuttings, dredge and fill material, and other substances related to the oil and gas industry. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for unauthorized discharges or noncompliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. They also can impose substantial liability for the costs of removal or remediation associated with discharges of oil, hazardous substances or other pollutants.

The Clean Water Act also regulates stormwater discharges from industrial properties and construction sites, and requires separate permits and implementation of a Stormwater Pollution Prevention Plan ("SWPPP") establishing best management practices, training, and periodic monitoring of covered activities. Certain operations also are required to develop and implement Spill Prevention, Control, and Countermeasure ("SPCC") plans or facility response plans to address potential oil spills.

In September 2013, the EPA and U.S. Army Corps of Engineers released a Connectivity Report that determined that virtually all tributary streams, wetlands, open water in floodplains and riparian areas are connected. In June 2015, the U.S. Army Corps of Engineers issued a final rule clarifying the definition of "Waters of the United States". The rule expanded, in a number of ways, the scope of activities subject to Clean Water Act permitting. This rule, known as the Clean Water Rule, was challenged by various parties in multiple federal courts, and as a result of this litigation is currently stayed. In July 2017, the EPA and U.S. Army Corps of Engineers issued a Notice of Intention to review and rescind or revise the Clean Water Rule, and in November 2017, the agencies issued a proposed rule delaying the effective date of the Clean Water Rule for 2 years to allow for such review.

In addition, the Oil Pollution Act of 1990, or OPA, augments the Clean Water Act and imposes strict liability for owners and operators of facilities that are the source of a release of oil into waters of the United States. OPA and its associated regulations impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills. For example, certain operators of oil and gas facilities must develop, implement, and maintain facility response plans, conduct annual spill training for employees and provide varying degrees of financial assurance to cover costs that could be incurred in responding to oil spills. In addition, owners and operators of oil and gas facilities may be subject to liability for cleanup costs and natural resource damages as well as a variety of public and private damages that may result from oil spills.

Environmental Impact Assessments. Significant federal decisions, such as the issuance of federal permits or authorizations for many oil and gas exploration and production activities are subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the Department of Interior, to evaluate major federal agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment of the potential direct, indirect and cumulative impacts of a proposed project and/or, will prepare a more detailed Environmental Impact Statement that is made available for public review and comment. Any exploration and production activities on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay such oil and gas development projects.

Other Laws and Regulations

Climate Change. Recent scientific studies have suggested that human-caused emissions of gases commonly referred to as "greenhouse gases" or "GHGs", including CO_2, nitrogen dioxide and methane, are contributing to warming of the Earth's atmosphere, or climate change. Many other nations already have agreed to regulate their emissions of GHGs pursuant to the United Nations Framework Convention on Climate Change, ("UNFCCC") and the Kyoto Protocol, an international treaty (not including the United States) pursuant to which many UNFCCC member countries agreed to reduce their emissions of GHGs to below 1990 levels by 2012, with a subsequent emissions reduction commitment for the period from 2013 through 2020. Although a successor treaty to the Kyoto Protocol has not been developed to date, further GHG regulation may result from the December 2015 agreement reached at the United Nations climate change conference in Paris (the Paris Agreement). Pursuant to the Paris Agreement, the United States made an initial pledge to a 26-28% reduction in its GHG emission by 2025 against a 2005 baseline and committed to periodically update its pledge in five-year intervals starting in 2020. In response to such studies and international action, the U.S. Congress has considered but not passed legislation to reduce emissions of GHGs; however, as a result of the U.S. Supreme Court's decision on April 2, 2007, in Massachusetts. v. EPA, the EPA has taken steps to regulate GHG emissions from mobile sources (e.g., cars and trucks) even though Congress has not enacted new legislation specifically addressing GHG emissions. The Court's holding in Massachusetts v. EPA that GHGs fall under the federal Clean Air Act's definition of "air pollutant" has also resulted in the regulation and permitting of GHG emissions from major stationary sources under the Clean Air Act, due to EPA's "endangerment finding" that links global warming to human-caused emissions of GHG, and the EPA's subsequent GHG Tailoring Rule, which subjects certain major sources of GHG emissions to Title V operating permit and New Source Review permitting requirements for the first time. The permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration and Title V permitting programs will require affected facilities to meet emissions limits that are based on "best available control technology," which will be established by the permitting agencies on a case-by-case basis. In July 2012, the GHG Tailoring Rule became effective for all new facilities that emit at least 100,000 tons of GHG per year, but the rule was challenged in federal court on various legal grounds. In June 2014, the United States Supreme Court's holding in Utility Air Regulatory Group v. EPA upheld a portion of EPA's GHG stationary source permitting program, but also invalidated a portion of it. Upon remand, the EPA is considering how to implement the Court's decision. The Court's holding does not prevent states from considering and adopting state-only major source permitting requirements based solely on GHG emission levels. Additionally, the EPA promulgated a mandatory GHG reporting rule that took effect January 1, 2010. The mandatory reporting rule (MRR) and subsequent amendments included reporting requirements for operators that emit more than 25,000 metric tons of CO_2-equivalent GHG across an entire producing basin. On November 13, 2014, the EPA finalized additional portions of the MRR. The new provisions went into effect on January 1, 2015, and included revised monitoring and data disclosure requirements for the petroleum and natural gas industry clarifying that the engines, boilers, heaters, flares, and separation and processing equipment are among the emission sources that must provide greenhouse gas reports. In addition, the EPA also issued a final rule on October 22, 2015 that expanded the types of sources that are covered by the MRR. These sources include oil well completions and workovers with hydraulic fracturing, petroleum and natural gas gathering and boosting systems, and transmission pipeline blowdowns between compressor stations. Currently, Resolute's Permian Basin operations are subject to the MRR requirements. A number of states also have taken legal measures to reduce emissions of GHG, primarily through the planned development of GHG emission inventories and/or regional cap-and-trade programs, but we do not currently conduct business in those states. The passage or adoption of additional legislation or regulations that restrict emissions of GHG or require reporting of such emissions in areas where we conduct business could adversely affect our operations.

In addition, former President Obama released a Strategy to Reduce Methane Emissions in March 2014. Consistent with that strategy, the EPA issued a final rule in 2016 that set additional standards for methane and volatile organic compound emissions from oil and gas production sources, including hydraulically fractured oil wells and natural gas processing and transmission sources. As noted above, certain provisions of the new final rules in NSPS Subpart

OOOOa are the subject of a proposed two-year stay, although the rules remain effective. In addition, the Federal Bureau of Land Management (BLM) has finalized standards for reducing venting and flaring on public lands. The final rule was published in the Federal Register in November 2016. The final rule is the subject of pending litigation in the District of Wyoming federal court by industry members and certain states seeking to overturn the rule in part. Although the court denied a request for preliminary injunction to prevent the rule from taking effect in January 2017, the District of Wyoming litigation is ongoing. In addition to the Wyoming litigation, there was litigation over a proposed stay of the rule in the Norther District of California. The 2016 final rule included two different categories of requirements and implementation deadlines one set 2017 and one in 2018. The 2017 requirements that included, among others, a "waste minimization plan," are still in effect and implementation is ongoing. In December 2017, the BLM published a final rule suspending the remaining 2018 requirements for two years. Continued litigation and/or updates to the rule are expected. In the courts, several decisions have been issued that may increase the risk of claims being filed by governments and private parties against companies that have significant GHG emissions. Such cases may seek to challenge air emissions permits that GHG emitters apply for and seek to force emitters to reduce their emissions or seek damages for alleged climate change impacts to the environment, people, and property.

Any laws or regulations that may be adopted to restrict or reduce emissions of GHGs could require us to incur additional operating costs, such as costs to purchase and operate emissions control systems or other compliance costs, and could reduce demand for our products.

Department of Homeland Security. The Department of Homeland Security Appropriations Act of 2007 requires the Department of Homeland Security ("DHS") to issue regulations establishing risk-based performance standards for the security at chemical and industrial facilities, including oil and gas facilities that are deemed to present "high levels of security risk." The DHS is in the process of adopting regulations that will determine whether some of our facilities or operations will be subject to additional DHS-mandated security requirements. Under this authority, in April 2007, the DHS promulgated the Chemical Facilities Anti-Terrorism Standards ("CFATS") regulations. Facilities that possessed any chemical on the CFATS Appendix A: DHS Chemicals of Interest List at or above the listed Screening Threshold Quantity for each chemical on the day Appendix A was published (November 2007) are subject to CFATS regulation. We are currently not aware of any affected Company facilities subject to the CFATS regulations.

Occupational Safety and Health Act. We are subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes that strictly govern protection of the health and safety of workers. The Occupational Safety and Health Administration's hazard communication standard and Process Safety Management ("PSM") regulations, the Emergency Planning and Community Right-to-Know Act, and similar state statutes require that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities, and the public. PSM requirements applicable to gas processing activities are an intended focus of OSHA enforcement in recent years, and emphasize the need for process safety information disclosure, including short- and long-term off-site consequence analyses. We believe that we are in substantial compliance with applicable requirements of these and other OSHA and comparable state health and safety requirements.

Significant Changes to U.S. Federal Income Tax Laws. On December 22, 2017, President Trump signed Public Law No. 115-97, commonly referred to as the "Tax Cuts and Jobs Act" (the "Tax Act"). The Tax Act makes significant changes to the U.S. federal income taxation of individuals and corporations, generally effective for taxable years beginning on or after January 1, 2018. Among the changes to U.S. federal income tax laws, the Tax Act: (1) permanently replaces the progressive corporate income tax rate structure with a flat corporate income tax rate of 21%, (2) limits the current deductibility of net business interest expense to 30% of the Company's "adjusted taxable income" (as defined in the Tax Act), (3) limits the utilization of net operating losses ("NOLs") generated in taxable years beginning after December 31, 2017 to 80% of taxable income and repeals the rule allowing for carryback of such NOLs to offset taxable income in prior taxable years, (4) permits the unlimited carryforward of NOLs generated in taxable years beginning after December 31, 2017, (5) temporarily permits 100% expensing of certain business assets, (6) permanently repeals the deduction for domestic production activities, (7) permanently repeals the corporate alternative minimum tax ("corporate AMT"), which favorably impacts the deductibility of intangible drilling costs, (8) places additional limitations on certain general and administrative expenses, and (9) changes executive compensation rules.

In accordance with ASC 740, Accounting for Income Taxes, companies are required to recognize the effect of tax law changes in the period of enactment. Adjustments to our tax provision that were recorded in the three months ended December 31, 2017 principally relate to the reduction in the U.S. corporate income tax rate from a maximum 35% rate to a flat 21% rate, which resulted in the Company remeasuring its deferred tax assets and associated valuation allowance on those deferred tax assets, that will reverse at the new 21% flat rate. In addition, the repeal of the corporate AMT has resulted in the Company recognizing a current tax benefit of $0.3 million related to newly refundable AMT credits.

Currently, we do not anticipate paying cash federal income taxes in the near term due to any of the federal income tax law changes enacted by the Tax Act, primarily due to our ability to expense intangible drilling costs and the utilization of our pre January 1, 2018 NOL carryforwards which can be utilized to offset 100% of taxable income. Based on the

Company's current interpretation and subject to the release of regulations promulgated by the U.S. Department of Treasury ("Treasury Regulations") and any other future interpretive guidance relating to the Tax Act, the Company believes the effects of the change in U.S. federal income tax laws incorporated herein are substantially complete.

Other Regulation of the Oil and Gas Industry

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

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

- the location of wells;
- the method of drilling and casing wells;
- the rates of production or “allowables”;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells;
- the underground injection of salt water; and
- notice to surface owners and other third-parties.

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

Gas Sales and Transportation. Historically, federal legislation and regulatory controls have affected the price of gas and the manner in which our production is marketed. Federal Energy Regulatory Commission (“FERC”) has jurisdiction over the transportation and sale for resale of gas in interstate commerce by gas companies under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Since 1978, various federal laws have been enacted which have resulted in the complete removal of all price and non-price controls for sales of domestic gas sold in “first sales,” which include all of our sales of our own production.

FERC also regulates interstate gas transportation rates and service conditions, which affects the marketing of gas that we produce, as well as the revenue we receive for sales of our gas. Commencing in 1985, FERC promulgated a series of orders, regulations and rule makings that significantly fostered competition in the business of transporting and marketing gas. Today, interstate pipeline companies are required to provide nondiscriminatory transportation services to producers, marketers and other shippers, regardless of whether such shippers are affiliated with an interstate pipeline company. FERC’s initiatives have led to the development of a competitive, unregulated, open access market for gas purchases and sales that permits all purchasers of gas to buy gas directly from third-party sellers other than pipelines. However, the gas industry historically has been very heavily regulated; therefore, we cannot guarantee that the less stringent regulatory approach, recently pursued by FERC and Congress, will continue indefinitely into the future nor can it determine what effect, if any, future regulatory changes might have on gas related activities.

Under FERC’s current regulatory regime, transmission services must be provided on an open-access, non-discriminatory basis at cost-based rates or at market-based rates if the transportation market at issue is sufficiently competitive. Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states on-shore and in-state waters. Although its policy is still in flux, FERC recently has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of getting gas to point-of-sale locations.

Hydraulic Fracturing Disclosure and Possible Regulation or Prohibition. Hydraulic fracturing or “fracing” is a process used by oil and gas producers in the completion or re-working of some oil and gas wells. Water, sand and certain chemical additives are injected under high pressure into subsurface formations to create and prop open fractures in the rock and thus enable fluids that would otherwise remain trapped in the formation to flow to the surface. Fracing has been in use for many years in a variety of geologic formations. Combined with advances in drilling technology, recent advances in fracing technology have contributed to a large increase in production of gas and oil from shales that would otherwise not be economically productive. Fracing is typically subject to state oil and gas agencies' regulatory oversight, and has not been regulated at the federal level. However, due to assertions that fracing may adversely affect drinking water supplies, the federal EPA has released a final report on the potentially adverse impacts that fracing may have on water quality and public health, and in April 2015, the EPA proposed regulations under the Clean Water Act to impose pretreatment standards on wastewater discharges associated with hydraulic fracturing activities. In December 2016, the EPA released its final report on the potential impacts to drinking water resources from hydraulic fracturing, which concludes that hydraulic fracturing activities can impact drinking water resources under some circumstances.

Also, EPA has initiated a stakeholder and potential rulemaking process under the Toxic Substances Control Act ("TSCA") to obtain data on chemical substances and mixtures used in hydraulic fracturing. The EPA has not indicated when it intends to issue a proposed rule, but it issued an Advanced Notice of Proposed Rulemaking in May 2014, seeking public comment on a variety of issues related to such TSCA rulemaking. In October 2015, EPA also granted, in part, a petition filed by several national environmental advocacy groups to add the oil and gas extraction industry to the list of industries required to report releases of certain "toxic chemicals" to the environment under the Toxics Release Inventory ("TRI") program under of the Emergency Planning and Community Right-to-Know Act (EPCRA). That action resulted in EPA's publication in the Federal Register in January 2017, of proposed rules to achieve the inclusion of gas processing in EPCRA reporting requirements. Comments on the proposed rules were due in May 2017.

The U.S. Occupational Safety and Health Administration has proposed stricter standards for worker exposure to silica, which would apply to use of sand as a proppant for hydraulic fracturing. In addition, in December 2015 the U.S. Department of Labor and the U.S. Department of Justice ("DOJ") released a Memorandum of Understanding ("MOU"), announcing an interagency effort to increase enforcement of worker endangerment violations under environmental statutes (such as the Clean Water Act, the Clean Air Act, and the Resource Conservation and Recovery Act) and Title 18 criminal statutes that carry harsher penalties that the Occupational Safety and Health Act of 1970. Consistent with this MOU, where appropriate, DOJ will seek felony charges (such as false statements, conspiracy, and obstruction of justice) when prosecuting worker endangerment violations. In addition, Congress has considered, and may in the future consider, legislation that would amend the Safe Drinking Water Act ("SDWA") to encompass hydraulic fracturing activities. Past proposed legislation would have required hydraulic fracturing operations to meet permitting and financial assurance requirements, adhere to certain construction specifications, fulfill monitoring, reporting and recordkeeping obligations, including disclosure of chemicals used in the fracturing process, and meet plugging and abandonment requirements, in addition to those already applicable to well site reclamation under various federal and state laws. We routinely utilize hydraulic fracturing techniques in many of our reservoirs. As noted above, the EPA finalized a wide-ranging study on the effects of hydraulic fracturing on drinking water resources in 2016. Other governmental reviews have also been recently conducted or are under way that focus on environmental aspects of hydraulic fracturing. Adoption of legislation and implementing regulations placing restrictions on fracing could impose operational delays, increased operating costs and additional regulatory burdens on our exploration and production activities, which could make it more difficult to perform hydraulic fracturing, resulting in reduced amounts of oil and gas being produced, as well as increased costs of compliance and doing business. We disclose information pertaining to frac fluids, additives, and chemicals used in our operations to the FracFocus databases in compliance with statewide requirements established by the Texas Railroad Commission.

Employees

As of December 31, 2017, we had 128 full-time employees. We believe that we have a satisfactory relationship with our employees.

Offices

We currently lease approximately 56,000 square feet of office space in Denver, Colorado, and approximately 22,000 square feet of office space in Midland, Texas. Our principal office is located at 1700 Lincoln Street, Suite 2800, Denver, CO 80203. Of the 56,000 square feet leased space in Denver, as a result of the Aneth Disposition, we currently sublease approximately 8,000 square feet to an affiliate of Elk. The sublease is expected to expire on July 5, 2018, at which time we expect to resume occupancy of the space. We also own and maintain field offices in Texas and lease other, less significant, office space in locations where staff are located. We believe that our office facilities are adequate for our current needs and that additional office space can be obtained if necessary.

Available Information

We maintain a link to investor relations information on our website, www.resoluteenergy.com, where we make available, free of charge, our filings with the SEC, including our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, ("Exchange Act"), as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. We also make available on our website copies of the charters of the audit, compensation and corporate governance/nominating committees of our Board of Directors, our code of business conduct and ethics, audit committee whistleblower policy, stockholder and interested parties communication policy and corporate governance guidelines. Stockholders may request a printed copy of these governance materials or any exhibit to this report by writing to the Secretary, Resolute Energy Corporation, 1700 Lincoln Street, Suite 2800, Denver, CO 80203. You may also read and copy any materials we file with the SEC at the SEC's Public Reference Room, which is located at 100 F Street, NE, Room 1580, Washington, D.C. 20549. Information regarding the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains a website at www.sec.gov that contains the documents we file with the SEC. Our website and the information contained on or connected to our website is not incorporated by reference herein and our web address is included as an inactive textual reference only.

ITEM 1A. RISK FACTORS
You should consider carefully the following risk factors, as well as the other information set forth in this Form 10-K.

Risks Related to Our Business, Operations and Industry

The risk factors set forth below are not the only risks that may affect our business. Our business could also be affected by additional risks not currently known or that we currently deem to be immaterial. If any of the following risks were actually to occur, our business, financial condition or results of operations could be materially adversely affected.

Developing and producing oil and gas are costly and high-risk activities with many uncertainties that could adversely affect our financial condition or results of operations, and insurance may not be available or may not fully cover losses.

There are numerous risks associated with developing, completing and operating a well, and cost factors can adversely affect the economics of a well. Our development and producing operations may be curtailed, delayed or canceled as a result of other factors, including:

- reductions in oil or gas prices or increases in the differential between index oil or gas prices and prices received;
- high costs, shortages or delivery delays of rigs, equipment, labor or other services;
- unexpected operational events and/or conditions;
- increases in severance or other taxes;
- limitations on our ability to sell our oil or gas production;
- adverse weather conditions and natural disasters;
- facility or equipment malfunctions, and equipment failures or accidents;
- pipe or cement failures and casing collapses;
- compliance with environmental and other governmental regulations and requirements;
- environmental hazards, such as leaks, oil spills, pipeline ruptures and discharges of toxic gases;
- lost or damaged oilfield development and service tools;
- unusual or unexpected geological formations, and pressure or irregularities in formations;
- seismicity in the areas where we operate and the potential that drilling and completion activity or produced water injection/disposal would be limited in connection therewith;
- fires, blowouts, surface craterings and explosions;
- shortages or delivery delays of supplies, equipment and services;
- midstream constraints or downtime;
- title problems;
- objections from surface owners and nearby surface owners in the areas where we operate; and
- uncontrollable flows of oil, gas or well fluids.

Any of these or other similar occurrences could reduce our cash from operations or result in the disruption of our operations, substantial repair costs, significant damage to property, environmental pollution and impairment of our operations. The occurrence of these events could also affect third parties, including persons living near our operations, our employees and employees of our contractors, leading to injuries or death.

Insurance against all operational risk is not available to us, and pollution and environmental risks generally are not fully insurable. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. We do not maintain business interruption insurance and also may not maintain insurance on all of our equipment. Losses could, therefore, occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. Moreover, insurance may not be available in the future at commercially reasonable costs and on commercially reasonable terms, and any insurance coverage we do obtain may contain large deductibles or it may not cover all hazards or potential losses. Losses and liabilities from uninsured and underinsured events or a delay in the payment of insurance proceeds could adversely affect our business, financial condition and results of operations.

Oil and gas prices are volatile and change for reasons that are beyond our control. Sustained periods of low prices or decreases in the price we receive for our oil and gas production can adversely affect our business, financial condition, results of operations and liquidity and impede our growth.

The oil and gas markets are highly volatile, and we cannot predict future prices. Our revenue, profitability and cash flow depend upon the prices and demand for oil, gas and NGL. The markets for these commodities are very volatile and even relatively modest reductions in prices can significantly affect our financial results and impede our growth. Prices for oil, gas and NGL may fluctuate widely in response to relatively minor changes in the supply of and demand for the commodities, market uncertainty and a variety of additional factors that are beyond our control, such as:

- domestic and foreign supply of and demand for oil and gas, including as a result of technological advances affecting energy consumption and supply;
- actions of the Organization of Petroleum Exporting Countries and state-controlled oil companies relating to oil price and production controls;
- weather conditions;
- overall domestic and global political and economic conditions;
- the price of foreign imports;
- political and economic conditions in oil producing countries, including the Middle East, Russia and South America;
- variations between product prices at sales points and applicable index prices;
- domestic and foreign governmental regulations and taxation;
- the effect of energy conservation efforts;
- the capacity, cost and availability of oil and gas pipelines and other transportation and gathering facilities, and the proximity of these facilities to our wells;
- the availability of refining and processing capability;
- factors specific to the local and regional markets where our production occurs; and
- the price and availability of alternative fuels.

In the past, the price of oil has been extremely volatile, and we expect this volatility to continue. Oil and gas prices have declined substantially since mid 2014. For example, during the twelve months ended December 31, 2017, the NYMEX price for light sweet crude oil ranged from a high of $60.42 per Bbl to a low of $42.53 per Bbl. For calendar year 2016, the range was from a high of $54.06 per Bbl to a low of $26.21 per Bbl, and for the five years ended December 31, 2017, the price ranged from a high of $110.53 per Bbl to a low of $26.21 per Bbl.

A prolonged period of low oil and gas prices or a decline in oil and gas prices will significantly affect many aspects of our business, including financial condition, revenue, results of operations, liquidity, cash flow, rate of growth, reserves, the carrying value of our oil and gas properties, and the borrowing base under our revolving credit facility with a syndicate of lenders (the "Revolving Credit Facility"), all of which depend primarily or in part upon those prices. For example, declines in the prices we receive for our oil and gas adversely affect our ability to repay indebtedness, finance capital expenditures, make acquisitions, raise capital and otherwise satisfy our financial obligations. In addition, declines in prices reduce the amount of oil and gas that we can produce economically and, as a result, adversely affect our quantities and present values of proved reserves. Among other things, a reduction in our reserves can limit the capital available to us, as the maximum amount of available borrowing under our Revolving Credit Facility is, and the availability of other sources of capital likely will be, based to a significant degree on the estimated quantities and value of those reserves.

Inadequate liquidity could materially and adversely affect our business operations.

Our ability to generate cash flow depends upon numerous factors related to our business that may be beyond our control, including:

- the price at which we sell our oil and gas production and the costs we incur to market our production;
- the amount of oil and gas we produce;
- our ability to borrow under our Revolving Credit Facility or future debt agreements;

- debt service requirements contained in our Revolving Credit Facility, 8.5% senior notes due 2020 (the "Senior Notes") or future debt agreements;
- the effectiveness of our commodity price hedging strategy;
- the development of proved undeveloped and other prospective properties and the success of our enhanced oil recovery activities;
- the level of our operating and general and administrative costs;
- our ability to replace produced reserves;
- prevailing economic conditions;
- government regulation and taxation;
- the level of our capital expenditures required to implement our development projects and make acquisitions of additional reserves and prospective properties;
- fluctuations in our working capital needs; and
- timing and collectability of receivables.

Failure to maintain adequate liquidity could result in an inability to replace reserves and production, to maintain ownership of undeveloped leasehold and adverse borrowing base determinations. Any or all of the foregoing could materially and adversely affect our business and results of operations.

In addition, our estimate of proved reserves as of December 31, 2017, was based on a pricing methodology required by SEC rules. If low oil and gas prices result in our having to make substantial downward adjustments to our estimated proved reserves, or if our estimates of development costs increase, production data factors change or drilling results deteriorate, accounting rules may require us to make downward adjustments, as a non-cash impairment charge to earnings, to the carrying value of our oil and gas properties. When we incur impairment charges in the future, we could have a material adverse effect on our results of operations in the period incurred. In addition, a reduction in the future net cash flow from our properties would negatively affect our ability to borrow funds under our Revolving Credit Facility.

Availability under our Revolving Credit Facility depends on a borrowing base which is subject to redetermination by our lenders. If our borrowing base is reduced, we may be required to repay amounts outstanding under our Revolving Credit Facility.

Under the terms of our Revolving Credit Facility, our borrowing base is subject to semi-annual redetermination by our lenders based on their evaluation of our proved reserves and their internal criteria. In addition, under certain circumstances, interim redeterminations may be conducted, including in the event of acquisitions or dispositions of properties.

In the event the amount outstanding under our Revolving Credit Facility at any time exceeds the borrowing base at such time, we would be required to repay the amount of our outstanding borrowings exceeding the new borrowing base over the 120 days following the redetermination. If we do not have sufficient funds on hand for repayment, we may be required to seek a waiver or amendment from our lenders, refinance our Revolving Credit Facility, incur additional indebtedness, sell assets or sell additional debt or equity securities in order to cure such borrowing base deficiency. We may not be able to obtain such financing or complete such transactions on terms acceptable to us or at all. Failure to make the required repayment could result in a default under our Revolving Credit Facility and a cross default under our Senior Notes.

Our substantial indebtedness could adversely affect our business, results of operations and financial condition.

In addition to making it more difficult for us to satisfy our obligations to pay principal and interest on our outstanding indebtedness, our substantial indebtedness could limit our ability to respond to changes in the markets in which we operate and otherwise limit our activities. For example, our indebtedness, and the terms of agreements governing that indebtedness:

- require us to dedicate a substantial portion of our cash flow from operations to service our existing debt obligations, thereby reducing the cash available to fund our operations, exploration and development efforts, acquisitions, working capital, capital expenditures and other general corporate purposes;
- increase our vulnerability to economic downturns and impair our ability to withstand sustained declines in oil and gas prices;
- subject us to covenants that limit our ability to fund future working capital, capital expenditures, exploration costs and other general corporate requirements;

- may prevent us from borrowing additional funds for operational or strategic purposes (including to fund future acquisitions), disposing of assets or paying cash dividends;
- may prevent counterparties (including lenders) from entering into derivative transactions with us;
- limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and
- place us at a competitive disadvantage relative to our competitors that have less debt outstanding.

Covenants in our Revolving Credit Facility and the indenture governing our Senior Notes, currently impose, and future financing agreements may impose, significant operating and financial restrictions.

Our Revolving Credit Facility and the indenture governing our Senior Notes each contain restrictions, and future financing agreements may contain additional restrictions, on our activities, including covenants that restrict our and our restricted subsidiaries' ability to:

- incur additional debt;
- pay dividends on, redeem or repurchase stock;
- create liens;
- make specified types of investments;
- apply net proceeds from certain asset sales and equity offerings other than to repay indebtedness;
- engage in transactions with our affiliates;
- engage in sale and leaseback transactions;
- merge or consolidate;
- make payments from restricted subsidiaries;
- sell equity interests of restricted subsidiaries; and
- sell, assign, transfer, lease, convey or dispose of assets.

As amended in October 2017, our Revolving Credit Facility will mature in 2021 (unless there is a maturity of material indebtedness prior to such date) and is secured by substantially all of our oil and gas properties as well as a pledge of all ownership interests in our operating subsidiaries. The Revolving Credit Facility contains various affirmative and negative covenants, measured on a quarterly basis, including but not limited to financial covenants that (i) require us to maintain a ratio of current assets to current liabilities of no less than 1.0 to 1.0 and (ii) do not permit our maximum leverage ratio (total debt to consolidated Adjusted EBITDA as defined in the Revolving Credit Facility) to exceed 4.0 to 1.0.

These restrictions may prevent us from taking actions that we believe would be in the best interest of our business, may require us to sell assets or take other actions to reduce indebtedness to meet our covenants, and may make it difficult for us to successfully execute our business strategy or effectively compete with companies that are not similarly restricted. We may also incur future debt obligations that might subject us to additional restrictive covenants that could affect our financial and operational flexibility. We cannot provide assurance that we will be granted waivers or amendments to these agreements if for any reason we are unable to comply with these agreements, or that we will be able to refinance our debt on terms acceptable to us, or at all.

If we are unable to comply with the restrictions and covenants in the agreements governing the Revolving Credit Facility, Senior Notes and other debt, there could be a default under the terms of these agreements, which could result in an acceleration of payment of funds that we have borrowed and would affect our ability to make principal and interest payments on our debt.

If we are unable to generate sufficient cash flow and are otherwise unable to obtain funds necessary to meet required payments of principal, premium, if any, and interest on our indebtedness, or if we otherwise fail to comply with the various covenants, including financial and operating covenants, in the instruments governing our indebtedness (including our Revolving Credit Facility or the Senior Notes), we could be in default under the terms of the agreements governing such indebtedness, and any such default could cause a cross-default under the terms of our other indebtedness. In the event of such default, the holders of such indebtedness could elect to declare all the funds borrowed thereunder to be due and payable, together with accrued and unpaid interest, the lenders under our Revolving Credit Facility could elect to terminate their commitments, cease making further loans and our secured lenders could institute foreclosure proceedings against our assets, and we could be forced into bankruptcy or liquidation. We may in the future need to seek to obtain waivers from the required lenders under our Revolving Credit Facility to avoid being in default. If we breach our covenants under our Revolving Credit Facility and seek a waiver, we may not be able to obtain a waiver from the required lenders. If this occurs, we would be in default under our Revolving Credit Facility or Senior Notes, the lenders could exercise their rights as described above, and we could be forced into bankruptcy or liquidation.

In addition, any default under the agreements governing our indebtedness, including a default under our Revolving Credit Facility that is not waived by the required lenders, and the remedies sought by the holders of any such indebtedness, could make us unable to pay principal, premium, if any, and interest on the Senior Notes and other indebtedness and substantially decrease the market value of the Senior Notes.

The marketability of our production is dependent upon gathering, transportation and processing facilities the capacity and operation of which we do not control.

The marketability of our oil and gas production depends in part upon the availability, proximity and capacity of pipelines, gas gathering systems, gas processing facilities, water sourcing, gathering and disposal systems and oil gathering systems owned by third parties. In general, we do not control these facilities and our access to them may be limited or denied due to circumstances beyond our control. A significant disruption in the availability of these facilities could adversely affect our ability to deliver to market the oil and gas we produce, and thereby cause a significant interruption in our operations. In some cases, our ability to deliver to market our oil and gas is dependent upon coordination among third parties who own pipelines, transportation and processing facilities that we use, and any inability or unwillingness of those parties to coordinate efficiently could also interrupt our operations. Additionally, the amount of our oil and gas production in the Delaware Basin could exceed the capacity of, and result in strains on, the various gathering and transportation systems, pipelines, processing facilities, and other infrastructure available in that area. Federal and state regulation of oil and gas production and transportation, local government activity, adverse court rulings, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines, infrastructure or capacity constraints and general economic conditions could also adversely affect our ability to produce, gather, process, transport and market oil and gas. These are risks for which we generally do not maintain insurance.

Our strategy involves using some of the latest available horizontal drilling and completion techniques, which involve risks and uncertainties in their application.

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

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

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

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

The drilling process and the results of our drilling in new or emerging formations are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production. Newer or emerging formations and areas have limited or no drilling or production history and, consequently, we are more limited in assessing future drilling costs and results in these areas. If our drilling costs are greater or our results are less than anticipated, the return on our investment for a particular project may not be as attractive as we anticipated and we could incur material write-downs of unevaluated properties and the value of our undeveloped acreage could decline in the future.

Any acquisitions we complete are subject to substantial risks that could negatively affect our financial condition and results of operations.

Even if we do make acquisitions that we believe will enhance our growth, financial condition or results of operations, any acquisition involves potential risks including, among other things:

- the validity of our assumptions about the acquired properties' or company's reserves, future production, the future prices of oil and gas, infrastructure requirements, environmental and other liabilities, revenue and costs;
- an inability to integrate successfully the properties and businesses we acquire;
- a decrease in our liquidity to the extent we use a significant portion of our available cash or borrowing capacity to finance acquisitions or operations of the acquired properties;
- a significant increase in our interest expense or financial leverage if we incur debt to finance acquisitions or operations of the acquired properties;
- the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which our indemnity is inadequate;
- the diversion of management's attention from other business concerns;
- an inability to hire, train or retain qualified personnel to manage and operate our growing business and assets;
- unforeseen difficulties encountered in operating in new geographic areas; and
- customer or key employee losses at the acquired businesses.

Our decision to acquire a property or business will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses and seismic and other information, the results of which are often inconclusive and subject to various interpretations.

Also, our review of acquired properties is inherently incomplete because it is generally not feasible to perform an in-depth review of the individual properties involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and potential problems. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken. The potential risks in making acquisitions could adversely affect our ability to achieve anticipated levels of cash flows from the acquired businesses or realize other anticipated benefits of those acquisitions.

We and our subsidiary guarantors may be unable to fulfill our debt service obligations under our debt agreements.

We have a substantial amount of indebtedness. As a result, a significant portion of our cash flow will be required to pay interest and principal on our indebtedness, and we may not generate sufficient cash flow from operations, or have future borrowing capacity available, to enable us to pay amounts due on, or pay when due at maturity, our indebtedness, including the Revolving Credit Facility or the Senior Notes, or to fund other liquidity needs. As of December 31, 2017, we had $555.0 million in outstanding indebtedness.

Servicing our indebtedness and satisfying our other obligations will require a significant amount of cash. Our cash flow from operating activities and other sources may not be sufficient to fund our liquidity needs. Our ability to pay interest and principal on our indebtedness and to satisfy our other obligations will depend upon our future operating performance and financial condition and the availability of refinancing indebtedness, which will be affected by prevailing economic and industry conditions and financial, business and other factors, many of which are beyond our control. We cannot assure you that our business will generate sufficient cash flow from operations, or that future borrowings will be available to us under our Revolving Credit Facility or otherwise, in an amount sufficient to fund our liquidity needs, including the payment of principal and interest on the Revolving Credit Facility or the Senior Notes.

Declines in product prices decrease our operating cash flow. An increase in our expenses could make it difficult for us to meet debt service requirements and could require us to modify our operations, including curtailing our exploration and drilling programs, selling assets, issuing equity, reducing our capital expenditures, refinancing all or a portion of our existing debt or obtaining additional financing. These alternative measures may not be successful and may not permit us to meet our scheduled debt service obligations. Our ability to restructure or refinance our debt will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of our debt could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our business operations. In addition, the terms of future debt agreements may, and our Revolving Credit Facility and the indenture governing the Senior Notes do, restrict us from implementing some of these alternatives. In the absence of such operating results and resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations or issue equity at depressed prices to meet our debt service and other obligations. We may not be able to consummate these dispositions or equity issuances for fair market value or at all. Furthermore, any proceeds that we could realize from any dispositions or equity issuances may not be adequate to meet our debt service obligations then due.

Our estimated proved reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities of our proved reserves. Estimates of resource potential are also based on many assumptions and may turn out to be inaccurate.

Our estimate of proved reserves at December 31, 2017, is based on the quantities of oil and gas that engineering and geological analyses demonstrate with reasonable certainty to be recoverable from established reservoirs in the future under current operating and economic parameters. NSAI audited, on a well-by-well basis, the reserve and economic evaluations of all properties that were prepared by us. Oil and gas reserve engineering is not exact; it relies on subjective interpretations of data that may be inaccurate or incomplete and requires predictions and assumptions of future reservoir behavior and economic conditions. Estimates of economically recoverable oil and gas reserves and of future net cash flows depend upon a number of variable factors and assumptions, including:

- the assumed accuracy of field measurements and other reservoir data, including type curve forecast models;
- assumptions regarding expected reservoir performance relative to historical analog reservoir performance;
- the assumed effects of regulations by governmental agencies;
- assumptions concerning the availability of capital and its costs;
- assumptions concerning future oil and gas prices; and
- assumptions concerning future operating costs, severance and excise taxes, development costs and workover and remedial costs.

Because all reserve estimates are necessarily subjective, each of the following items may differ materially from those assumed in estimating reserves:

- the quantities of oil and gas that are ultimately recovered;
- the timing of the recovery of oil and gas reserves;
- the production and operating costs incurred; and
- the amount and timing of future development expenditures.

Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same available data. As a result of all these factors, we may make material changes to reserves estimates to take into account changes in our assumptions and the results of our development activities and actual drilling and production.

If these assumptions prove to be incorrect, our estimates of reserves, the economically recoverable quantities of oil and gas attributable to any particular group of properties, the classifications of reserves based on risk of recovery and our estimates of the future net cash flows from our reserves could change significantly.

In addition, the present value of the estimated future net cash flows from our proved reserves is not necessarily the same as the current market value of those reserves. Pursuant to SEC rules, the estimated future net cash flows from our proved reserves, and the estimated quantity of those reserves, were based on the arithmetic average of the prior year’s first day of the month oil and gas index prices.

In our press releases and investor presentations, we include estimates of quantities of oil and gas using certain terms, such as “resource,” “resource potential,” “EUR,” “oil in place,” or other descriptions of volumes of reserves, which terms include quantities of oil and gas that may not meet the SEC definition of proved, probable and possible reserves, and which the SEC guidelines strictly prohibit us from including in filings with the SEC. These estimates are by their nature more speculative than estimates of proved reserves and accordingly are subject to substantially greater risk of being recovered by Resolute. In addition, “peak IP rates” for both our wells and for those wells that are located near to our properties are limited data points in each well’s productive history and not necessarily indicative or predictive of future production rates, EUR or economic rates of return from such wells and should not be relied upon for such purpose. Our investor presentations also include type curve forecast models for well performance. Type curve forecast models are derived from the actual production of historical comparably drilled and completed wells and forecast expected well production, but actual production results may differ significantly from production forecasted by type curves. Type curve forecast models have an inherent degree of variability and may change over time, and as a result, may not be indicative of the actual well data for the type curve areas.

Sustained low commodity prices could result in additional impairments charges and we may be required to write down the carrying value of our properties in the future.

We use the full cost accounting method for oil and gas exploitation, development and exploration activities. Under the full cost method rules, we perform a ceiling test and if the net capitalized costs for a cost center exceed the ceiling for the relevant properties, we write down the book value of the properties. If low oil and gas prices result in our having to make substantial downward adjustments to our estimated proved reserves, or if our estimates of development costs increase, production data factors change or drilling results deteriorate, accounting rules may require us to make downward adjustments, as a non-cash impairment charge to earnings, to the carrying value of our oil and gas properties.

Our planned operations, as well as replacement of our production and reserves, will require significant additional capital that may not be available.

Our business is capital intensive, and requires substantial expenditures to maintain currently producing wells, to make the acquisitions of additional reserves and/or conduct the exploration, exploitation and development program necessary to replace our reserves, to pay expenses and to satisfy our other obligations. These activities will require cash flow from operations, additional borrowings or proceeds from the issuance of equity or asset sales, or some combination thereof, which may not be available to us.

For example, in 2018 we expect capital expenditures of between $365 million and $395 million. Additionally, based on our SEC-case reserve projections, we expect to spend $285.4 million of capital expenditures over the next five years to implement and complete our proved undeveloped projects. We expect to incur all of these future capital expenditures during 2018 through 2022 based on the capital plan contemplated by our year-end 2017 SEC reserve report. To the extent our production and reserves decline faster than we anticipate, we will require a greater amount of capital to maintain our production. Our ability to obtain bank financing or to access the capital markets for future equity or debt offerings may be limited by our financial condition at the time of any such financing or offering, the covenants in our Revolving Credit Facility or the Senior Notes, adverse market conditions or other contingencies and uncertainties that are beyond our control. Our failure to obtain the funds necessary for future activities could materially affect our business, results of operations and financial condition. Even if we are successful in obtaining the necessary funds, the terms of such financings could limit our activities and our ability to pay dividends. In addition, incurring additional debt may significantly increase our interest expense and financial leverage, and issuing additional equity may result in significant equity holder dilution.

If we are unable to acquire adequate supplies of water for our operations or are unable to dispose of the water we use and produce at a reasonable cost and within applicable environmental rules, our ability to produce oil and gas commercially and in commercial quantities could be impaired.

We use a substantial amount of water in our drilling and completion. Our inability to locate sufficient amounts of water, or treat and dispose of water after drilling and completion, and generated from production could adversely impact our operations. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of oil and gas. Furthermore, future environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells could increase operating costs and cause delays, interruptions or termination of operations, the extent of which cannot be predicted, all of which could have an adverse effect on our operations and financial performance.

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

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

Notwithstanding our current indebtedness levels and restrictive covenants, we may still be able to incur substantial additional debt or make certain restricted payments, which could exacerbate the risks described above.

We may be able to incur additional debt in the future. In addition, although the Revolving Credit Facility and the indenture governing the Senior Notes contain restrictions on our ability to incur indebtedness, those restrictions are subject to a number of exceptions. In particular, we may borrow under our Revolving Credit Facility. We expect to be able to issue additional notes under the indenture in some circumstances. In addition, if we are able to designate some of our restricted subsidiaries under the indenture as unrestricted subsidiaries, including in connection with the formation of master limited partnerships, those unrestricted subsidiaries would be permitted to borrow beyond the limitations specified in the indenture and engage in other activities in which restricted subsidiaries may not engage. We may also consider investments in joint ventures or acquisitions that may increase our indebtedness. In addition, under the indenture, we will be able to make restricted payments in certain circumstances. We may also be able to obtain waivers from the lenders under our Revolving Credit Facility and the holders of our Senior Notes that would permit us to increase the amount of indebtedness we are permitted to incur. Adding new debt to current debt levels or making otherwise restricted payments could intensify the related risks that we and our subsidiaries now face.

Although the Senior Notes are referred to as “senior,” rights to receive payments on the Senior Notes are effectively subordinated to the rights of our and our restricted subsidiaries’ existing and future secured creditors.

The lenders under our Revolving Credit Facility will have claims that are prior to the claims of holders of the Senior Notes to the extent of the value of the assets securing the Revolving Credit Facility. The Revolving Credit Facility is secured by liens on substantially all of our assets and the assets of our restricted subsidiaries. The Senior Notes are effectively subordinated to any secured indebtedness incurred under the Revolving Credit Facility and any future secured facilities of the Company. In the event of any distribution or payment of our or any guarantor’s assets in any foreclosure, dissolution, winding-up, liquidation, reorganization or other bankruptcy proceeding, holders of secured indebtedness will have prior claim to those of our or our restricted subsidiaries’ assets that constitute their collateral. Holders of Senior Notes will participate ratably with all holders of our unsecured indebtedness that is deemed to be of the same class as such notes, and potentially with all of our or any restricted subsidiary’s other general creditors, based upon the respective amounts owed to each holder or creditor, in our remaining assets. In any of the foregoing events, we cannot assure you that there will be sufficient assets to pay amounts due on the Senior Notes. As a result, holders of Senior Notes may receive less, ratably, than holders of secured indebtedness.

The Senior Notes are subordinated to all indebtedness of those of our existing or future subsidiaries that are not, or do not become, guarantors of the notes.

Although all of our current subsidiaries are guarantors of the Senior Notes, if any future subsidiaries do not become guarantors of the notes, they will have no obligation, contingent or otherwise, to pay amounts due under the notes or to make any funds available to pay those amounts, whether by dividend, distribution, loan or other payment. The notes will be structurally subordinated to all indebtedness and other obligations of any non-guarantor subsidiary such that, in the event of insolvency, liquidation, reorganization, dissolution or other winding up of any subsidiary that is not a guarantor, all of the subsidiary’s creditors (including trade creditors and preferred stockholders, if any) would be entitled to payment in full out of the subsidiary's assets before we would be entitled to any payment. In addition, the indenture governing the notes will, subject to some limitations, permit non-guarantor subsidiaries to incur additional indebtedness and will not contain any limitation on the amount of other liabilities, such as trade payables, that may be incurred by these subsidiaries.

We may not be able to repurchase the Senior Notes upon a change of control as required by the indenture governing the notes. A change of control is also an event of default under our Revolving Credit Facility.

Upon the occurrence of certain kinds of change of control events, we will be required to offer to repurchase all outstanding Senior Notes at 101% of the principal amount thereof plus accrued and unpaid interest, if any, to the date of repurchase, unless all notes have been previously called for redemption. The holders of other debt securities that we may issue in the future, which rank equally in right of payment with the notes, may also have this right. Our failure to purchase tendered notes would constitute an event of default under the indenture governing the notes, which in turn, would constitute an event of default under our Revolving Credit Facility. A "change of control" under the indenture governing our Senior Notes includes the acquisition by a third party of more than 50% of our outstanding common stock, which is a transaction that may occur without the approval of the Company's Board of Directors.

It is possible that we may not have sufficient funds at the time of the change of control to make the required repurchase of notes. Moreover, our Revolving Credit Facility restricts, and any future indebtedness we incur may restrict, our ability to repurchase the notes, including following a change of control event. As a result, following a change of control event, we would not be able to repurchase notes unless we first repay all indebtedness outstanding under our Revolving Credit Facility and any of our other indebtedness that contains similar provisions, or obtain a waiver from the holders of such indebtedness to permit us to repurchase the notes. We may be unable to repay all of that indebtedness or obtain a waiver of that type. Any requirement to offer to repurchase outstanding notes may therefore require us to refinance our other outstanding debt, which we may not be able to do on commercially reasonable terms, if at all. These repurchase requirements may also delay or make it more difficult for others to obtain control of us.

In addition, the occurrence of a change of control (as defined under the debt agreement) in itself would constitute an event of default under our Revolving Credit Facility.

Certain important corporate events, such as leveraged recapitalizations that would increase the level of our indebtedness, may not constitute a “Change of Control” under the indenture.

Following a sale of “substantially all” of our assets, we may not be able to determine if a change of control that would give rise to a right to have the Senior Notes repurchased has occurred or if a change of control that would give rise to an event of default under the Revolving Credit Facility has occurred.

The definition of change of control in the Revolving Credit Facility and the Senior Notes include a phrase relating to the sale of “all or substantially all” of our assets. There is no precise, established definition of the phrase “substantially all” under applicable law. Accordingly, the ability of a holder of Senior Notes to require us to repurchase its notes, and the occurrence of an event of default under the Revolving Credit Facility, as a result of a sale of less than all our assets to another person, may be uncertain. Further, a holder or holders of Senior Notes could take the position that a transaction or series of transactions constituted a “sale of substantially all assets” giving rise to the right to have the Senior Notes repurchased.

Provisions in the indenture governing our Senior Notes and in our Revolving Credit Facility may discourage third parties from seeking to consummate a change of control transaction that could otherwise be beneficial for our stockholders.

Upon the occurrence of certain kinds of change of control events, we will be required to offer to repurchase all outstanding Senior Notes at 101% of the principal amount thereof plus accrued and unpaid interest, if any, to the date of repurchase, unless all notes have been previously called for redemption. In addition, the occurrence of a change of control (as defined under the respective debt agreements) in itself would constitute an event of default under our Revolving Credit Facility, which would cause amounts outstanding under the Revolving Credit Facility to become immediately due and payable. The potential trigger of an event of default under the Revolving Credit Facility, as well as the potential repurchase obligation under the Senior Notes, may discourage potential third parties from entering into a change of control transaction with us that may otherwise be beneficial for our stockholders.

Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage or the leases are extended.

As of December 31, 2017, we had approximately 4,300 net acres in the Permian Basin that are not currently held by production. Unless production in paying quantities is established on units containing these leases during their primary term, their continuous drilling term or we obtain extensions of the leases, these leases will expire. If our leases expire, we will lose our right to develop the related properties.

Our drilling plans for these areas are subject to change based on various factors, including factors that are beyond our control, including drilling results, oil and gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints, and regulatory approvals.

Adverse U.S. and global economic conditions could have a material adverse effect on our business and operations.

Any or all of the following may occur if domestic and global economic conditions worsen:

- We may be unable to obtain additional debt or equity financing, which would require us to limit our capital expenditures and other spending. This would lead to lower growth in our production and reserves than if we were able to spend more than our cash flow. Financing costs may significantly increase as lenders may be reluctant to lend without receiving higher fees and spreads.
- An economic slowdown could lead to lower demand for oil and gas by individuals and industries, which may result in lower prices for the oil and gas sold by us, lower revenues and possibly losses.
- The lenders under our Revolving Credit Facility may become more restrictive in their lending practices or unable or unwilling to fund their commitments, which would limit our access to capital to fund our capital expenditures and

operations. This would limit our ability to generate revenues as well as limit our projected production and reserves growth, leading to declining production and possibly losses.

- The losses incurred by financial institutions as well as the bankruptcy of some financial institutions heightens the risk that a counterparty to our derivative instruments could default on its obligations. These losses and the possibility of a counterparty declaring bankruptcy may affect the ability of the counterparties to meet their obligations to us on derivative transactions, which could reduce our revenues from derivatives at a time when we are also receiving a lower price for our gas and oil sales. As a result, our financial condition could be materially adversely affected.
- Our Revolving Credit Facility bears a floating interest rate based on the London Interbank Offered Rate, or LIBOR. If LIBOR were to increase, this would cause higher interest expense.
- Our Revolving Credit Facility requires the lenders to re-determine our borrowing base semi-annually. The redeterminations are based largely on our proved reserves using price assumptions determined by each lender, with effect given to our derivative positions. It is possible that the lenders could reduce their price assumptions used to determine reserves for calculating our borrowing base and our borrowing base could be reduced. This would reduce our funds available to borrow and could require us to repay any amounts outstanding in excess of the then-determined borrowing base.
- Bankruptcies of purchasers of our oil and gas could lead to the delay or failure of us to receive the revenues from those sales.

A financial failure by us or our subsidiaries may result in the assets of any or all of those entities becoming subject to the claims of all creditors of those entities.

A financial failure by us or our subsidiaries could affect payment of the Revolving Credit Facility and the Senior Notes if a bankruptcy court were to substantively consolidate us and our subsidiaries. If a bankruptcy court substantively consolidated us and our subsidiaries, the assets of each entity would become subject to the claims of creditors of all entities. This would expose holders of Senior Notes not only to the usual impairments arising from bankruptcy, but also to potential dilution of the amount ultimately recoverable because of the larger creditor base. Furthermore, forced restructuring of the Senior Notes could occur through the “cramdown” provisions of the bankruptcy code. Under these provisions, the notes could be restructured over the objections of holders as to their general terms, primarily interest rate and maturity.

Exploration and development drilling may not result in commercially productive reserves.

We may not encounter commercially productive reservoirs through our drilling operations. The new wells we drill or participate in may not be productive and we may not recover all or any portion of our investment in such wells. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling whether we will find oil or gas or, if found, that the hydrocarbons will be produced economically. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Our efforts will be unprofitable if we drill dry wells or wells that are productive but do not produce enough reserves to return a profit after drilling, operating and other costs. Further, our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- increases in the cost of, or shortages or delays in the availability of, drilling rigs and equipment;
- unexpected drilling conditions;
- title problems;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions; and
- compliance with environmental and other governmental requirements.

Our identified drilling locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill such locations.

Our management team has specifically identified and scheduled certain drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including oil and gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering system and pipeline transportation constraints, access to and availability of water sourcing, distribution and disposal systems, regulatory approvals and other factors. Because of these uncertain factors, we do not know with certainty if the numerous drilling locations we have identified will ever be drilled or if we will be able to produce gas or oil from these or any other drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the drilling locations are obtained, the leases for such acreage will expire. As such, our actual drilling activities may materially differ from those presently identified.

The development of our estimated PUD reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated PUD reserves may not be ultimately developed or produced.

As of December 31, 2017, 51% of our total estimated proved reserves were classified as proved undeveloped. Development of these undeveloped reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Delays in the development of our reserves, increases in costs to drill and develop such reserves or decreases in commodity prices will reduce the value of our estimated PUD reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. If we choose not to develop our PUD reserves or suffer delays in their development as a result of such factors we could have to reclassify our PUD reserves as unproved reserves. Under the SEC’s reserve reporting rules, we may be required to write down our PUD reserves if we do not drill those wells within five years after their respective dates of initial booking.

Shortages of qualified personnel or field supplies, equipment and services could affect our ability to execute our plans on a timely basis, reduce our cash flow and adversely affect our results of operations.

The demand for qualified and experienced geologists, geophysicists, engineers, field operations specialists, landmen, financial experts and other personnel in the oil and gas industry can fluctuate significantly, often in correlation with oil and gas prices, causing periodic shortages. From time to time, there have also been shortages of drilling rigs and other field supplies, equipment and services, as demand for rigs and equipment increased along with the number of wells being drilled. These factors can also result in significant increases in costs for equipment, services, supplies and personnel. Higher oil and gas prices generally stimulate increased demand and result in increased prices for drilling rigs, crews and associated supplies, equipment and services. In the event of such shortages, our cash flow and operating results could be adversely affected and our ability to conduct our operations in accordance with our plans and budgets could be restricted.

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

Exploration, exploitation, development, production and marketing operations in the oil and gas industry are regulated extensively at the federal, state and local levels. Environmental and other governmental laws and regulations have increased the costs to plan, design, drill, install, operate and properly abandon oil and gas wells and other recovery operations. Under these laws and regulations, we could also be liable for personal injuries, property damage and other damages. Failure to comply with these laws and regulations may result in the suspension or termination of our operations or denial or revocation of permits and subject us to administrative, civil and criminal penalties.

Part of the regulatory environment in which we operate includes, in some cases, federal requirements for obtaining environmental assessments, environmental impact statements and/or plans of development before commencing exploration and production activities. Delays or failures in obtaining regulatory approvals or permits or the receipt of an approval or permit with unreasonable conditions could have a material adverse effect on our ability to exploit our properties. Additionally, the oil and gas regulatory environment could change in ways that might substantially increase the financial and managerial costs to comply with the requirements of these laws and regulations and, consequently, adversely affect our profitability. The expansion of GHG mandatory reporting rules (MRR) affecting onshore oil and gas activities and proposed GHG cap-and-trade legislation are two examples of recent and of proposed changes in the regulatory climate that do and would affect us. Also, the EPA announced a comprehensive strategy for further reducing methane emissions from oil and gas operations and issued a final rule in June 2016 (Clean Air Act NSPS Subpart OOOOa), although parts of those regulations are currently the subject of a proposed two-year stay by the EPA to allow for review, reconsideration, and possible rescission, as noted above. We may be placed at a competitive disadvantage to larger companies in the industry with respect to such expanded regulatory requirements, which can spread these additional costs over a greater number of wells and larger operating staff. Please read “Business and Properties — Environmental, Health and Safety Matters and Regulation” and “Business and Properties — Other Regulation of the Oil and Gas Industry” for a description of the laws and regulations that affect us.

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

Certain legislative proposals have been made that would terminate various tax incentives currently available to companies engaged in oil and gas development and production. These proposed changes have included (i) the elimination of the current deduction for intangible drilling and development costs and for qualified tertiary injectant expenses, (ii) the repeal of the percentage depletion allowance for oil and gas wells, and (iii) the extension of the amortization period for certain geological and geophysical expenditures. While these specific changes were not included in the Tax Act, additional legislative proposals affecting these tax incentives may be introduced, and, if such a proposal were to be enacted, the resulting impact could increase the cost of exploration and development of oil and gas resources. No accurate prediction can be made as to whether these or similar changes will be proposed or enacted in the future, but any such changes could have a material adverse effect on our financial position, results of operations and cash flows.

Proposed federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is a common process in our industry of creating artificial cracks, or fractures, in deep underground rock formations through the pressurized injection of water, sand and other additives to enable fluids (including oil and gas) to move more easily through the rock to a production well. This process often is necessary to produce commercial quantities of oil and gas from many reservoirs, especially shale rock formations. We routinely utilize hydraulic fracturing techniques in many of our reservoirs, including all of our wells in the Permian Basin. Current regulation of hydraulic fracturing primarily is conducted at the state level through permitting and other compliance requirements, but proposed regulations at the federal level have been under consideration by EPA, BLM and OSHA. The EPA is conducting a wide-ranging study on the effects of hydraulic fracturing on drinking water resources. In December 2015, the EPA issued a draft final report for public comment and peer review. Other governmental reviews have also been recently conducted or are under way that focus on environmental aspects of hydraulic fracturing. For example, a federal BLM rulemaking for hydraulic fracturing practices on federal and Indian lands was promulgated in 2015, and then challenged in federal court on numerous grounds. In June 2016, the United States District Court for the District of Wyoming held that the new regulations were invalid. Although the district court ruling was appealed, the rule was rescinded by BLM on December 29, 2017, and all related litigation is now concluded. Additionally, the U.S. Congress has considered legislation, and in the future may consider additional legislation, that would amend the SDWA to eliminate an existing exemption from federal regulation of hydraulic fracturing activities and require the disclosure of chemical additives used by the oil and gas industry in the hydraulic fracturing process. If adopted, the proposed amendments to the SDWA or these federal agencies' possible expansion of their existing regulatory programs affecting hydraulic fracturing could result in additional regulations and permitting requirements at the federal level. In addition, various states and localities are also studying or considering various additional regulatory measures related to hydraulic fracturing, and public referendums for moratoriums or additional restrictions on fracing have recently been presented in many state and local jurisdictions. These and similar developments could result in additional regulatory scrutiny that could make it difficult to perform hydraulic fracturing and increase our costs of compliance and of doing business. Additional regulations and permitting requirements could lead to significant operational delays and increased operating costs, and make it more difficult to perform hydraulic fracturing. We cannot assure you that any such outcome would not be material, and any such outcome could have a material and adverse impact on our cash flows and results of operations. Please read "Business and Properties —Other Regulation of the Oil and Gas Industry—Hydraulic Fracturing Disclosure and Possible Regulation or Prohibition" for a description of the potential further laws and regulations that may affect us.

Legislation or regulatory initiatives intended to address seismic activity could restrict our ability to dispose of saltwater produced in connection with our oil and gas production, which could limit our ability to produce oil and gas economically and have a material adverse effect on our business.

We dispose of large volumes of saltwater produced in connection with our drilling and production operations, pursuant to permits issued to us or third-party operators of disposal wells by governmental authorities overseeing produced water disposal activities. While these permits are issued pursuant to existing laws and regulations, these legal requirements are subject to change, which could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements, owing to, among other things, concerns of the public or governmental authorities regarding such disposal activities.

There exists a growing concern that the injection of produced water into deep belowground disposal wells may trigger seismic activity in certain areas, including Texas, where we operate. In response to these concerns, regulators in some states are pursuing initiatives designed to impose additional requirements in the permitting of saltwater disposal wells or otherwise to assess any relationship between seismicity and the use of such wells. For example, in 2015, the United States Geological Survey identified eight states, including Texas, with areas of increased rates of induced seismic activity that may be attributable to fluid injection or oil and gas extraction activities. In addition, a number of lawsuits have been filed in other states, including recently in Oklahoma, alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. In response to these concerns, regulators in some states are seeking to impose additional requirements, including requirements in the permitting of produced water disposal wells or otherwise to assess any relationship between seismicity and the use of such wells. For example, in October 2014, the Texas Railroad Commission, or TRC, published a new rule governing permitting or re-permitting of disposal wells in Texas that would require, among other things, the submission of information on seismic events occurring within a specified radius of the disposal well location, as well as logs, geologic cross sections and structure maps relating to the disposal area in question. If a permittee or a prospective permittee fails to demonstrate that the saltwater or other fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be or determined to be contributing to seismic activity, then the TRC may deny, modify, suspend or terminate the permit application or existing operating permit for that well.

The adoption and implementation of any new laws, regulations, or directives that restrict our ability to dispose of produced water, by changing the depths of disposal wells, reducing the volumes, injection pressures or rates of oil and gas wastewater disposal in such wells, restricting disposal well locations, or by requiring us or third parties who dispose of our saltwater to shut down disposal wells, could increase disposal costs or require us to shut in a substantial number of our oil and gas wells or otherwise have a material adverse effect on our ability to produce oil and gas economically and, accordingly, could materially and adversely affect our business, financial condition and results of operations.

The standardized measure of future net cash flows from our net proved reserves is based on many assumptions that may prove to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our proved reserves.

Actual future net cash flows from our oil and gas properties will be determined by the actual prices we receive for oil and gas, our actual operating costs in producing oil and gas, the amount and timing of actual production, the amount and timing of our capital expenditures, supply of and demand for oil and gas and changes in governmental regulations or taxation, which may differ from the assumptions used in creating estimates of future cash flows.

The timing of our production and our incurrence of expenses in connection with the development and production of oil and gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows in compliance with guidance from the FASB may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and gas industry in general.

We operate producing properties that are located in a limited number of geographic areas, making us vulnerable to risks associated with lack of geographic diversification.

Approximately 75% of our 2017 oil and gas revenues and 100% of our total proved reserves at December 31, 2017, are located in our Permian Basin Properties in west Texas. The remainder of our sales of oil and gas in 2017 were attributable to our Aneth Field Properties, which were sold in November 2017. As a result of our lack of diversification in asset type and location, any delays or interruptions of production caused by such factors as governmental regulation, transportation capacity constraints, curtailment of production or interruption of transportation, price fluctuations, natural disasters or shutdowns of the pipelines connecting our production to refineries would have a significantly greater impact on our results of operations than if we possessed more diverse assets and locations.

The prices we receive for our oil and gas production are affected by the geographic region in which that production is located. Prices are determined to a significant extent by factors affecting the regional supply of and demand for oil and gas, including the adequacy of the pipeline and processing infrastructure in the region to transport or process our production and that of other producers. Those factors result in basis differentials between the published indices generally used to establish the price received for regional oil and gas production and the actual (frequently lower) price we may receive for our production.

We have limited control over activities on properties we do not operate, which could reduce our production and revenues, affect the timing and amounts of capital requirements and potentially result in a dilution of our respective ownership interest in the event we are unable to make any required capital contributions.

We do not operate all of the properties in which we have an interest. As a result, we may have a limited ability to exercise influence over normal operating procedures, expenditures or future development of underlying properties and their associated costs. For all of the properties that are operated by others, we are dependent on their decision making with respect to day-to-day operations over which we have little control. The failure of an operator of wells in which we have an interest to adequately perform operations, or an operator’s breach of applicable agreements, could reduce production and revenues we receive from that well. The success and timing of our drilling and development activities on properties operated by others depend upon a number of factors outside of our control, including the timing and amount of capital expenditures, the available expertise and financial resources, the inclusion of other participants and the use of technology.

If the expenses associated with the operator’s activity exceed our expectations we may be required to make significantly higher capital contributions to satisfy our proportionate share of the costs. If such capital contributions are required, we may not be able to satisfy our obligations or we may have to reallocate our anticipated capital expenditure budget. In the event that we do not participate in future capital contributions with respect to a joint operating agreement or any other agreements relating to properties we do not operate, our ownership interest could be diluted or forfeited.

We participate in oil and gas leases with third parties who may not be able to fulfill their commitments to our projects.

On a limited basis, we own less than 100% of the working interest in the oil and gas leases on which we conduct operations, and other parties own the remaining portion of the working interest. We could be responsible for joint activity obligations of other working interest owners, such as nonpayment of costs and liabilities arising from the actions of other working interest owners. In addition, declines in commodity prices may increase the likelihood that some of these working interest owners will not be able to fulfill their joint activity obligations. A partner may be unable or unwilling to pay its share of project costs, and, in some cases, a partner may declare bankruptcy. In the event any of our project partners do not pay their share of such costs, we would likely have to pay those costs, and we may be unsuccessful in any efforts to recover these costs from our partners, which could materially adversely affect our financial position.

The inability of one or more of our customers or other counterparties to meet their obligations may adversely affect our financial results.

Substantially all of our accounts receivable result from our oil, gas and NGL sales or joint interest billings to a small number of third parties in the energy industry. This concentration of customers and joint interest owners may affect our overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. In addition, our derivatives expose us to credit risk in the event of nonperformance by counterparties. Finally, our agreement with Elk regarding additional future consideration payable in connection with our disposition of Aneth Field exposes us to credit risk in the event of non-performance by Elk and its affiliates. Nonperformance by our customers or counterparties may adversely affect our financial condition. We face similar risks with respect to our other counterparties, including the lenders under our Revolving Credit Facility and the providers of our surety bonds and insurance coverage.

We may not be able to keep pace with technological developments in our industry.

The oil and gas industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, competitors may have greater financial, technical, and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. One or more of the technologies we currently use or implement in the future may become obsolete. We cannot be certain we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. If we are unable to maintain technological advancements consistent with industry standards, our operations and financial condition may be adversely affected.

Our derivative activities could result in financial losses or reduced income from failure to pay by our counterparties, could reduce our net income, and could result in volatility in our net income.

To achieve more predictable cash flow and to reduce our exposure to adverse changes in the price of oil and gas, we have entered into, and plan to enter into in the future, derivative arrangements covering a significant portion of our oil and gas production. These derivative arrangements could result in both realized and mark-to-market derivative losses. Our derivative instruments are subject to mark-to-market accounting treatment, and the change in fair market value of the instrument is reported in our consolidated statements of income each quarter, which have resulted in, and will in the future likely result in, significant mark-to-market net gains or losses. Please read – "Management's Discussion and Analysis of Financial Condition and Results of Operations — How We Evaluate Our Operations" and "Management's Discussion and Analysis of Financial Condition and Results of Operations — Quantitative and Qualitative Disclosures About Market Risk."

In addition, our derivative activities are subject to the risk that a counterparty may not perform its obligation under the applicable derivative instrument. If derivative counterparties are unable to make payments to us under their derivative arrangements, our results of operations, financial condition and liquidity would be adversely affected.

Our actual future production during a period may be significantly higher or lower than we estimate at the time we enter into derivative transactions for such period. If the actual amount is higher than we estimate, we will have more unhedged production and therefore greater commodity price exposure than we intended. If the actual amount is lower than the nominal amount that is subject to our derivative financial instruments, whether due to issues with our sales to purchasers, natural declines in production and the failure to develop new reserves or other factors, we might be forced to satisfy all or a portion of our derivative transactions in cash without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a substantial reduction of our liquidity. As a result of these factors, our derivative activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows.

The effectiveness of derivative transactions to protect us from future oil and gas price declines will be dependent upon oil and gas prices at the time we enter into future derivative transactions as well as our future levels of hedging, and as a result our future net cash flow may be more sensitive to commodity price changes.

Our Revolving Credit Facility as amended on October 18, 2017, prohibits us from entering into derivative arrangements (i) for the first year, the greater of 85% of our anticipated production from proved properties or 75% of our anticipated projected production from properties, (ii) for the second year, 85% of anticipated projected production from proved properties and (iii) for the period after such two year period, the greater of 75% of our anticipated production from proved properties or 85% of our production from projected proved developed producing properties (not to exceed a term of 60 months for any such derivative agreement) using economic parameters specified in our Revolving Credit Facility. The prices at which we hedge our production in the future will be dependent upon commodity prices at the time we enter into these transactions. Accordingly, our commodity price hedging strategy will not protect us from significant and sustained declines in oil and gas prices received for our future production. Conversely, our commodity price hedging strategy may limit our ability to realize cash flow from commodity price increases. It is also possible that a larger percentage of our future production will not be hedged as our derivative policies may change, which would result in our oil and gas revenue becoming more sensitive to commodity price changes.

Legislation and regulation affecting derivative instruments could adversely affect our ability to hedge oil and gas prices which may increase our costs and adversely affect our profitability.

In July 2010, former President Obama signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank"). Dodd-Frank imposes restrictions on the use and trading of certain derivatives, including our oil and gas derivative instruments, and could have a number of effects on us, including the following:

- Depending on the rules and definitions adopted by regulators, we could be required to post significant amounts of cash collateral with our dealer counterparties for our derivative transactions, which would likely make it impracticable to implement our current hedging strategy.
- If our ability to enter into derivative transactions is decreased as a result of Dodd-Frank, we would be exposed to additional risks related to commodity price volatility. Commodity price decreases would then have an immediate significant adverse effect on our profitability and revenues. Reduced derivative transactions may also impair our ability to have certainty with respect to a portion of our cash flow, which could lead to decreases in capital spending and, therefore, decreases in future production and reserves.
- We expect that the cost to enter into derivative transactions will increase as a result of a reduction in the number of counterparties in the market and the pass-through of increased counterparty costs, thereby increasing the costs of derivative instruments. Our derivatives counterparties may be subject to significant new capital, margin and business conduct requirements imposed as a result of the new legislation.

- Dodd-Frank contemplates that most swaps will be required to be cleared through a registered clearing facility and traded on a designated exchange or swap execution facility. There are some exceptions to these requirements for entities that use swaps to hedge or mitigate commercial risk. While we may ultimately be eligible for such exceptions, the scope of these exceptions currently is uncertain, pending further definition through rule making proceedings.
- The above factors could also affect the pricing of derivatives and make it more difficult for us to enter into hedging transactions on favorable terms or at all.

The nature of our assets exposes us to significant costs and liabilities with respect to environmental and operational safety matters.

We may incur significant costs and liabilities as a result of environmental, health and safety requirements applicable to our oil and gas exploration, production and other activities. These costs and liabilities could arise under a wide range of environmental, health and safety laws and regulations, including agency interpretations thereof and governmental enforcement policies, which have tended to become increasingly strict over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of investigatory, cleanup and site restoration costs and liens, the denial or revocation of permits or other authorizations and the issuance of injunctions to limit or cease operations. Compliance with these laws and regulations also increases the cost of our operations and may prevent or delay the commencement or continuance of a given operation. In addition, claims for damages to persons or property may result from environmental and other impacts of our operations.

Strict or joint and several liability to remediate contamination may be imposed under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. New or modified environmental, health or safety laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. Please read “Business and Properties — Environmental, Health and Safety Matters and Regulation” for more information.

We may be unable to compete effectively with larger companies, which may adversely affect our operations and profitability.

The oil and gas industry is intensely competitive, and we compete with companies that have greater resources, including an increased ability to attract, compensate and retain quality employees. Many of these companies not only explore for and produce oil and gas, but also refine and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for oil and gas properties and exploratory prospects or identify, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration or exploitation activities during periods of low oil and gas market prices. Our larger competitors may be able to absorb the burden of present and future federal, state, local and other laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will depend upon our ability to evaluate and select suitable properties and to consummate transactions in this highly competitive environment.

Possible regulation related to global warming and climate change could have an adverse effect on our operations and demand for oil and gas.

Certain studies have suggested that human-caused emissions of GHGs, including CO_2 and methane, are contributing to the warming of the Earth’s atmosphere and significant physical effects, such as increased frequency and severity of storms, floods and other climatic events, any of which could have an adverse effect on our operations. In response to such studies, the U.S. Congress has considered, and in the future may consider, legislation to reduce emissions of GHGs. In addition, federal and state courts and administrative agencies are considering the scope and scale of climate change regulation under various laws pertaining to the environment, energy use and development, and several states have already taken legal measures to reduce emissions of GHGs. Federal, state and local governments may also pass laws mandating the use of alternative energy sources, such as wind power and solar energy, which may reduce demand for oil and gas. As a result of the U.S. Supreme Court's decision in April 2007, in Massachusetts v. EPA and subsequent decisions, the EPA also has begun to regulate GHG emissions from mobile and stationary sources under the Clean Air Act, even though Congress has not enacted new legislation specifically authorizing such regulation. In June 2014, the United States Supreme Court invalidated part of the EPA's stationary source GHG program in Utility Air Regulatory Group v. EPA, but the Supreme Court also ruled that major sources subject to the PSD or Title V programs because of non-GHG pollutant emissions could be subjected to certain "best available control technology" requirements to curb their GHG emissions.

In January 2015, former President Obama announced a comprehensive strategy to further reduce methane emissions from the oil and gas sector. As part of this strategy, in September 2015 the EPA published proposed amendments to the 2012 New Source Performance Standards ("NSPS") Subpart OOOO rules focused on achieving additional methane and volatile organic compound reductions from the oil and gas industry. In June 2016 EPA published final amendments to the 2012 NSPS Subpart OOOO rules, as well as new final rules focused on achieving additional methane and volatile organic compound reductions from the oil and gas industry. The new final rules in NSPS Subpart OOOOa impose requirements for leak detection and repair, control requirements at hydraulically fractured oil well completions, replacement of certain pneumatic pumps and controllers, and additional control requirements for gathering, boosting, and compressor stations, among other things. These final revised and new rules issued in 2013, 2014 and 2016 require modifications to our operations as promulgated, increasing our capital and operating costs. The revised and new final rules in NSPS Subparts OOOO and OOOOa are the subject of numerous court challenges currently pending in the federal Court of Appeals for the District of Columbia Circuit, although the rules remain effective and have not been stayed. Finally, EPA has recently proposed a two-year stay of the Subpart OOOOa rules to allow for their further reconsideration, revision or rescission.

Additionally, the federal Bureau of Land Management (BLM) has finalized standards for reducing venting and flaring on public lands. The final rule was published in the Federal Register on November 18, 2016. The final rule is the subject of pending litigation in the District of Wyoming federal court by industry members and certain states seeking to overturn the rule in part. Although the court denied a request for preliminary injunction to prevent the rule from taking effect on January 17, 2017, the District of Wyoming litigation is ongoing. In addition to the Wyoming litigation, there was litigation over a proposed stay of the rule in the Northern District of California. The 2016 final rule included two different categories of requirements and implementation deadlines, one effective in 2017 and one in 2018. The 2017 requirements that included, among others, a "waste minimization plan," are still in effect and implementation is ongoing. In December 2017, the BLM published a final rule suspending the remaining 2018 requirements for two years. Continued litigation and/or updates to the rule are expected. The EPA and BLM actions are part of a series of steps by the Obama administration that were intended to result by 2025 in a 40-45% decrease in methane emissions from the oil and gas industry as compared to 2012 levels.

In addition, substantial limitations on GHG emissions in other sectors, such as the power sector under the EPA's August 2015 Clean Power Plan, the implementation of which was stayed indefinitely by the U.S. Supreme Court in February 2016, could adversely affect demand for the oil and gas we produce. Further GHG regulation may result from the December 2015 agreement reached at the United Nations climate change conference in Paris ("Paris Agreement"). The United States was actively involved in the international negotiations in Paris. Pursuant to the Paris Agreement, the United States made an initial pledge to a 26-28% reduction in its GHG emission by 2025 against a 2005 baseline and committed to periodically update its pledge in five-year intervals starting in 2020. The Paris Agreement sets a goal of keeping global warming well below a two degrees Celsius increase and sets a target limit of 1.5 degrees. The Paris Agreement was signed by the United States in April 2016, though the Trump administration has announced its intention to withdraw from the agreement. Passage of state or federal climate control legislation or other regulatory initiatives or the adoption of regulations by the EPA and state agencies that restrict emissions of GHGs in areas in which we conduct business could have an adverse effect on our operations and demand for oil and gas.

It is uncertain whether our operations and properties, located in the southern region of the United States, are exposed to possible physical risks, such as severe weather patterns due to climate change, whether or not climate change is being caused or contributed to by human-caused emissions of GHGs.

In the courts, several decisions have been issued that may increase the risk of claims being filed by governments and private parties against companies that have significant GHG emissions. Such cases may seek to challenge air emissions permits that GHGs emitters apply for and seek to force emitters to reduce their emissions or seek damages for alleged climate change impacts to the environment, people, and property. Any laws or regulations that may be adopted to restrict or reduce emissions of GHGs could require us to incur additional operating costs, such as costs to purchase and operate emissions control systems or other compliance costs, and could reduce demand for our products.

Recently approved final rules regulating air emissions from gas processing operations could cause us to incur increased capital expenditures and operating costs, which may be significant.

In April 2012, the EPA issued final rules that established additional emission controls for newly constructed or modified oil and gas production and gas processing operations, the NSPS Subpart OOOO rules. After several parties challenged these regulations in court, the EPA administratively reconsidered certain of the rules' requirements. As a result of such administrative reconsideration, the EPA issued final amendments to the NSPS subpart OOOO regulations in September 2013 and December 2014. Specifically, the EPA's revised rules included provisions to address emissions of sulfur dioxide and VOC and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and gas production and processing activities. The final Subpart OOOO rules include a 95% reduction in VOCs emitted by requiring the use of reduced emission completions or "green completions" on all hydraulically-fractured gas wells constructed or refractured after January 1, 2015. The rules also established specific new requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment. In June 2016, EPA published additional final amendments to the 2012 NSPS Subpart OOOO rules, as well as new final rules focused on achieving additional methane and VOC reductions from the oil and natural gas industry. The new final rules in NSPS Subpart OOOOa impose requirements for leak detection and repair, control requirements at hydraulically fractured oil well completions, replacement of certain pneumatic pumps and controllers, and additional control requirements for gathering, boosting, and compressor stations, among other things. The revised and new final rules in NSPS Subparts OOOO and OOOOa are the subject of numerous court challenges currently pending in the U.S. Court of Appeals for the District of Columbia Circuit, although the rules remain effective. Additionally, the EPA has proposed a two year stay of the NSPS OOOOa rule to allow for the further reconsideration and possible revision or rescission.

In December 2014, the EPA also proposed to revise and lower the existing 75 ppb National Ambient Air Quality Standard ("NAAQS") for ground-level ozone under the federal Clean Air Act to a range within 60-70 ppb. On October 1, 2015, EPA finalized a rule lowering the standard to 70 ppb. In November 2016, EPA proposed a rule for implementing the new NAAQS, classifying nonattainment areas, and related State Implementation Plan requirements. The lowered ozone NAAQS could result in an expansion of ozone nonattainment areas across the United States, including areas in which we operate. Oil and gas operations in ozone nonattainment areas would likely be subject to increased regulatory burdens in the form of more stringent emission controls, emission offset requirements for new sources, and increased permitting delays and costs. These rules and air quality standard revisions could require a number of modifications to our operations, including the installation of new equipment to control emissions from our wells. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

We depend on a limited number of key personnel who would be difficult to replace.

We depend substantially on the performance of our executive officers and other key employees. We have entered into employment agreements with certain of these employees, but we do not maintain key personnel life insurance policies on any of these employees. The loss of any member of the senior management team or other key employees could negatively affect our ability to execute our business strategy.

Work stoppages, protests or other labor issues at our facilities could adversely affect our business, financial position, results of operations, or cash flows.

Although we believe that our relations with our employees are generally satisfactory, we may be subject to work stoppages at the facilities of our customers or suppliers, which may negatively affect our business. If any of our customers experience a material work stoppage, the customer may halt or limit the purchase of our products. Moreover, if any of our suppliers experience a work stoppage, our operations could be adversely affected if an alternative source of supply is not readily available. Any of these events could be disruptive to our operations and could adversely affect our business, financial position, results of operations, or cash flows.

Terrorist attacks aimed at our facilities or operations could adversely affect our business.

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

We are subject to cyber security risks.

A cyber incident could occur and result in information theft, data corruption, operational disruption and/or financial loss. The oil and gas industry has become increasingly dependent on digital technologies to conduct certain exploration, development, production, processing, distribution and accounting activities. For example, we depend on digital technologies to interpret seismic data, manage drilling rigs, production equipment and gathering transportation systems, conduct reservoir modeling and reserves estimation, and process and record financial and operating data. Pipelines, refineries, power stations and distribution points for both fuels and electricity are becoming interconnected by computer systems. At the same time, cyber incidents, including deliberate attacks or unintentional events, have increased. Our technologies, systems, networks, and those of our vendors, suppliers and other business partners may become the target of cyber attacks or information security breaches that could result in unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of business operations. In addition, certain cyber incidents may remain undetected for an extended period. Our systems and insurance coverage for protecting against cyber security risks may not be sufficient. We recently became victims of a “spear phishing” attack on one of our employees in which sensitive employee information was stolen. We immediately took all necessary and appropriate steps to mitigate losses for the Company and the individuals whose information was compromised. Although to date we have not experienced any material financial losses relating to cyber attacks, we may suffer such losses in the future. We may be required to expend significant resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities.

Conservation measures and technological advances could reduce demand for oil and gas.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and gas. The impact of the changing demand for oil and gas could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Restrictions on drilling activities intended to protect certain species of wildlife may adversely affect our ability to conduct drilling activities in some of the areas where we operate.

The Endangered Species Act restricts activities that may affect endangered or threatened species or their habitats. Oil and gas activities in our operating areas can be adversely affected by seasonal or permanent restrictions on drilling and other operating activities designed to protect various species and their habitat. The U.S. Fish and Wildlife Service published a final rule on February 11, 2016, that clarifies, interprets, and makes minor edits to the scope and purpose, adds and removes some definitions, and clarifies the criteria and procedures for designating critical habitat. Changes in listed species and their critical habitat designations may lead to seasonal restrictions that could limit our ability to operate in protected areas and can intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which then could lead to periodic shortages when drilling is allowed. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs. Permanent restrictions imposed to protect endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. The designation of previously unprotected species in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures and could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce our reserves.

Our plans for future strategic acquisitions may require substantial capital, which we may be unable to obtain on favorable terms or at all and which is likely to require us to incur additional indebtedness.

Our industry is capital intensive, and one component of our strategy has been to grow our reserves and production by acquiring oil and gas producing and undeveloped properties. We actively evaluate the acquisition of properties that are prospective for production of oil, gas and NGL, particularly in the Permian Basin. Future acquisitions that we may pursue may require us to incur additional indebtedness and leverage our existing assets. To date, we have financed such acquisitions primarily with proceeds from equity issuances, bank borrowings under our Revolving Credit Facility, cash generated by operations and the issuance of the Senior Notes. We could finance future acquisitions utilizing similar financing sources, which may include amending our Revolving Credit Facility and expanding the borrowing base and the sale of equity or debt securities. There can be no assurance as to the availability of any additional financing or that the terms will be acceptable to us. Our inability to obtain additional financing or sufficient financing on favorable terms may adversely affect our growth, competitiveness and profitability. Further, the incurrence of additional indebtedness could have material adverse effects on our financial condition and liquidity and limit our future flexibility and growth opportunities.

If we do not make acquisitions of reserves on economically acceptable terms, our future growth and ability to maintain production will be limited to only the growth we may achieve through the development of our proved developed non-producing and proved undeveloped reserves and exploration of our non-proved leaseholds.

Producing oil and gas reservoirs are generally characterized by declining production rates that vary depending upon reservoir characteristics and other factors. The rate of decline we have projected for our existing wells may be different than the decline rate actually realized. Our future oil and gas reserves and production and, therefore, our cash flow and income are highly dependent upon our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves.

We intend to grow by bringing our proved developed non-producing reserves into production, developing our proved undeveloped reserves and exploring for and finding additional reserves on our unproved properties. Our ability to further grow depends in part on our ability to make acquisitions. We may be unable to make such acquisitions because we are:

- unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with the seller;
- unable to obtain financing for these acquisitions on economically acceptable terms; or
- outbid by competitors.

If we are unable to acquire properties containing proved reserves at acceptable costs, our total level of proved reserves and associated future production will decline as a result of the ongoing production of our reserves.

Delaware law, our amended and restated certificate of incorporation and bylaws and our stockholder rights plan could impede or discourage a takeover that our stockholders may consider favorable.

Our amended and restated certificate of incorporation and bylaws have provisions that could deter, delay or prevent a third party from acquiring us. These provisions include:

- limitations on the ability of stockholders to amend our charter documents, including stockholder supermajority voting requirements;
- the inability of stockholders to act by written consent or to call special meetings;
- a classified Board of Directors with staggered three-year terms;
- the authority of our Board of Directors to issue, without stockholder approval, up to 1,000,000 shares of preferred stock with such terms as the Board of Directors may determine and to issue additional shares of our common stock;
- advance notice procedures with respect to stockholder proposals and the nomination of candidates for election as directors; and
- a stockholder rights plan, that was approved by the Company's stockholders at the 2017 annual meeting in May 2017, that allows any common stockholder to purchase Series A Junior Participating Preferred Stock for a specified amount 10 days after the public announcement that a person or a group has become an "Acquiring Person."

Stock prices of equity securities can be volatile, and there is no assurance that a holder of our common stock will be able to resell the common stock purchased at a price in excess of the purchase price.

The stock prices of companies on the U.S. securities markets have been volatile, increasing or decreasing not only in response to the company financial or operating results, but the general economic trends or events. In addition, stock prices of companies in the oil and gas industry are significantly affected by commodity prices for oil and gas. In particular, our stock price was very volatile during 2017, trading between $23.64 and $49.14 per share. All of these factors are beyond our control, and could have drastic impacts occurring within short periods of time. These factors could cause a decrease in the stock price following purchase, and a purchaser of our stock may not be able to sell their common stock for a price exceeding the purchase price.

Future sales of our common stock in the public or private markets could adversely affect the trading price of our common stock, substantially dilute existing stockholders and our ability to continue to raise funds in new equity offerings.

Future sales of our common stock, or securities convertible into or exercisable for, our common stock in public or private offerings could result in substantial dilution to existing stockholders, could potentially adversely affect the trading price of our common stock and could impair our ability to raise capital through future offerings of securities. This is particularly true if such sales occur at depressed stock prices. In addition, the perceived risk of dilution may cause some stockholders to sell their shares, which may further reduce the market price of our common stock.

If we were to experience an “ownership change,” we could be limited in our ability to use certain tax attributes arising prior to the ownership change to offset future taxable income.

If we were to experience an "ownership change," as determined under section 382 of the Internal Revenue Code of 1986, as amended, our ability to offset taxable income arising after the ownership change by utilizing NOLs arising prior to the ownership change would be limited, possibly substantially. Additionally, the deductibility of any pre-ownership change disallowed interest expense carryforward amount pursuant to the Tax Act’s limitation of the deductibility of net business interest expense, would also be limited post-ownership change. An ownership change would establish an annual limitation on the amount of our pre-ownership change losses, including NOLs and disallowed interest expense carryforward, that we could utilize in any future taxable year to an amount generally equal to the value of our stock immediately prior to the ownership change multiplied by the long-term tax-exempt rate.

Future Treasury Regulations relating to, and interpretations of, recently enacted U.S. federal income tax laws may vary from our current interpretation of such laws.

The recently enacted Tax Act is highly complex and there are numerous interpretive issues and ambiguities in connection with the Tax Act that require guidance and that are not clearly addressed by its legislative history. The presentation of our financial condition and results of operations is based upon our current interpretation of the provisions contained in the Tax Act. Our analysis of the Tax Act may be impacted by any corrective legislation and by any guidance provided by the U.S. Department of Treasury, the U.S. Internal Revenue Service or by the General Explanation of the Tax Act, which is under preparation by the staff of the Congressional Joint Committee on Taxation. Any significant variance of our current interpretation of the Tax Act from any future Treasury Regulations or other interpretive guidance could result in a change to the presentation of our financial condition and results of operations and could negatively affect our business.

Risks Related to the disposition of our Aneth Field Properties

We repositioned Resolute to a pure-play Delaware Basin company by disposing of our Aneth Field Properties, and the divesture could materially adversely affect our business, financial position, results of operations or cash flows.

In November 2017, we disposed of our Aneth Field Properties in order to reposition us as a pure-play Delaware Basin company. The disposition of Aneth Field Properties provided meaningful additional capital to the Company. This capital was deployed initially to reduce leverage.

Aneth Field was a meaningful part of our operations, and sales of oil and gas from Aneth Field represented a meaningful part of our total cash flow. At December 31, 2016, Aneth Field held approximately 41% of our net proved reserves and averaged production of 6,161 Boe per day in 2016 (representing 44% of total Company production), of which approximately 95% was oil. During 2016, Aneth Field had sales of 2,132 MBbl of oil and 739 MMcf of gas with average realized prices of $36.37 per Bbl of oil and $1.31 per Mcf of gas with average production costs of $20.24 per Boe of lease operating expenses and $4.31 per Boe of production and ad valorem taxes. Additionally at December 31, 2016, Aneth Field consisted of 43,218 developed gross acres or 67.1% of our total developed gross acreage and 27,157 developed net acres or 60.5% of our total developed net acreage.

For the twelve months ended December 31, 2017, Aneth Field averaged production of 4,974 Boe per day (representing 20% of total Company production). These 2017 sales were comprised of 1,734 MBbl of oil and 489 MMcf of gas with average realized prices of $42.44 per Bbl of oil and $1.72 per Mcf of gas with average production costs of $21.57 per Boe of lease operating expenses and $5.02 per Boe of production and ad valorem taxes.

The price we ultimately receive from the divestiture of the Aneth Field Properties will be contingent on the price of oil whereby we may receive up to $35 million in additional consideration if oil prices exceed certain levels in the three years following the closing (as specified in the additional cash consideration clause outlined in Note 3 to the Condensed Consolidated Financial Statements) and may be affected by the foregoing or other factors. This additional consideration is an unsecured obligation of the parent entity of the buyer and therefore may not be collectible in the future. Additionally, there can be no assurances that our subsequent investments in the Delaware Basin from the proceeds and the redeployment of resources made available by the sale of our Aneth Field Properties will meet our internal production and profitability projections for a pure-play Delaware Basin strategy or even meet current production and profitability projections prior to divesting of the Aneth Field Properties. We previously depended in part on the cash flow generated by our Aneth Field Properties for the payment of our indebtedness, and if we do not meet our internal projections and experience lower cash flow due to the sale of our Aneth Field Properties, it may materially adversely affect our ability make payments on our outstanding indebtedness. Consequently, the sale of our Aneth Field Properties could materially adversely affect our business, financial position, results of operations or cash flows.

Risks Related to the Delaware Basin acquisitions

The Delaware Basin acquisitions may not achieve their intended results.

We consummated the Delaware Basin Firewheel Acquisition and the Delaware Basin Bronco Acquisition with the expectation that these acquisitions would result in various benefits, growth opportunities and synergies. Achieving the anticipated benefits of any transaction is subject to a number of risks and uncertainties. Title and other problems could reduce the value of the properties to us, and, depending on the circumstances, we could have limited or no recourse to Firewheel with respect to those problems. We assumed substantially all of the liabilities associated with the acquired properties and will be entitled to indemnification in connection with those liabilities in only limited circumstances and limited amounts. We cannot assure you that such potential remedies will be adequate for any liabilities we incur, and such liabilities could be significant.

The success of these acquisitions depends on, among other things, the accuracy of our assessment of the reserves associated with the acquired properties, future oil, NGL and gas prices and operating costs and various other factors. These assessments are necessarily inexact. As a result, we may not recover the purchase price for an acquisition from the sale of production from the property or recognize an acceptable return from such sales. Although the properties acquired are subject to many of the risks and uncertainties to which our business and operations are subject, risks associated with these acquisitions include those associated with the significant size of the transaction relative to our existing operations.

The reserves and production estimates with respect to the properties acquired in the Delaware Basin acquisitions may differ materially from the actual amounts.

The reserves and production estimates with respect to the properties acquired in the Delaware Basin Firewheel Acquisition and the Delaware Basin Bronco Acquisition are based on our analysis of historical production data, assumptions regarding capital expenditures and anticipated production declines. We cannot assure you that these estimates are accurate.

Risks Related to our Convertible Preferred Stock

We are not obligated to pay dividends on the convertible preferred stock and no payment or adjustment will be made upon conversion for any undeclared or, subject to limited exceptions, unpaid dividends.

Quarterly dividends on the convertible preferred stock are only payable when, as and if declared by our Board or an authorized committee thereof. Our Board is not legally obligated to declare dividends, even if we have funds available for such purposes. Under Delaware law, dividends on capital stock may only be paid from “surplus” or, if there is no “surplus,” from the corporation’s net profits for the then-current or the preceding fiscal year. Further, even if adequate surplus is available to pay dividends on the convertible preferred stock, we may not have sufficient cash to pay dividends on the convertible preferred stock.

No allowance or adjustment will be made upon conversion for any undeclared or, subject to limited exceptions, unpaid dividends.

ITEM 1B. UNRESOLVED STAFF COMMENTS
None.

ITEM 3. LEGAL PROCEEDINGS

We are not a party to any material pending legal or governmental proceedings, other than ordinary routine litigation incidental to our business. While the ultimate outcome and impact of any proceeding cannot be predicted with certainty, our management believes that the resolution of any of our pending proceedings will not have a material adverse effect on our financial condition or results of operations.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

Price Range of Common Stock and Number of Holders

Our common stock is listed on the New York Stock Exchange under the symbol "REN". The following table sets forth the high and the low sale prices per share of our common stock for the twelve months ended December 31, 2017 and 2016. The closing price of the common stock on February 28, 2018, was $32.50.

	2017		2016	
Period	High	Low	High	Low
1st Quarter	$49.14	$33.29	$4.40	$2.25
2nd Quarter	$45.70	$27.34	$3.85	$2.35
3rd Quarter	$35.24	$23.64	$26.50	$2.76
4th Quarter	$33.33	$25.46	$42.34	$22.27

As of February 28, 2018, there were approximately 220 record holders of our common stock.

In June 2016 Resolute filed a certificate of amendment to its certificate of incorporation to effect the previously-announced reverse stock split of the Company's common stock, par value $0.0001 per share, at a ratio of 1-for-5 (the "Reverse Stock Split"). The certificate of amendment also reduced the number of authorized shares of common stock from 225,000,000 to 45,000,000. The Reverse Stock Split, including the certificate of amendment, was approved by stockholders at the Company's 2016 annual meeting of stockholders and by the Company's Board of Directors. All historical share amounts disclosed have been retroactively adjusted to reflect the Reverse Stock Split.

Issuer Purchases of Equity Securities

In connection with the vesting of company restricted common stock under the 2009 Long Term Performance Incentive Plan (the "Incentive Plan"), we retain shares of common stock at the election of the recipients of such awards in satisfaction of withholding tax obligations. These shares are retired by the Company.

2017	Total Number of Shares Purchased (1)(2)	Average Price Paid Per Share
March 1 – 31	84,835	$ 38.22
April 1 – 30	1,088	$ 41.76
May 1 – 31	154	$ 38.09
June 1 – 30	32	$ 40.69
July 1 – 31	166	$ 29.77
August 1 – 30	183	$ 33.60
September 1 – 30	2,947	$ 29.63
November 1 – 30	17	$ 31.12
Total	89,422	$ 37.95

(1) All shares purchased in 2017 were to offset tax withholding obligations that occur upon the vesting and delivery of outstanding common shares under the terms of the Incentive Plan.

(2) As of December 31, 2017, the maximum number of shares that may yet be purchased would not exceed the employees' portion of taxes withheld on unvested shares (537,931 common shares), outstanding stock options (918,254 options), shares available for issuance under the Incentive Plan (1,913,502 shares) and Outperformance Shares that may be earned in the future (130,444 shares).

Dividend Policy

We have not declared any cash dividends on our common stock since inception and have no plans to do so in the foreseeable future. We pay quarterly dividends on the convertible preferred stock, although we are not legally required to declare or pay such dividends. The ability of our Board of Directors to declare any dividend is subject to limits imposed by the terms of our Revolving Credit Facility and our indenture covering the Senior Notes, which currently prohibit us from paying dividends on our common stock. Our ability to pay dividends is also subject to limits imposed by Delaware law. In determining whether to declare dividends, the Board of Directors will consider the limits imposed by the Revolving Credit Facility, Senior Notes, financial condition, results of operations, working capital requirements, future prospects and other factors it considers relevant.

Stockholders Rights Plan

In May 2016 Resolute declared a dividend of one preferred share purchase right (a "Right") for each outstanding share of common stock, par value $0.0001 per share. The Rights trade with, and are inseparable from, the common stock until such time as they become exercisable on the Distribution Date (described below). The Rights are evidenced only by certificates that represent shares of common stock and not by separate certificates. New Rights will accompany any new shares of common stock we issue after May 27, 2016, until the earlier of the Distribution Date described below and the redemption or expiration of the Rights.

Each Right allows its holder to purchase from the Company one one-thousandth of a share of Series A Junior Participating Preferred Stock (a "Preferred Share") for $4.50, once the Rights become exercisable. Prior to exercise, the Right does not give its holder any dividend, voting or liquidation rights. The Rights will not be exercisable until 10 days after the public announcement that a person or group has become an "Acquiring Person" by obtaining beneficial ownership of 20% or more of our outstanding common stock, or, if earlier, 10 business days (or a later date determined by the Board before any person or group becomes an Acquiring Person) after a person or group begins a tender or exchange offer which, if completed, would result in that person or group becoming an Acquiring Person. The stockholder rights plan was approved by the Company's stockholders at the 2017 annual meeting in May 2017.

Comparison of Cumulative Return

The following graph compares the cumulative return on a $100 investment in Resolute common stock on the New York Stock Exchange over the five-year period ended December 31, 2017, to that of the cumulative return on a $100 investment in the Russell 2000 Index and the S&P 500 Energy Index for the same period. In calculating the cumulative return, reinvestment of dividends, if any, is assumed. The indices are included for comparative purpose only. This graph is not "soliciting material," is not deemed filed with the SEC and is not to be incorporated by reference in any of our filings under the Securities Act or the Exchange Act, whether made before or after the date hereof and irrespective of any general incorporation language in any such filing.

COMPARISON OF CUMULATIVE TOTAL RETURN

AMONG RESOLUTE ENERGY CORPORATION, THE RUSSELL 2000 INDEX

AND THE S&P 500 ENERGY INDEX

ITEM 6.SELECTED FINANCIAL DATA

The following table presents our selected historical financial data for each of the five years ended December 31, 2017. Future results may differ substantially from historical results because of changes in oil and gas prices, production increases or declines and other factors. This information should be read in conjunction with our consolidated financial statements and related notes and "Management's Discussion and Analysis of Financial Condition and Results of Operations" presented elsewhere in this report.

	Year Ended December 31,				
	2017	2016	2015	2014	2013
	(in thousands, except per share data)				
Statement of Operation Data:					
Revenue	$303,478	$164,478	$154,644	$329,371	$349,779
Operating expenses	259,459	255,984	931,348	442,045	483,647
Income (loss) from operations	44,019	(91,506)	(776,704)	(112,674)	(133,868)
Other income (expense)	(45,545)	(70,125)	12,071	86,684	(44,617)
Loss before income taxes	(1,526)	(161,631)	(764,633)	(25,990)	(178,485)
Income tax benefit (expense)	293	(91)	22,354	4,140	64,679
Net loss	(1,233)	(161,722)	(742,279)	(21,850)	(113,806)
Net loss available to common shareholders	(7,708)	(161,722)	(742,279)	(21,850)	(113,806)
Loss per share:					
Common stock, basic and diluted	$(0.35)	$(10.33)	$(49.55)	$(1.50)	$(8.35)
Weighted average shares outstanding:					
Common stock, basic and diluted	21,889	15,767	14,986	14,760	13,652
Selected Cash Flow Data:					
Net cash provided by operating activities	$137,232	$83,719	$69,479	$143,468	$133,328
Net cash provided by (used in) investing activities	(271,489)	(190,467)	199,583	(175,893)	(405,518)
Net cash provided by (used in) financing activities	4,930	230,540	(264,117)	36,758	271,275

	As of December 31,				
	2017	2016	2015	2014	2013
	(in thousands)				
Balance Sheet Data:					
Total assets	$641,922	$588,373	$390,983	$1,439,707	$1,468,809
Long term debt	550,727	405,975	514,995	759,942	736,671
Total liabilities	716,331	664,120	594,264	913,089	935,257
Stockholders' equity (deficit)	(74,409)	(75,747)	(203,281)	526,618	533,552

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

Overview

The following discussion and analysis should be read in conjunction with the consolidated financial statements and the related notes contained elsewhere in this report.

Resolute Energy Corporation, a Delaware corporation incorporated on July 28, 2009, is a publicly traded, independent oil and gas company with assets located in the Delaware Basin in west Texas. Our development activity is focused on our 27,100 gross (21,100 net) operated acreage, approximately 90% of which is located in what we believe to be the core of the Wolfcamp horizontal play in northern Reeves County, Texas. Our corporate strategy is to drive organic growth in reserves, production and cash flow through development of our Reeves County acreage and to pursue opportunistic acquisitions in the Delaware Basin.

We closed on the disposition of our Aneth Field Properties located in the Paradox Basin in southeast Utah on November 6, 2017. The historical results of operations of the Aneth Field Properties prior to disposition are contained in our financial position and results as of December 31, 2017 and for the twelve months ended December 31, 2017.

As of December 31, 2017, our estimated net proved reserves were approximately 53.4 MMBoe, of which approximately 49% were proved developed producing reserves ("PDP") and approximately 47% were oil. The standardized measure of our estimated net proved reserves as of December 31, 2017, was $433 million. Our future earnings and cash flow from existing operations are dependent on a variety of factors including commodity prices, exploitation and recovery activities and our ability to manage our overall cost structure at a level that allows for profitable operation.

For 2017 the Board initially approved a capital expenditure plan primarily focused on a two rig drilling program spudding 22 gross wells in the Delaware Basin. This original capital program did not contemplate the Delaware Basin Bronco Acquisition or any related capital activities. Due to the continuing efficiency of our drilling and with the closing of the Aneth Disposition, our Board approved an expansion to our 2017 capital program, which allowed us to retain the rigs and completion crews that provided these excellent results. As a result of increased drilling and completion efficiency, Resolute was able to complete drilling operations on 25 wells and had three wells drilling over year-end, while still completing and bringing on line 21 wells in these areas. Excluding the three wells that were drilling over year-end, Resolute carried six drilled but uncompleted wells ("DUCs") into 2018.

Resolute's 2018 plan includes net capital spending of $365 million to $395 million, including $350 million to $375 million in drilling and completion capital to support two rigs throughout the year, and a third rig which commenced work in late February and is expected to be released in mid-September. Additionally, the Company expects to spend an incremental $42 million to $49 million on field facilities and other corporate capital, and to receive estimated earn-out payments of $27 million to $29 million from Caprock. Overall, Resolute expects to drill 42 wells during the year and bring 38 wells on production, carry six DUCs and have two wells drilling over year-end 2018.

Each of the three rigs will be primarily pad drilling three-well stacks with all the rigs in the same spacing unit at the same time. Operations will focus in the Sandlot unit in Mustang and the Mitre/Ranger units in Appaloosa, with Wolfcamp Upper A, Lower A, and Upper B as the primary target zones. This approach to pad drilling will provide us with the opportunity to batch complete groups of up to nine wells simultaneously.

Beginning in late 2017 the Company shifted focus to building an inventory of drilled wells to batch complete. Two completions are expected in first quarter 2018, and in mid-March we will begin completing our first nine-well group. With the first nine-well group coming on line in May and another nine-well group coming on line in July we expect production growth to accelerate in the middle part of the year. Further groups of completed wells are expected to come on line throughout the remainder of the year.

This 2018 development plan was put in place based on the Company’s experience with the impact of infill drilling on well performance. In estimating its 2018 total production, Resolute believes it has fully incorporated the anticipated effects of frac interference on older wells and the expected modestly reduced production from newly drilled infill wells. In addition the Company has taken into consideration potential operational events that could reduce production further such as power outages, weather, well shut-ins and downstream gas constraints.

On February 22, 2017, we closed on the sale of our Denton and South Knowles properties in the Northwest Shelf project area in Lea County, New Mexico, for approximately $14.5 million in cash, subject to customary purchase price adjustments. The proceeds of the sale were used for general corporate purposes. As part of the sale, the Company was also no longer liable for asset retirement obligations of $3.6 million at March 31, 2017.

On April 27, 2017, Resolute Natural Resources LLC (“Resolute Southwest”) entered into a Crude Oil Connection and Dedication Agreement with Caprock Permian Crude LLC (“Caprock Crude”), an affiliate of Caprock Permian Processing LLC and Caprock Field Services LLC (collectively “Caprock”). Pursuant to the agreement, Caprock Crude has constructed the gathering systems, pipelines and other infrastructure for the gathering of crude oil from our Mustang and Appaloosa operating areas in exchange for customary fees based on the volume of crude oil produced and delivered. Resolute Southwest has agreed to dedicate and deliver all crude oil produced from its acreage in Mustang and Appaloosa to Caprock Crude for gathering for a term through July 31, 2031, coterminous with our other commercial agreements with Caprock. For the first five years of the agreement, the crude oil will be delivered to Midland Station under a joint tariff arrangement between Caprock Crude and Plains Pipeline, L.P. On April 27, 2017, Resolute Southwest also entered into a Crude Oil Purchase Contract with Plains Marketing, L.P. providing for the sale to Plains of substantially all of the crude oil produced from the Mustang and Appaloosa areas for a price equal to an indexed market price less a $1.75 differential that will cover the joint tariff payable to Caprock Crude under the Crude Oil Connection and Dedication Agreement.

On May 15, 2017, Resolute Southwest closed on a Purchase and Sale Agreement with CP Exploration II, LLC and Petrocap CPX, LLC pursuant to which Resolute Southwest acquired certain producing and undeveloped oil and gas properties in the Delaware Basin in Reeves County, Texas. The acquisition was accounted for as an asset acquisition. The Company acquired these properties for $161.3 million, which it financed substantially with proceeds received from the offering of $125 million of 8.50% Senior Notes due 2020 that closed in May 2017. The properties acquired included approximately 4,600 net acres in Reeves County, Texas, which were considered predominantly unproved, consisting of 2,187 net acres adjacent to the Company’s existing operating area in Reeves County and 2,405 net acres in southern Reeves County.

On November 6, 2017, to complete our repositioning as a pure-play Delaware Basin company, Resolute closed on a Purchase and Sale Agreement pursuant to which we sold the equity interests in Resolute Aneth, LLC, the entity which held all of Resolute’s interest in Aneth Field, and certain other assets associated with Aneth Field operations, to Elk Petroleum. Total consideration will be up to $195 million, comprised of $160 million ($150 million of which was received at closing and $10 million of which was a deposit received in the third quarter), adjusted for normal closing purchase price adjustments and up to an additional $35 million if oil prices exceed certain levels in the three years following the closing.

How We Evaluate Our Operations

Our management uses a variety of financial and operational measurements to analyze our operating performance, including but not limited to, production levels, pricing and cost trends, reserve trends, operating and general and administrative expenses, operating cash flow, Adjusted EBITDA and Credit facility EBITDA (defined below).

Production Levels, Trends and Prices. Oil and gas revenue is the result of our production multiplied by the price that we receive for that production. Because the price that we receive is highly dependent on many factors outside of our control, except to the extent that we have entered into derivative arrangements that can influence our net price either positively or negatively, production is the primary revenue driver over which we have some influence. Although we cannot greatly alter reservoir performance, we can implement exploitation activities that can increase production or diminish production declines relative to what would have been the case without intervention.

The price of oil had been trending lower June 2014 through 2016, although a modest recovery began in late 2016 and has continued intermittently in 2017. We expect that volatility to continue. Given the inherent volatility of oil prices, we plan our activities and budget based on product price assumptions that we believe to be reasonable. We use derivative contracts to provide a measure of stability to our cash flows in an environment of volatile oil and gas prices and currently have such contracts in place through 2018. These instruments limit our exposure to declines in prices, but also limit our ability to receive the benefit of price increases. Changes in the price of oil or gas will result in the recognition of a non-cash gain or loss recorded in other income or expense due to changes in the future fair value of the derivative contracts. Recognized gains or losses arise only from payments made or received on monthly settlements of derivative contracts or if a derivative contract is terminated prior to its expiration. We typically enter into derivative contracts that cover a significant portion of our estimated future oil and gas production.

Reserve Trends. We acquired our Permian Basin Properties in 2011, 2012, 2016 and 2017. Over that time we have added reserves and production principally through drilling and completion of wells in the Wolfcamp formation. We also believe that our knowledge of various domestic onshore operating areas, strong management and staff and solid industry relationships will allow us to locate, capitalize on and integrate strategic acquisition opportunities which may include acquisitions of reserves.

At December 31, 2017, we have estimated net total proved Delaware Basin reserves of 53,428 MBoe as compared to 35,390 MBoe at December 31, 2016. Net proved developed producing reserves of 13,825 MBoe were added through the drilling of sixteen previously non-proved locations, the completion of seven DUC locations and two producing wells acquired in the Delaware Basin Bronco Acquisition, along with 11,939 MBoe of net reserves added through the addition of fifteen immediate offset proved undeveloped locations. Additionally, the 2017 drilling program resulted in an addition of proved developed producing reserves of 6,046 MBoe from successful drilling of eight proved locations. Nine immediate offset proved undeveloped locations to wells drilled prior to 2017 also became economic under December 31, 2107 SEC pricing adding an additional 6,217 MBoe to proved undeveloped reserves.

Pursuant to full cost accounting rules, we perform ceiling tests each quarter on our proved oil and gas assets. We recorded non-cash impairments of the carrying value of our proved oil and gas properties of $58 million, and $705 million during 2016 and 2015, respectively, as a result of the ceiling test limitation. No impairment was recorded during 2017. If in future periods a negative factor impacts one or more of the components of the calculation, including market prices of oil and gas (based on a trailing twelve-month unweighted average of the oil and gas prices in effect on the first day of each month), differentials from posted prices, future drilling and capital plans, operating costs or expected production, we may incur full cost ceiling impairment related to our oil and gas properties in such periods.

Operating Expense. Operating expense consist of costs associated with the operation of oil and gas properties and production and ad valorem taxes. Compression, gathering, water disposal, utilities, direct labor, repair and maintenance, workovers, rental equipment, fluids and chemicals and contract services comprise the most significant portion of lease operating expense. We monitor our operating expense in relation to production amounts and the number of wells operated. Some of these expenses are relatively independent of the volume of hydrocarbons produced, but may fluctuate depending on the activities performed during a specific period. Other expenses, such as taxes and utility costs, are more directly related to production volumes or reserves. Severance taxes, for example, are charged based on production revenue and therefore are based on the product of the volumes that are sold and the related price received. Ad valorem taxes are generally based on the value of reserves. Volatility in commodity prices can also lead to changes in demand for drilling rigs, workover rigs, operating personnel and field supplies and services, which in turn can affect the costs of those goods and services.

General and Administrative Expense. We monitor our general and administrative expense carefully, attempting to balance costs against the benefits of, among other things, hiring and retaining highly qualified staff who can add value to our asset base. General and administrative expense includes, among other things, salaries and benefits, long-term incentive compensation, general corporate overhead, fees paid to independent auditors, attorneys, petroleum engineers and other professional advisors, costs associated with public company financial reporting, proxy statements and shareholder reports, investor relations activities, registrar and transfer agent fees, director and officer liability insurance costs and director compensation.

Operating Cash Flow. Operating cash flow is the cash directly derived from our oil and gas properties, before considering such things as administrative expenses and interest costs. Operating cash flow per unit of production is a measure of field efficiency, and can be compared to results obtained by operators of oil and gas properties with characteristics similar to ours in order to evaluate relative performance. Aggregate operating cash flow is a measure of our ability to sustain overhead expenses and costs related to capital structure, including interest expenses.

Adjusted EBITDA. We define Adjusted EBITDA (a non-GAAP measure) as consolidated net income adjusted to exclude interest expense, interest income, income taxes, depletion, depreciation and amortization, impairment expense, accretion of asset retirement obligation, change in fair value of derivative instruments, non-cash share-based compensation expense, non-recurring cash-settled incentive award payments and gains and losses on the sale of assets and ceiling write-down of oil and gas properties. This definition excludes the one-time cost of the Aneth Disposition and any costs related to stockholder activism.

Adjusted EBITDA is used as a supplemental liquidity or performance measure by our management and by external users of our financial statements such as investors, research analysts and others, to assess:

- our operating performance and return on capital without regard to financing methods or capital structure;
- financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- our ability to finance capital expenditures;
- the ability of our assets to generate cash sufficient to support our indebtedness and pay interest costs; and
- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

Credit facility EBITDA. Credit facility EBITDA (a non-GAAP measure) is defined under the Revolving Credit Facility as consolidated net income adjusted to exclude interest expense, interest income, income taxes, depletion, depreciation and amortization, impairment expense, accretion of asset retirement obligation, change in fair value of derivative instruments, non-cash share-based compensation expense, cash-settled incentive award payments, noncontrolling interest amounts, and customary costs and expenses incurred related to acquisitions or dispositions. Credit facility EBITDA for the four quarter period ending on December 31, 2017 is equal to EBITDA for the period beginning on July 1, 2017 and ending on December 31, 2017, multiplied by two. Credit facility EBITDA is a financial measure that we report to our lenders and is used as a gauge for compliance with a financial covenant under our Revolving Credit Facility.

Credit facility EBITDA is used as a supplemental liquidity or performance measure by our management and by external users of our financial statements such as our bank syndicate, primarily to assess the ability of our assets to generate cash sufficient to support our indebtedness and pay interest costs and to measure compliance with the covenants in our Revolving Credit Facility.

Adjusted EBITDA and Credit facility EBITDA should not be considered as alternatives to, or more meaningful than, net income available to common shareholders, net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with accounting principles generally accepted in the United States ("GAAP") as measures of operating performance, liquidity or ability to service debt obligations. Because we have borrowed money to finance our operations, interest expense is a necessary element of our costs and our ability to generate gross margins. Because we use capital assets, depletion, depreciation and amortization are also necessary elements of our costs. Therefore, any measures that exclude these elements have material limitations. To compensate for these limitations, we believe that it is important to consider both net income and net cash provided by operating activities determined under GAAP, as well as Adjusted EBITDA and Credit facility EBITDA, when evaluating our financial performance and liquidity. Adjusted EBITDA and Credit facility EBITDA exclude some, but not all, items that affect net income, operating income and net cash provided by operating activities and these measures may vary among companies. Adjusted EBITDA and Credit facility EBITDA as we calculate those numbers may not be comparable to EBITDA measures of any other company because other entities may not calculate those measures in the same manner.

Factors That Significantly Affect Our Financial Results

Revenue, cash flow from operations and future growth depend on many factors beyond our control, such as oil prices, cost of services and supplies, economic, political and regulatory developments, competition from other sources of energy and other factors described in this Form 10-K. Historical oil prices have been volatile and are expected to fluctuate widely in the future. Sustained periods of low prices for oil could materially and adversely affect our financial position, our results of operations, the quantities of oil and gas that we can economically produce, and our ability to obtain capital.

Like all businesses engaged in the exploration for and production of oil and gas, we face the challenge of natural production declines. As initial reservoir pressures are depleted, oil and gas production from a given well decreases. Thus, an oil and gas exploration and production company depletes part of its asset base with each unit of oil or gas it produces. We attempt to overcome this natural decline primarily by developing existing properties. Our future growth will depend on our ability to enhance production levels from existing reserves and to continue to add reserves in excess of production through exploration, development and acquisition. We will maintain our focus on costs necessary to produce our reserves as well as the costs necessary to add reserves through production enhancement, drilling and acquisitions. Our ability to make capital expenditures to increase production from existing reserves and to acquire more reserves is dependent on availability of capital resources, and can be limited by many factors, including the ability to obtain capital in a cost-effective manner and to obtain permits and regulatory approvals in a timely manner.

2018 Guidance

Production: For 2018, Resolute expects production to be 10,950 to 12,045 MBoe, or an average of 30,000 to 33,000 Boe per day. The Company expects average quarterly production to grow from 22,000 to 23,000 Boe per day in the first quarter to an estimated fourth quarter rate of 42,000 to 44,000 Boe per day.

Mix: Oil is expected to make up approximately 52 percent of production, while total liquids are expected to make up approximately 75 percent of production.

Lease Operating Expense: Resolute projects annual cash lease operating expense (“LOE”) for 2018 to be between $60 million and $68 million, or $5.57 per Boe at the mid-point of the range. This represents approximately 36 percent decrease in LOE per Boe compared to 2017 expenditures.

General & Administrative Expense: Resolute anticipates that annual cash general and administrative expense for 2018 will be between $30 million and $34 million, net of COPAS reimbursements and capitalization and before one-time costs associated with the Aneth Disposition, or $2.78 per Boe at the mid-point of the range, down approximately 15 percent from $3.27 per Boe in 2017. The Company's estimate of 2018 cash general and administrative expense does not include potentially material costs related to stockholder activism.

Capital Expenditures: Resolute expects capital expenditures of between $365 million and $395 million in 2018, net of estimated earn-out payments of $27 to $29 million anticipated to be received from Caprock.

Liquidity: At December 31, 2017 the Company had $30 million outstanding under its revolving credit facility. This facility currently has a $210 million borrowing base. In addition to availability under the Company's Revolving Credit Facility, Resolute believes its balance sheet provides financial flexibility and optionality to fund the 2018 development plan. Resolute expects to exit the year with a debt-to-EBITDA ratio of between 2.80x and 2.95x with further declines over a five-year outlook when using free cash flow to pay down debt.

These expectations do not include the anticipated positive impact from up to $10 million of contingency payments from the Aneth purchaser, payable in the fourth quarter of 2018, all of which has been or would be earned at today's strip, nor do they include any potential proceeds from a midstream transaction involving the Bronco properties, which is currently being explored.

Resolute will evaluate its capital expenditures in relation to its liquidity and cash flow and may adjust its activity and capital spending levels based on changes in commodity prices, the cost of goods and services, production results and other considerations.

Please read "Quantitative and Qualitative Disclosures about Market Risk – Commodity Price Risk and Derivative Arrangements" which summarizes our current derivative positions.

Stockholder Activism

On February 8, 2018, Monarch Energy Holdings LLC, an affiliate of Monarch Alternative Capital LP ("Monarch"), submitted to Resolute (i) a notice of nomination of three director candidates to stand for election to the Resolute Board at the Company's 2018 annual meeting of stockholders (the "2018 Annual Meeting") and (ii) a proposal to be made at the 2018 Annual Meeting that would repeal any provision of the Bylaws of the Company in effect at the time of the 2018 Annual Meeting that was not included in the Bylaws of the Company in effect as of February 8, 2018 and as publicly filed with the SEC prior to February 8, 2018.

The Company's Corporate Governance/Nominating Committee will review the Monarch-proposed nominees and the Board will present its recommendation with respect to the election of directors in its definitive proxy statement and White proxy card, which will be filed with the SEC and mailed to all stockholders eligible to vote at the 2018 Annual Meeting.

Responding to dissident shareholder proposals is costly and time-consuming for our Board, management and employees, and diverts the attention of our Board and senior management from the pursuit of our business strategy, which could adversely affect our results of operations and financial condition.

Results of Operations

For the purposes of management's discussion and analysis of the results of operations, management has analyzed the operational results for the twelve months ended December 31, 2017, in comparison to results for the twelve months ended December 31, 2016 and 2015.

The following table presents our sales volumes, revenues and operating expenses, and sets forth our sales prices, costs and expenses on a Boe basis for 2017, 2016 and 2015.

	Twelve Months Ended December 31,		
	2017	2016	2015
Net Sales:			
Oil (MBbl)	5,499	3,821	3,271
Gas (MMcf)	12,101	4,811	5,194
NGL (MBbl)	1,640	559	400
Total sales (MBoe)	9,156	5,182	4,536
Average daily sales (Boe/day)	25,086	14,157	12,427
Revenue:			
Revenue from oil and gas activities	$303,478	$164,478	$154,644
Operating Expenses:			
Lease operating	$79,308	$63,699	$79,393
Production and ad valorem taxes	23,351	16,270	19,985
General and administrative	48,537	32,627	31,447
General and administrative (excluding non-cash compensation expense) (1)	36,463	26,594	19,763
Restricted cash awards	16,174	34,926	1,185
Depletion, depreciation, amortization and accretion	92,089	50,462	94,338
Impairment of proved oil and gas properties	—	58,000	705,000
Other Income (Expense):			
Interest expense	$(43,449)	$(50,684)	$(64,358)
Commodity derivative instruments gain (loss)	(5,655)	(19,784)	76,492
Contingent payment derivative instrument gain	3,464	—	—
Income tax benefit (expense)	293	(91)	22,354
Average Sales Prices:			
Oil ($/Bbl)	$46.30	$38.83	$42.16
Gas ($/Mcf)	2.11	2.22	2.43
NGL ($/Bbl)	14.20	9.80	10.32
Average sales price ($/Boe, excluding commodity derivative settlements)	$33.14	$31.74	$34.09
Operating Expenses ($/Boe):			
Lease operating	$8.66	$12.29	$17.50
Production and ad valorem taxes	2.55	3.14	4.41
General and administrative	5.30	6.30	6.93
General and administrative (excluding non-cash	3.98	5.13	4.36

compensation expense)			
Restricted cash awards	1.77	6.74	0.26
Depletion, depreciation, amortization and accretion	10.06	9.74	20.80

(1) We define cash-based general and administrative expense (non-GAAP measure) as consolidated general and administrative expense adjusted to exclude non-cash share based compensation expense and one-time, non-recurring, transaction related expenses (transaction costs or fees).

Year Ended December 31, 2017, Compared to the Year Ended December 31, 2016

Revenue. Revenue from oil and gas activities increased by 85% to $303.5 million during 2017, from $164.5 million during 2016. Of the $139.0 million increase in revenue, approximately $126.2 million was attributable to increased production and $12.8 million was attributable to increased commodity pricing ($33.14 per Boe in 2017 versus $31.74 per Boe in 2016). Sales volumes increased 77% to 9,156 MBoe during 2017 as compared to 5,182 MBoe during 2016, principally as a result of production from newly drilled and completed wells.

Operating Expense. Lease operating expense includes compression, gathering, water disposal, utilities, direct labor, contract services, field office rent, production and ad valorem taxes, vehicle expenses, supervision, transportation, minor maintenance, tools and supplies, workover expenses and other customary charges. Resolute assesses lease operating expense in part by monitoring the expense in relation to production volumes and the number of wells operated.

Lease operating expense increased to $79.3 million during 2017, from $63.7 million during 2016. Conversely, on a per-unit basis, lease operating expense decreased 30% to $8.66 per Boe in 2017 compared to $12.29 per Boe in 2016. The significant decrease in per-unit operating expense is primarily due to the significant increase in production from mid-length and long-lateral horizontal wells in the Delaware Basin, which increased by a greater percentage than the associated lease operating expense.

Production and ad valorem taxes increased 44% to $23.4 million during 2017, as compared to $16.3 million during 2016 and were less on a per-unit basis compared to 2016. Production and ad valorem taxes were 7.7% of total revenue in 2017 and 9.9% of total revenue in 2016. The lower production and ad valorem taxes as a percentage of revenue in 2017 as compared to 2016 is attributable to the increase in the percentage of revenue realized in the State of Texas, which has a lower effective tax rate than the Aneth Field properties. This decrease is also the result of the timing of the assessment of ad valorem taxes, as they are assessed on January 1st of each year, based on the producing wells at that point in time and are not updated for wells that come online throughout the year.

General and administrative expense include the costs of employees and executive officers, related benefits, long-term incentive compensation, office leases, professional fees, general corporate overhead and other costs not directly associated with field operations. We monitor our general and administrative expense carefully, attempting to balance the cash effect of incurring general and administrative costs against the related benefits, with a focus on hiring and retaining highly qualified staff who can add value to our asset base.

General and administrative expense increased to $48.5 million during 2017, as compared to $32.6 million during 2016. The $15.9 million, or 49%, increase primarily resulted from one-time fees of approximately $6.5 million related to the closing of the Aneth Disposition, as well as an increase in share-based compensation expense due to a shift in 2017 from granting cash-based to equity-based long-term incentive awards and a restoration of short-term incentive compensation which had been reduced during 2016 in response to lower commodity prices. On a per-unit basis, general and administrative expense decreased 16%. Cash-based general and administrative expense was $36.5 million, or $3.98 per Boe in 2017, compared to $26.6 million, or $5.13 per Boe in 2016.

Cash-settled incentive award expense decreased to $16.2 million during 2017, as compared to $34.9 million during 2016. This decrease was primarily the result of the achievement of multiple performance targets (which primarily occurred in 2016) that are based on the Company's stock price under the performance-based awards as well as a decrease in expense related to the fair value of cash-settled stock appreciation rights under the long-term incentive program. Actual cash payments during the period were $12.1 million.

Depletion, depreciation, amortization and accretion expense increased to $92.1 million during 2017, as compared to $50.5 million during 2016 principally as a result of the 77% increase in production. On a per-unit basis depreciation, amortization and accretion expense remained relatively unchanged at $10.06 per Boe in 2017 compared to $9.74 per Boe in 2016.

Pursuant to full cost accounting rules, we perform ceiling tests each quarter on our proved oil and gas assets. The primary components affecting this calculation are commodity prices, reserve quantities, production, overall exploration and development costs and depletion expense. If the net capitalized cost of the Company's oil and gas properties subject to amortization (the "carrying value") exceeds the ceiling limitation, the excess is charged to expense.

We recorded a $58 million non-cash impairment of the carrying value of our proved oil and gas properties during 2016, as a result of the ceiling test limitation. No impairment was recorded during 2017. If in future periods a negative factor impacts one or more of the components of the calculation, including market prices of oil and gas (based on a trailing twelve-month unweighted average of the oil and gas prices in effect on the first day of each month), differentials from posted prices, future drilling and capital plans, operating costs or expected production, the Company may incur full cost ceiling impairment related to its oil and gas properties in such periods.

Other Income (Expense). All of our oil and gas derivative instruments are accounted for under mark-to-market accounting rules, which provide for the fair value of the contracts to be reflected as either an asset or a liability on the balance sheet. The change in the fair value during an accounting period is reflected in the income statement for that period. During 2017 the loss on oil and gas commodity derivatives was $5.7 million, consisting of $9.4 million of mark-to-market losses partially offset by $3.7 million of derivative settlement gains. During 2016 the loss on oil and gas commodity derivatives was $19.8 million, consisting of $107.8 million of mark-to-market losses partially offset by $88.0 million of derivative settlement gains.

Interest expense in 2017 decreased to $43.4 million from $50.7 million recorded in 2016. The $7.3 million or 14% decrease in interest expense was primarily due to increases in the amount of interest capitalized and the extinguishment of the Secured Term Loan Facility partially offset by the penalties incurred related to the repayment of the Secured Term Loan Facility, the issuance of the 8.50% Incremental Senior Notes and additional borrowings on the Revolving Credit Facility. The components of our interest expense are as follows (in thousands):

	Year Ended December 31,	
	2017	2016
8.50% senior notes	$40,759	$34,000
Secured term loan facility	3,631	14,631
Revolving credit facility	4,594	905
Amortization of deferred financing costs, senior notes premium and secured term loan facility discount	9,336	5,240
Other, net	971	37
Capitalized interest	(15,842)	(4,129)
Total interest expense	$43,449	$50,684

Approximately $9.7 million in interest expense was incurred in 2017 as a result of the extinguishment of the Secured Term Loan Facility on January 3, 2017 which included prepayment fees of $3.5 million and $6.2 million of deferred financing costs and original issue discount that were expensed as part of the extinguishment.

In conjunction with the Aneth Disposition in November 2017, Resolute is entitled to receive additional cash consideration of up to $35 million if index pricing targets, as defined in the purchase and sale agreement, are achieved at specified future dates. The contingent payment derivative instrument is accounted for under mark-to-market accounting rules, which provide for the fair value of the contracts to be reflected as either an asset or a liability on the balance sheet. The change in the fair value during an accounting period is reflected in the income statement for that period. During 2017 the gain on the contingent payment derivative was $3.5 million, consisting of $1.9 million of mark-to-market gains and $1.6 million of the derivative receivable earned pursuant to the purchase and sale agreement.

Income Tax Benefit (Expense). Income tax benefit recognized during 2017 was $0.3 million, or 19% of the loss before income taxes as compared to income tax expense in 2016 of $0.1 million, or less than 1% of the loss before income taxes. The lower than expected effective rate as compared to the statutory rate is attributable to the valuation allowance established during 2015, in addition to noncash executive compensation that is anticipated to be nondeductible for income tax purposes and to permanent differences related to share-based compensation. In addition, the 2017 effective rate was impacted by the passage of the Tax Act. The Tax Act resulted in the Company generating a deferred tax expense of $115 million primarily due to the remeasurement of our net deferred tax asset for the reduction in the U.S. statutory corporate income tax rate from a maximum 35% to a flat 21% rate. This was offset by a corresponding change in the valuation allowance on the Company’s deferred tax assets. This Tax Act also repealed the corporate AMT, causing prior year AMT credits to become refundable in future tax years. This refundable AMT credit results in a current tax benefit of $0.3 million. Based on our current interpretation and subject to release of Treasury Regulations and any other future interpretative guidance relating to the Tax Act, we believe the effects of the change in U.S. federal income tax laws incorporated herein are substantially complete. See Note 6 to our consolidated financial statements for information regarding the impact of the Tax Act on our income tax provision for the year ended December 31, 2017.

Year Ended December 31, 2016, Compared to the Year Ended December 31, 2015

Revenue. Revenue from oil and gas activities increased to $164.5 million during 2016, from $154.6 million during 2015. Of the $9.9 million increase in revenue, approximately $22.0 million was attributable to increased production, partially offset by $12.1 million of decreased commodity pricing ($31.74 per Boe in 2016 versus $34.09 per Boe in 2015). Sales volumes increased 14% to 5,182 MBoe during 2016 as compared to 4,536 MBoe during 2015. Pro forma for the 2015 property sales, 2016 production increased 50% primarily due to the successful drilling in the Delaware Basin.

Operating Expense. Lease operating expense decreased to $63.7 million during 2016, from $79.4 million during 2015. On a per-unit basis, lease operating expense decreased 30% to $12.29 per Boe in 2016 from $17.50 per Boe in 2015. The significant decrease in unit operating is due to the combination of lower costs attributable to field operating efficiencies, property sales and the significant increase in production.

Production and ad valorem taxes decreased 19% to $16.3 million during 2016, as compared to $20.0 million during 2015 and were less on a per-unit basis. Production and ad valorem taxes were 10% of total revenue in 2016 and 13% of total revenue in 2015. The lower production and ad valorem taxes as a percentage of revenue in 2016 as compared to 2015 is attributable to ad valorem taxes in Utah that are assessed as of January 1 of each year and which are less responsive to increases in prices after that date than are production taxes assessed on revenue.

General and administrative expense increased to $32.6 million during 2016, as compared to $31.4 million during 2015. The $1.2 million, or 4%, increase primarily resulted from $3.1 million in reduced corporate overhead reimbursements due to property sales, $1.4 million in increased professional fees primarily related to a terminated potential senior notes exchange and $1.3 million increase in short term incentive expense offset by decreased share based compensation. On a per-unit basis, general and administrative expense decreased 9%. Cash-based general and administrative expense was $26.6 million, or $5.13 per Boe in 2016, compared to $19.8 million, or $4.36 per Boe in 2015.

Cash-settled incentive award expense increased to $34.9 million during 2016, as compared to $1.2 million during 2015. This increase was the result of the grant of time-and performance-based restricted cash awards as well as cash-settled stock appreciation rights under the long-term incentive program and the achievement of multiple performance targets that are based on the company’s stock price. The time-based awards will vest and be expensed ratably over three years. The performance-based awards and stock appreciation rights will vest ratably over three years but their fair value will be re-measured at each period end over their ten-year lives. Actual cash payments during the period were $5.7 million.

Depletion, depreciation, amortization and accretion expense decreased to $50.5 million during 2016, as compared to $94.3 million during 2015. On a per unit basis, depreciation, amortization and accretion expense decreased to $9.74 per Boe in 2016 from $20.80 per Boe in 2015 due the significant increase in proved reserve quantities and a decrease in the 2016 amortization base resulting from the $135 million in ceiling test impairments recorded during the period from October 1, 2015, through March 31, 2016.

Pursuant to full cost accounting rules, we perform ceiling tests each quarter on our proved oil and gas assets. The primary components affecting this calculation are commodity prices, reserve quantities, production, overall exploration and development costs and depletion expense. If the net capitalized cost of the Company’s oil and gas properties subject to amortization (the “carrying value”) exceeds the ceiling limitation, the excess is charged to expense. We recorded a $58 million and $705 million non-cash impairment of the carrying value of our proved oil and gas properties during 2016 and 2015, respectively, as a result of the ceiling test limitation.

Other Income (Expense). All of our oil and gas derivative instruments are accounted for under mark-to-market accounting rules, which provide for the fair value of the contracts to be reflected as either an asset or a liability on the balance sheet. The change in the fair value during an accounting period is reflected in the income statement for that period. During 2016 the loss on oil and gas commodity derivatives was $19.8 million, consisting of $107.8 million of mark-to-market losses partially offset by $88.0 million of derivative settlement gains. During 2015 the gain on oil and gas commodity derivatives was $76.5 million, consisting of $93.2 million of derivative settlement gains offset by $16.7 million of mark-to-market losses.

Interest expense in 2016 decreased to $50.7 million from the $64.4 million recorded in 2015. The $13.7 million or 21% decrease in interest expense was primarily due to a lower level of borrowings on the Revolving Credit Facility and Secured Term Loan Facility partially offset by lower capitalized interest due to a decrease in unproved property costs with qualifying exploration activity. The components of our interest expense are as follows (in thousands):

	Year Ended December 31, 2016	2015
8.50% senior notes	$34,000	$34,000
Secured term loan facility	14,631	20,141
Revolving credit facility	905	4,498
Amortization of deferred financing costs and senior notes premium	5,240	11,578
Other, net	37	128
Capitalized interest	(4,129)	(5,987)
Total interest expense	$50,684	$64,358

Income Tax Benefit (Expense). Income tax expense recognized during 2016 was $0.1 million, or less than 1% of the loss before income taxes in 2016, as compared to income tax benefit of $22.4 million, or 3% of the loss before income taxes in 2015. The difference in the 2016 effective rate was attributable to the valuation allowance established in 2015, in addition to noncash executive compensation that is anticipated to be nondeductible for income tax purposes and to permanent differences related to share-based compensation.

Liquidity and Capital Resources

Our primary sources of liquidity have been cash generated from operations, amounts available under our Revolving Credit Facility, proceeds from the issuance of debt and equity securities and sales of oil and gas properties. For purposes of Management's Discussion and Analysis of Liquidity and Capital Resources, we have analyzed our cash flows and capital resources for the years ended December 31, 2017, 2016 and 2015.

	Year Ended December 31,		
	2017	2016	2015
	(in thousands)		
Net cash provided by operating activities	$137,232	$83,719	$69,479
Net cash provided by (used in) investing activities	(271,489)	(190,467)	199,583
Net cash provided by (used in) financing activities	4,930	230,540	(264,117)

Net cash provided by operating activities was $137.2 million during 2017 as compared to $83.7 million during 2016 and $69.5 million during 2015. The increase in net cash provided by operating activities in 2017 over 2016 was primarily due to increased revenue resulting from increased production in 2017 offset by a decrease in commodity derivative settlement gains. The increase in 2016 over 2015 was primarily due to increased revenue resulting from increased production in 2016 offset by reduced cash flow driven by 2015 property sales and increased general and administrative costs.

Net cash used in investing activities was $271.5 million during 2017 as compared to $190.5 million used during 2016 and $199.6 million provided during 2015. The primary investing activities in 2017 were cash used for capital expenditures of $306.1 million and acquisitions of $161.3 million offset by proceeds from sales of oil and gas properties of $198.2 million. Capital expenditures in 2017 consisted primarily of $295.3 million in drilling activities and infrastructure projects in the Permian Basin and $7.5 million in facility projects in Aneth Field and $3.3 million in CO_2 acquisition. Capital divestitures in 2017 included approximately $157.4 million of proceeds related to the Aneth Divestiture, $25.6 million of cash receipts related to the Earnout Agreement entered into in connection with the divestiture of the midstream assets in the Delaware Basin and $13.1 million of net proceeds primarily from the sale of the New Mexico Properties. The primary investing activity in 2016 was capital expenditures of $188.8 million. Capital expenditures in the Permian Basin consisted primarily of $95.9 in acquisitions and $111.2 million in drilling and infrastructure projects, partially offset by $35.5 million of net proceeds primarily from the sale of the Reeves County midstream assets. Capital expenditures in Aneth Field consisted of $5.9 million in CO_2 acquisition and $11.3 million in compression and facility projects. The primary investing activity in 2015 was cash provided by asset sales of $269.0 million. Capital expenditures consisted primarily of $8.9 million in CO_2 acquisition and $23.0 million in drilling activities and infrastructure projects in the Permian Basin of west Texas. Capital divestitures primarily included $42.0 million of net proceeds from the sale of the Howard and Martin County properties in the Permian Basin, $54.0 million of net proceeds from the sale of our Hilight Field properties in the Powder River Basin and $175.0 million of net proceeds from the sale of our Gardendale properties in the Midland Basin.

Net cash provided by financing activities was $4.9 million in 2017 as compared to net cash provided of $230.5 million in 2016 and net cash used of $264.1 million in 2015. The primary financing activities in 2017 were $126.9 million of proceeds received from the issuance of the Incremental Senior Notes and $20.0 million in net borrowings under the Revolving Credit Facility, offset by the repayment of $128.3 million on the Secured Term Loan. The primary financing activities in 2016 were our December 2016 common stock offering ($160.9 million in net cash provided) and our preferred stock offering in October 2016 ($59.7 million of net cash provided), partially offset by $10 million in net borrowings under the Revolving Credit Facility. The primary financing activities in 2015 were $235 million in net repayment of borrowings under the Revolving Credit Facility and $71.7 million in Secured Term Loan Facility principal payment offset by $46.5 million in net proceeds from the issuance of the Incremental Term Loans under the Secured Term Loan Facility.

If cash flow from operating activities does not meet expectations, we may reduce our expected level of capital expenditures and/or fund a portion of our capital expenditures using borrowings under our Revolving Credit Facility (if available), issuances of other debt or equity securities or from other sources, such as asset sales. There can be no assurance that needed capital will be available on acceptable terms or at all. Our ability to raise funds through the incurrence of additional indebtedness could be limited by the covenants in our Revolving Credit Facility or Senior Notes. If we are unable to obtain funds when needed or on acceptable terms, we may not be able to satisfy our obligations under our existing indebtedness, finance the capital expenditures necessary to maintain production or proved reserves or complete acquisitions that may be favorable to us.

We plan to continue our practice of hedging a significant portion of our production through the use of various commodity derivative transactions. Our existing derivative transactions have not been designated as cash flow hedges, and we anticipate that future transactions will receive similar accounting treatment. Derivative settlements usually occur within five days of the end of the month. As is typical in the oil and gas industry, however, we do not generally receive the proceeds from the sale of our oil production until the 20th day of the month following the month of production. As a result, when commodity prices increase above the fixed price in the derivative contacts, we will be required to pay the derivative counterparty the difference between the fixed price in the derivative contract and the market price before receiving the proceeds from the sale of the hedged production. If this occurs, we may use working capital or borrowings under the Revolving Credit Facility to fund our operations.

Revolving Credit Facility

In February 2017, we entered into the Third Amended and Restated Credit Agreement with a syndicate of banks led by Bank of Montreal, as Administrative Agent, Capital One, National Association, as syndication agent, and Barclays Bank PLC, ING Capital LLC and SunTrust Bank, as co-documentation agents. In connection with entering into the Revolving Credit Facility, we repaid all amounts outstanding under the Second Amended and Restated Credit Agreement by and among Resolute Energy Corporation, as Borrower, certain subsidiaries of Resolute Energy Corporation, as Guarantors, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto, as amended, and terminated that agreement.

The Revolving Credit Facility specifies a maximum borrowing base as determined by the lenders in their sole discretion. The determination of the borrowing base takes into consideration the estimated value of our oil and gas properties in accordance with the lenders' customary practices for oil and gas loans. The borrowing base is re-determined semi-annually, and the amount available for borrowing could be increased or decreased as a result of such redeterminations. Under certain circumstances, either the Company or the lenders may request an interim redetermination. The Revolving Credit Facility matures in February 2021 unless there is a maturity of material indebtedness prior to such date.

The Revolving Credit Facility includes covenants that require, among other things, that Resolute maintains a ratio of current assets to current liabilities of no less than 1.0 to 1.0 and a ratio of funded debt to EBITDA (as defined in the Revolving Credit Facility) of no more than 4.0 to 1.0. The Revolving Credit Facility also includes customary additional terms and covenants that place limitations on certain types of activities, hedging, the payment of dividends, and that require satisfaction of certain financial tests.

In October 2017, we entered into the Second Amendment to the Third Amended and Restated Credit Agreement. The Second Amendment, among other things, amended the definition of EBITDA to exclude customary transaction costs and expenses incurred in connection with any material acquisition or disposition, and provided for certain amendments to the calculation of EBITDA for purposes of the Revolving Credit Facility (providing for annualization of quarterly EBITDA through the first quarter of 2018). Additionally, the amended covenants prohibit us from entering into derivative arrangements during which such derivative arrangements are in effect for more than (i) for the first year, the greater of 85% of anticipated projected production from proved properties or 75% of our anticipated projected production from properties, (ii) for the second year, 85% of anticipated projected production from proved properties and (iii) for the period after such two year period, the greater of 75% of our anticipated projected production from proved properties or 85% of our anticipated projected production from proved developed producing properties after such two year period (not to exceed a term of 60 months for any such derivative arrangement). Furthermore, the Second Amendment reaffirmed our borrowing base at $218.8 million. Upon the consummation of the disposition of the Aneth Field Properties, our borrowing base was automatically decreased to $210 million. Lastly, the amendment provided that the borrowing base shall automatically be reduced by 25% of all unsecured indebtedness of the Company in excess of $550 million. We were in compliance with all material terms and covenants of the Revolving Credit Facility at December 31, 2017.

To the extent that the borrowing base, as adjusted from time to time, exceeds the outstanding balance, no repayments of principal are required prior to maturity. However, should the borrowing base be set at a level below the outstanding balance, we would be required to eliminate that excess within the 120 days following that determination. The Revolving Credit Facility is guaranteed by all of our subsidiaries and is collateralized by substantially all of the assets of the Company and its wholly-owned subsidiaries.

Each borrowing under the Revolving Credit Facility accrues interest at either (a) the London Interbank Offered Rate ("LIBOR"), plus a margin that ranges from 3.0% to 4.0% or (b) the Alternative Base Rate defined as the greater of (i) the Administrative Agent's Prime Rate (ii) the Federal Funds Effective Rate plus 0.5% or (iii) an adjusted LIBOR, plus a margin for the Alternate Base Rate that ranges from 2.0% to 3.0%. Each such margin is based on the level of utilization under the borrowing base.

Resolute Energy Corporation, the stand-alone parent entity, has insignificant independent assets and no operations. There are no restrictions on our ability to obtain cash dividends or other distributions of funds from our subsidiaries, except those imposed by applicable law.

Secured Term Loan Agreement

In December 2014 we entered into a second lien Secured Term Loan Agreement with Bank of Montreal, as administrative agent, and the lenders party thereto, pursuant to which we borrowed $150 million. In May 2015 Resolute and certain of its subsidiaries, as guarantors, entered into an Amendment to the Secured Term Loan Agreement and Increased Facility Activation Notice-Incremental Term Loans with Bank of Montreal, as administrative agent, and the lenders party thereto, pursuant to which we borrowed an additional $50 million of Incremental Term Loans under its Secured Term Loan Facility.

In December 2015, we retired $70 million of the amount outstanding under the Secured Term Loan Facility following the sale of certain properties in the Midland Basin in accordance with mandatory prepayment provisions stipulated in the Secured Term Loan Facility.

In January 2017, we paid approximately $132 million constituting all amounts due under the Secured Term Loan Facility (including prepayment fees of $3.5 million), with a portion of the proceeds from the common stock offering that closed on December 23, 2016. In addition, $6.2 million of deferred financing costs and original issue discount were expensed as part of the extinguishment. The Secured Term Loan Facility was terminated in connection with the repayment.

Senior Notes

In 2012 we consummated two private placements of senior notes with principal totaling $400 million (the “Original Senior Notes”). The original Senior Notes are due May 1, 2020, and bear an annual interest rate of 8.50% with the interest on the notes payable semiannually in cash on May and November 1 of each year.

In May 2017, we consummated a private placement of senior notes totaling $125 million aggregate principal amount of the Company’s 8.50% Incremental Senior Notes due 2020. The Incremental Senior Notes constituted an additional issuance of notes under the same indenture as the Original Senior Notes that were previously issued (collectively referred to as the “Senior Notes”). The net proceeds of the offering of the Incremental Senior Notes, after reflecting the purchasers’ discounts and commissions, and estimated offering expenses, were approximately $125.1 million. The closing of the Incremental Senior Notes occurred on May 12, 2017.

The Senior Notes were issued under an Indenture (the “Indenture”) among the Company and all of the Company’s subsidiaries (the “Guarantors”), each of which is 100% owned by the Company, in a private transaction not subject to the registration requirements of the Securities Act of 1933. In March 2013 and July 2017, we registered the exchange of the Original Senior Notes and the Incremental Senior Notes, respectively, with the Securities and Exchange Commission pursuant to the registration statements on Form S-4 that enabled holders of the Senior Notes to exchange the privately placed Senior Notes for registered Senior Notes with substantially identical terms. The Indenture contains affirmative and negative covenants that, among other things, limit our and the Guarantors’ ability to make investments, incur additional indebtedness or issue certain types of preferred stock, create liens, sell assets, enter into agreements that restrict dividends or other payments by restricted subsidiaries, consolidate, merge or transfer all or substantially all of our assets, engage in transactions with our affiliates, pay dividends or make other distributions on capital stock or prepay subordinated indebtedness and create unrestricted subsidiaries. The Indenture also contains customary events of default. Upon occurrence of events of default arising from certain events of bankruptcy or insolvency, the Senior Notes shall become due and payable immediately without any declaration or other act of the trustee or the holders of the Senior Notes. Upon the occurrence of certain other events of default, the trustee or the holders of the Senior Notes may declare all outstanding Senior Notes to be due and payable immediately. We were in compliance with all material terms and covenants under our Senior Notes as of December 31, 2017.

The Senior Notes are general unsecured senior obligations of the Company and guaranteed on a senior unsecured basis by the Guarantors. The Senior Notes rank equally in right of payment with all existing and future senior indebtedness of the Company, will be subordinated in right of payment to all existing and future senior secured indebtedness of the Guarantors, will rank senior in right of payment to any future subordinated indebtedness of the Company and will be fully and unconditionally guaranteed by the Guarantors on a senior basis.

The Senior Notes are redeemable by us on not less than 30 or more than 60 days prior notice, at a redemption of 102.125% reducing to 100.0% at May 1, 2018. If a change of control occurs, each holder of the Senior Notes will have the right to require that we purchase all of such holder’s Senior Notes in an amount equal to 101% of the principal of such Senior Notes, plus accrued and unpaid interest, if any, to the date of the purchase.

Preferred Stock

In October 2016, the Company entered into a Purchase Agreement with BMO Capital Markets Corp. ("Initial Purchaser"), pursuant to which the Company agreed to issue and sell to Initial Purchaser 62,500 shares of the Company's 8 % Series B Cumulative Perpetual Convertible Preferred Stock, par value $0.0001 per share (the "Convertible Preferred Stock"), which includes 7,500 additional shares of Convertible Preferred Stock issued pursuant to the exercise of the Initial Purchaser's over-allotment option for an aggregate net consideration of $60 million, before offering expenses.

Each holder has the right at any time, at its option, to convert, any or all of such holder's shares of Convertible Preferred Stock at an initial conversion rate of 33.8616 shares of fully paid and nonassessable shares of Common Stock, per share of Convertible Preferred Stock. Additionally, at any time on or after October 15, 2021, the Company shall have the right, at its option, to elect to cause all, and not part, of the outstanding shares of Convertible Preferred Stock to be automatically converted into that number of shares of Common Stock for each share of Convertible Preferred Stock equal to the conversion rate in effect on the mandatory conversion date as such terms are defined in the Certificate of Designation.

During 2017, preferred dividends of $5.2 million were paid. A preferred dividend of $1.3 million was declared on December 19, 2017, and paid on January 16, 2018, to holders of record at the close of business on January 1, 2018.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet financing arrangements other than operating leases and have not guaranteed any debt or commitments of other entities or are party to any options on non-financial assets.

Contractual Obligations

We have the following contractual obligations and commitments as of December 31, 2017:

	Less than 1 year	1-3 Years	3–5 Years	More Than 5 Years	Total [3]
	(in thousands)				
Obligations:					
Term loans and related interest	$44,625	$591,938	$—	$ —	$636,563
Revolving credit facility [1]	30,000	—	—	—	30,000
Office and equipment leases	1,855	2,690	1,858	—	6,403
Vehicle leases	303	471	264	—	1,038
Construction purchase obligations [2]	2,605	—	—	—	2,605
Total	$79,388	$595,099	$2,122	$ —	$676,609

(1) Represents the outstanding principal amount under our Revolving Credit Facility. This table does not include future commitment fees, interest expense or other fees because the Revolving Credit Facility is a floating rate instrument, and we cannot determine with accuracy the timing of future loan advances, repayments or future interest rates to be charged.

(2) Represents purchase commitments in effect at December 31, 2017, related to construction projects in the Permian Basin Properties.

(3) Total contractually obligated payment commitments do not include the anticipated settlement of derivative contracts, obligations to taxing authorities or amounts relating to our asset retirement obligations, which include plugging and abandonment obligations, due to the uncertainty surrounding the ultimate settlement amounts and timing of these obligations.

Critical Accounting Policies

The discussion and analysis of our financial condition and results of operations is based upon the consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of these financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenue and expenses and related disclosure of contingent assets and liabilities. The application of accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate estimates and assumptions on a regular basis. We base estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ, perhaps materially, from these estimates and assumptions used in the preparation of our financial statements. Provided below is an expanded discussion of our most significant accounting policies, estimates and judgments used in the preparation of the financial statements.

Full Cost Accounting. We use the full cost method of accounting for oil and gas operations. All costs incurred in the acquisition, exploration and development of properties, including costs of unsuccessful exploration, costs of surrendered and abandoned leaseholds, delay lease rentals and the fair value of estimated future costs of site restoration, dismantlement and abandonment activities, improved recovery systems and a portion of general and administrative and operating expenses are capitalized on a country wide basis (the “Cost Center”). No gain or loss is recognized upon the sale or abandonment of undeveloped or producing oil and gas properties unless the sale represents a significant portion of oil and gas properties and the gain significantly alters the relationship between capitalized costs and proved oil reserves of the Cost Center.

In Aneth Field (disposed of in November 2017), we conducted tertiary recovery projects on a portion of our oil and gas properties in order to recover additional hydrocarbons that are not recoverable from primary or secondary recovery methods. Under the full cost method, all development costs were capitalized at the time incurred. Development costs included charges associated with access to and preparation of well locations, drilling and equipping development wells, test wells, and service wells including injection wells; acquiring, constructing, and installing production facilities and providing for improved recovery systems. Improved recovery systems include all related facility development costs and the cost of the acquisition of tertiary injectants, primarily purchased CO_2. The development cost related to CO_2 purchases were incurred solely for the purpose of gaining access to incremental reserves not otherwise recoverable. The accumulation of injected CO_2, in combination with additional purchased and recycled CO_2, provided future economic value over the life of the project.

In contrast, other costs related to the daily operation of the improved recovery systems were considered production costs and are expensed as incurred. These costs included, but are not limited to, costs incurred to maintain reservoir pressure, compression, electricity, separation, and re-injection of recovered CO_2 and water.

Capitalized general and administrative and operating costs include salaries, employee benefits, costs of consulting services and other specifically identifiable capital costs and do not include costs related to production operations, general corporate overhead or similar activities.

Investments in unproved properties are not depleted, pending determination of the existence of proved reserves. Unproved properties are periodically evaluated for impairment. Unproved properties whose costs are individually significant are assessed individually by considering the primary lease terms of the properties, the holding period of the properties, and geographic and geologic data obtained relating to the properties. Properties are grouped for purposes of assessing impairment when it is not practicable to assess the amount of impairment of properties on an individual basis. The amount of impairment assessed is added to the costs to be amortized.

Depletion and amortization of oil and gas properties is computed on the unit-of-production method based on proved reserves. Amortizable costs include estimates of asset retirement obligations and future development costs of proved reserves, including, but not limited to, costs to drill and equip development wells and constructing and installing production and processing facilities.

Pursuant to full cost accounting rules, we must perform a ceiling test each quarter on our proved oil and gas assets. The ceiling test provides that capitalized costs less related accumulated depletion and deferred income taxes for each Cost Center may not exceed the sum of (1) the present value of future net revenue from estimated production of proved oil and gas reserves using current prices, excluding the future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, and a discount factor of 10%; plus (2) the cost of properties not being amortized, if any; plus (3) the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; less (4) income tax effects related to differences in the book and tax basis of oil and gas properties. Should the net capitalized costs for a Cost Center exceed the sum of the components noted above, an impairment charge would be recognized to the extent of the excess capitalized costs.

The quarterly ceiling test is primarily impacted by commodity prices, changes in estimated reserve quantities, reserves produced, overall exploration and development costs, depletion expense, and deferred taxes. If pricing conditions decline, or if there is a negative impact on one or more of the other components of the calculation, we may incur full cost ceiling test impairments in future quarters. The calculated ceiling limitation is not intended to be indicative of the fair market value of our proved reserves or future results. Impairment charges do not affect cash flow from operating activities, but do adversely affect our net income and various components of our balance sheet. Any impairment of oil and gas properties is not reversible at a later date.

Oil and Gas Reserve Quantities. Our estimate of proved reserves is based on the quantities of oil and gas that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating, economic parameters, and government regulation. Reserves and their relation to estimated future net cash flows affect our depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserves estimates. We prepare reserves estimates, and the projected cash flows derived from these reserves estimates, in accordance with SEC and FASB guidelines. The accuracy of our reserves estimates is a function of many factors including but not limited to the following: the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions and the judgments of the individuals preparing the estimates. Our proved reserves estimates are a function of many assumptions, any or all of which could deviate significantly from actual results. As such, reserves estimates may vary materially from the ultimate quantities of oil, gas and NGL eventually recovered.

Business Combinations and Asset Acquisitions. We account for all business combinations using the acquisition method which involves the use of significant judgment. Under the acquisition method of accounting, a business combination is accounted for based on the fair value of the consideration given. The assets and liabilities acquired are measured at fair value and the purchase price is allocated to the assets and liabilities based on these fair values. The excess of the cost of an acquisition, if any, over the fair value of the assets acquired and liabilities assumed is recognized as goodwill. The excess of the fair value of assets acquired and liabilities assumed over the cost of an acquisition, if any, is recognized immediately in earnings as a gain. Determining the fair values of the assets and liabilities acquired involves the use of judgment since fair values are not always readily determinable. Different techniques may be used to determine fair values, including market prices (where available), appraisals, comparisons to transactions for similar assets and liabilities and the present value of estimated future cash flows, among others.

Recent Accounting Pronouncements

In January 2017 the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2017-01, Business Combinations (Topic 805): Clarifying the Definition of a Business, which clarifies the definition of a business to assist entities with evaluating when a set of transferred assets and activities is deemed to be a business. Determining whether a transferred set constitutes a business is important because the accounting for a business combination differs from that of an asset acquisition. The definition of a business also affects the accounting for dispositions. Under the new standard, when substantially all of the fair value of assets acquired is concentrated in a single asset, or a group of similar assets, the assets acquired would not represent a business and business combination accounting would not be required. Early adoption is permitted. The Company elected to early adopt this standard in the second quarter of 2017.

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2014-09, Revenue from Contracts with Customers (Topic 606), which is effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period. The new revenue standard provides a five-step analysis of transactions to determine when and how revenue is recognized. The core principle of the guidance is that a company should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The guidance in this update supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, and most industry-specific guidance throughout the Industry Topics of the Codification. Entities can choose to adopt the standard using either the full retrospective approach or a modified retrospective approach. We will adopt the standard effective January 1, 2018, utilizing the modified retrospective approach, which will be applied to contracts that were not completed as of January 1, 2018. During 2017, the Company completed its analysis of the impact of the standard on its contract types, and it does not believe that the adoption of ASU 2014-09 and ASU 2016-12 have material impact on its financial results. The Company has also modified current processes and controls to apply the requirements of the new standard. We do not believe such modifications are material to our internal controls over financial reporting. Additionally, we do not believe that adoption of the standard will impact our operational strategies and financial results.

In February 2016, the FASB issued ASU 2016-02, Leases (Topic 842), which requires lessees to present nearly all leasing arrangements on the balance sheet as liabilities along with a corresponding right-of-use asset. The ASU will replace most existing lease guidance in GAAP when it becomes effective. The new standard becomes effective for the Company on January 1, 2019. Although early application is permitted, the Company does not plan to early adopt the ASU. The standard requires the use of the modified retrospective transition method. The Company is evaluating the effect that ASU 2016-02 will have on its consolidated financial statements and related disclosures. Currently, the Company is evaluating the standard's applicability to our various contractual arrangements. We believe that adoption of the standard will result in increases to our assets and liabilities on our consolidated balance sheet. However, we have not yet determined the extent of the adjustments that will be required upon implementation of the standard. We continue to monitor relevant industry guidance regarding the implementation of ASU 2016-02 and will adjust our implementation strategies as necessary. We are in the process of evaluating the potential impact of adopting the new standard.

ITEM 7A.QUANTITIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk and Derivative Arrangements

Our major market risk exposure is in the pricing applicable to oil and gas production. Realized pricing on our unhedged volumes of production is primarily driven by the spot market prices applicable to oil production and the prevailing price for gas. Oil and gas prices have been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for unhedged production depend on many factors outside of our control.

We employ derivative instruments such as swaps, puts, calls, collars and other such agreements. The purpose of these instruments is to manage our exposure to commodity price risk in order to provide a measure of stability to our cash flows in an environment of volatile oil and gas prices.

Under the terms of our Revolving Credit Agreement, as amended on October 18, 2017, the form of derivative instruments to be entered into is at our discretion, but they are not to exceed (i) for the first year, the greater of 85% of our anticipated production from proved properties, or 75% of our anticipated projected production from properties (ii) for the second year, 85% of anticipated projected production from proved properties and (iii) for the period after such two year period, the greater of 75% of our anticipated production from proved properties or 85% of our anticipated production from proved developed producing properties after such two year period, utilizing economic parameters specified in our credit agreement, including escalated prices and costs.

By removing the price volatility from a significant portion of our oil and gas production, we have mitigated, but not eliminated, the potential effects of volatile prices on cash flow from operations for the periods hedged. While mitigating negative effects of falling commodity prices, certain of these derivative contracts also limit the benefits we would receive from increases in commodity prices. It is our policy to enter into derivative contracts only with counterparties that are major, creditworthy financial institutions deemed by management as competent and competitive market makers.

Our management has determined that the benefit of cash flow hedge accounting, which may allow for our derivative instruments to be reflected as cash flow hedges in other comprehensive income, is not commensurate with the administrative burden required to support that treatment.

Derivative instruments are recognized on the balance sheet as either assets or liabilities measured at fair value. We mark our derivative instruments to fair value on the consolidated balance sheets and recognize the changes in fair market value in earnings. As of December 31, 2017, the fair value of our commodity derivatives was a net liability of $21.3 million.

The following table represents our commodity swap contracts as of December 31, 2017:

	Oil (NYMEX WTI)		
Remaining Term	Bbl per Day	Weighted Average Swap Price per Bbl	Fair Value of Asset (Liability) (in thousands)

Jan – Dec 2018	3,744	$ 51.10	$ (11,288)

The following table represents our three-way commodity collar contracts as of December 31, 2017:

Oil (NYMEX WTI)					
Remaining Term	Bbl per Day	Weighted Average Short Put Price per Bbl	Weighted Average Floor Price per Bbl	Weighted Average Ceiling Price per Bbl	Fair Value of Asset (Liability) (in thousands)
Jan – Dec 2018	3,252	$ 40.15	$ 49.38	$ 54.19	$ (7,117)

The following represents our commodity option contracts as of December 31, 2017:

Oil (NYMEX WTI)			
Remaining Term	Bbl per Day	Weighted Average Sold Call Price per Bbl	Fair Value of Asset (Liability) (in thousands)
Jan – Dec 2018	1,100	$ 55.00	(2,417)
Jan – Dec 2019	1,100	$ 62.85	(990)

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The following represents our basis swap contract as of December 31, 2017:

Gas (Permian Basin El Paso)			
Remaining Term	MMBtu per Day	Weighted Average Price Differential per MMBtu	Fair Value of Asset (Liability) (in thousands)
Jan – Dec 2018	18,000	$ 0.688	526

Subsequent to December 31, 2017, we entered into additional commodity derivative contracts as summarized below:

Oil (NYMEX WTI)		
Bought Call	Bbl per Day	Bought Call Price
Feb – May 2018	1,100	$55.00

Oil (NYMEX WTI)		
Sold Call	Bbl per Day	Sold Call Price
Jan – Dec 2019	1,330	$65.00

Interest Rate Risk

At December 31, 2017, we had $30 million of outstanding debt under the Revolving Credit Facility. Interest is calculated under the terms of the agreement based principally on a LIBOR spread. A 10% increase in LIBOR would result in an increase of less than $0.1 million in annual interest expense. We do not currently have any derivative arrangements to protect against fluctuations in interest rates applicable to our outstanding indebtedness.

Credit Risk and Contingent Features in Derivative Instruments

We are exposed to credit risk to the extent of nonperformance by the counterparties in the commodity derivative contracts discussed above. All counterparties are current lenders under our Revolving Credit Facility. For these contracts, we are not required to provide any credit support to our counterparties other than cross collateralization with the properties securing the Revolving Credit Facility. Our derivative contracts are documented with industry standard contracts known as a Schedule to the Master Agreement and International Swaps and Derivative Association, Inc. Master Agreement (“ISDA”). Typical terms for the ISDAs include credit support requirements, cross default provisions, termination events, and set-off provisions. We have set-off provisions with our Revolving Credit Facility lenders that, in the event of counterparty default, allow us to set-off amounts owed under the Revolving Credit Facility or other general obligations against amounts owed for derivative contract liabilities.

Resolute is exposed to credit risk to the extent of nonperformance by the buyer in the contingent payment derivative discussed in “Results of Operations – Year Ended December 31, 2017 compared to the Year Ended December 31, 2016 - Other Income (Expense)”. The buyer is contractually obligated to pay Resolute the contingent payments pursuant to the purchase and sale agreement.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The information required by this item is included in “Item 15. Exhibits, Financial Statement Schedules”.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Attached as exhibits to this report are certifications of our CEO and CFO required pursuant to Rule 13a-14 under the Exchange Act. This section includes information concerning the controls and procedures evaluation referred to in the certifications. Included in this report is the report of KPMG LLP, our independent registered public accounting firm, regarding its audit of our internal control over financial reporting. This section should be read in conjunction with the certifications and the KPMG LLP report for a more complete understanding of the topics presented.

Evaluation of Disclosure Controls and Procedures. We conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) as of December 31, 2017. This evaluation was conducted under the supervision and with the participation of management, including our CEO and CFO. Based on this evaluation, our CEO and CFO have concluded that as of December 31, 2017, our disclosure controls and procedures were effective to provide reasonable assurance that the information required to be disclosed by us in reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified by the rules and forms of the SEC. We also concluded that our disclosure controls and procedures are effective to provide reasonable assurance that information required to be disclosed in the reports filed or submitted under the Exchange Act is accumulated and communicated to our management, including our CEO and CFO, to allow timely decisions regarding disclosure.

Management's Annual Report on Internal Control over Financial Reporting. Management is responsible for establishing and maintaining adequate internal controls over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act). Management assessed our internal control over financial reporting as of December 31, 2017, and has concluded that the Company maintained effective internal control over financial reporting as of December 31, 2017. This assessment was based on criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Changes in Internal Control over Financial Reporting. There have been no significant changes in our internal control over financial reporting during the most recently completed fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information relating to this item will be included in an amendment to this report or in the proxy statement for our 2018 annual stockholders' meeting and is incorporated by reference in this report.

ITEM 11. EXECUTIVE COMPENSATION

Information relating to this item will be included in an amendment to this report or in the proxy statement for our 2018 annual stockholders' meeting and is incorporated by reference in this report.

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

Information relating to this item will be included in an amendment to this report or in the proxy statement for our 2018 annual stockholders' meeting and is incorporated by reference in this report.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Information relating to this item will be included in an amendment to this report or in the proxy statement for our 2018 annual stockholders' meeting and is incorporated by reference in this report.

ITEM 14. PRINCIPAL ACCOUNTING FEE AND SERVICES

Information relating to this item will be included in an amendment to this report or in the proxy statement for our 2018 annual stockholders' meeting and is incorporated by reference in this report.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

See "Index to Consolidated Financial Statements" on page F-1.

ITEM 16. Form 10-K Summary

None.

Exhibit Number	Description of Exhibits
2.1†	Purchase and IPO Reorganization Agreement, dated as of August 2, 2009, among Hicks Acquisition Company I, Inc., Resolute Energy Corporation, Resolute Subsidiary Corporation., Resolute Holdings, LLC, Resolute Holdings Sub, LLC, Resolute Aneth, LLC and HH-HACI, L.P., (incorporated by reference to Annex A to the Registration Statement on Form S-4 filed with the SEC on August 6, 2009 (File. No 33-161076)("Initial S-4")).
2.2	Letter Agreement amending Purchase and IPO Reorganization Agreement, dated as of September 9, 2009, among Hicks Acquisition Company I, Inc., Resolute Energy Corporation, Resolute Subsidiary Corporation., Resolute Holdings, LLC, Resolute Holdings Sub, LLC, Resolute Aneth, LLC and HH-HACI, L.P., (incorporated by reference to Annex A to the Initial S-4).
2.3†	Purchase and Sale Agreement between Exxon Mobil Corporation, ExxonMobil Oil Corporation, Mobil Exploration and Producing North America Inc., Mobil Producing Texas & New Mexico Inc. and Mobil Exploration & Producing U.S. Inc. and Resolute Aneth, LLC — 75% and Navajo Nation Oil and Gas Company — 25% dated January 1, 2005 (incorporated by reference to Exhibit 2.2 to the Initial S-4).
2.4†	Asset Sale Agreement Aneth Unit, Ratherford Unit and McElmo Creek Unit, San Juan County, Utah between Chevron U.S.A. Inc. (as seller) and Resolute Natural Resources Company and Navajo Nation Oil and Gas Company, Inc. (as buyer) dated October 22, 2004 (incorporated by reference to Exhibit 2.3 to the Initial S-4).
2.5†	Stock Purchase Agreement dated June 24, 2008, between Primary Natural Resources, Inc. (as seller) and Resolute Acquisition Company, LLC (as buyer) (incorporated by reference to Exhibit 2.4 to the Initial S-4).
2.6†	Purchase and Sale Agreement between Celero Energy II, LP and Caprock Land & Cattle, LLC, as sellers, Resolute Natural Resources Southwest, LLC, as buyer, and Resolute Energy Corporation, as guarantor, dated December 1, 2012 (incorporated by reference to Exhibit 2.1 to the current report on Form 8-K filed on December 5, 2012).
2.6.1	Amendment to Purchase and Sale Agreement, by and among Celero Energy II, LP and Caprock Land & Cattle, LLC, as Sellers, Resolute Natural Resources Southwest, LLC, as Buyer, and Resolute Energy Corporation, as Guarantor, dated December 21, 2012 (incorporated by reference to Exhibit 2.1 to the current report on Form 8-K filed on December 26, 2012).
2.7†	Purchase, Sale and Option Agreement dated December 28, 2012, by and among RSP Permian LLC, Wallace Family Partnership, LP, and Ted Collins, Jr., as Sellers, and Resolute Natural Resources Southwest, LLC, as Buyer (incorporated by reference to Exhibit 2.1 to the current report on Form 8-K filed on December 31, 2012).

2.8†	Purchase and Sale Agreement dated November 19, 2015, by and between Resolute Natural Resources Southwest, LLC, as seller and Independence Resources Holdings, LLC, as buyer (incorporated by reference to Exhibit 2.1 to the Form 8-K filed on December 29, 2015 and amended on March 8, 2016).
2.9†	Purchase and Sale Agreement, dated October 4, 2016, among Resolute Energy Corporation, Resolute Natural Resources Southwest, LLC and Firewheel Energy, LLC (incorporated by reference to Exhibit 2.1 to the Form 8-K filed on October 7, 2016).
2.10†	Purchase and Sale Agreement, dated March 3, 2017, among Resolute Natural Resources Southwest, LLC, as buyer, and CP Exploration II, LLC and Petrocap CPX, LLC, as sellers (incorporated by reference to Exhibit 2.1 to the current report on Form 10-Q filed on May 3, 2017).
2.11†	Membership Interest and Asset Purchase Agreement, dated September 14, 2017, among Resolute Energy Corporation, Hicks Acquisition Company I, Inc. and Resolute Natural Resources Company, LLC, as sellers, Resolute Aneth, LLC as the Company and Elk Petroleum Aneth, LLC, as buyer, and Elk Petroleum Limited, as Parent Guarantor (incorporated by reference to Exhibit 2.1 to the current report on Form 10-Q filed on November 6, 2017).
2.12†	First Amendment to Membership Interest and Asset Purchase Agreement dated November 6, 2017 by and among Resolute Energy Corporation, Hicks Acquisition Company I. Inc., and Resolute Natural Resources Company, LLC as sellers, Resolute Aneth, LLC as the Company, and Elk Petroleum Aneth, LLC as Buyer and Elk Petroleum Limited as Parent Guarantor (incorporated by reference to Exhibit 2.1 to the current report on Form 8-K filed on November 7, 2017).
2.13†	Purchase and Sale Agreement dated January 17, 2017, by and between Resolute Natural Resources Southwest, LLC, as seller and Wishbone Texas Operating Company LLC, as buyer (incorporated by reference as Exhibit 10.1 to the current report on Form 8-K filed on February 23, 2017).

Exhibit Number	Description of Exhibits
3.1	Amended and Restated Certificate of Incorporation of Resolute Energy Corporation, filed September 25, 2009 (incorporated by reference to Exhibit 3.1 to the Annual Report on Form 10-K of Resolute Energy Corporation filed on March 30, 2010).
3.2	Amended and Restated Bylaws of Resolute Energy Corporation (incorporated by reference to Exhibit 3.2 to the Annual Report on Form 10-K of Resolute Energy Corporation filed on March 30, 2010).
3.3	Certificate of Designation of Series A Junior Participating Preferred Stock (incorporated by reference to Exhibit 3.1 to the current report on Form 8-K filed on May 17, 2016).
3.4	Certificate of Amendment to the Amended and Restated Certificate of Incorporation of Resolute Energy Corporation, as filed with the Delaware Secretary of State on June 7, 2016 (incorporated by reference to Exhibit 3.1 to the current report on Form 8-K filed on June 7, 2016).
3.5	Certificate of Designations of 8 % Series B Cumulative Perpetual Convertible Preferred Stock, filed with the Secretary of State of the State of Delaware and effective October 7, 2016 (incorporated by reference to Exhibit 3.1 to the Form 8-K filed on October 7, 2016).
4.1	Registration Rights Agreement dated September 25, 2009, among Resolute Energy Corporation and certain holders (incorporated by reference as Exhibit 4.4 to Amendment No.2 to the Initial S-4 filed on September 8, 2009).
4.2	Indenture, dated April 25, 2012, among Resolute Energy Corporation, the Guarantors named therein and U.S. Bank National Association, as Trustee, relating to the 8.50% Senior Notes due 2020 (incorporated by reference to Exhibit 4.1 to the current report on Form 8-K filed on April 26, 2012).
4.3	Registration Rights Agreement, dated April 25, 2012, among Resolute Energy Corporation, the Guarantors, and the Purchase relating to the 8.50% Senior Notes due 2020 (incorporated by reference to Exhibit 10.2 to the current report on Form 8-K filed on April 26, 2012).
4.4	Registration Rights Agreement, dated December 10, 2012, among Resolute Energy Corporation, the Guarantors, and the Purchase relating to the 8.50% Senior Notes due 2020 (incorporated by reference to Exhibit 10.2 to the current report on Form 8-K filed on December 11, 2012).
4.5	Registration Rights agreement dated May 29, 2013, by and among Resolute Energy Corporation, a Delaware corporation, and SPO Advisory Partners, L.P., San Francisco Partners, L.P. and Phoebe Snow Foundation,

Inc. (incorporated by reference as Exhibit 10.1 to the current report on Form 8-K filed on May 31, 2013).

4.6	Rights Agreement, dated as of May 17, 2016, between Resolute Energy Corporation and Continental Stock Transfer & Trust Company, which includes the form of Right Certificate as Exhibit B and the Summary of Rights to Purchase Preferred Shares as Exhibit C (incorporated by reference to Exhibit 4.1 to the current report on Form 8-K filed on May 17, 2016).
4.7	Registration Rights Agreement, dated October 4, 2016, between Resolute Energy Corporation and Firewheel Energy, LLC (incorporated by reference to Exhibit 10.2 to the Form 8-K filed on October 7, 2016).
4.8	Supplemental Indenture dated May 12, 2017, among Resolute Energy Corporation, as Issuer, and Delaware Trust Company, as Trustee, relating to the 8.5% Senior Notes due 2020 (incorporated by reference to Exhibit 4.1 to the current report on Form 8-K filed on May 12, 2017).
4.9	Purchase Agreement dated May 9, 2017, among Resolute Energy Corporation and BMO Capital Markets Corp., relating to the 8.5% Senior Notes due 2020 (incorporation by reference to Exhibit 10.1 to the current report on Form 8-K filed on May 12, 2017).
4.10	Registration Rights Agreement, dated May 12, 2017, among Resolute Energy Corporation, the Initial Guarantors, and BMO Capital Markets Corp. and Goldman Sachs & Co. LLC, as the Initial Purchasers, relating to the 8.5% Senior Notes due 2020 (incorporated by reference to Exhibit 10.2 to the current report on Form 8-K filed on May 12, 2017).
10.1	Second Amended and Restated Credit Agreement dated March 30, 2010, between Resolute Energy Corporation as Borrower and certain of its Subsidiaries as Guarantors, Wells Fargo Bank, National Association, as Administrative Agent, Bank of Montreal as Syndication Agent, Deutsche Bank Securities Inc., UBS Securities LLC and Union Bank, N.A. as Co-Documentation Agents, and The Lenders Party Thereto, Wells Fargo Securities, LLC and BMO Capital Markets as Joint Bookrunners and Joint Lead Arrangers (incorporated by reference to Exhibit 10.1 to the Annual Report on Form 10-K of Resolute Energy Corporation filed on March 30, 2010).

Exhibit Number	Description of Exhibits
10.1.1	First Amendment to Second Amended and Restated Credit Agreement, dated as of April 18, 2011, between Resolute Energy Corporation as Borrower, Wells Fargo Bank, National Association, as Administrative Agent, and the Lenders party thereto (incorporated by reference as Exhibit 10.1 to the current report on Form 8-K filed on April 16, 2012).
10.1.2	Second Amendment to Second Amended and Restated Credit Agreement, dated as of April 25, 2011, between Resolute Energy Corporation as Borrower, Wells Fargo Bank, National Association, as Administrative Agent, and the Lenders party thereto (incorporated by reference as Exhibit 10.2 to the current report on Form 8-K filed on April 16, 2012).
10.1.3	Third Amendment to Second Amended and Restated Credit Agreement, dated as of April 13, 2012, between Resolute Energy Corporation as Borrower and certain of its Subsidiaries as Guarantors, Wells Fargo Bank, National Association, as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.3 to the current report on Form 8-K filed on April 16, 2012).
10.1.4	Fourth Amendment, dated as of December 7, 2012, to the Second Amended and Restated Credit Agreement, by and among Resolute Energy Corporation, as Borrower, and certain of its Subsidiaries as Guarantors, Wells Fargo Bank, National Association, as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.3 to the current report on Form 8-K filed on December 11, 2012).
10.1.5	Fifth Amendment to Second Amended and Restated Credit Agreement dated December 27, 2012, among Resolute Energy Corporation, as Borrower, and certain of its Subsidiaries as Guarantors, Wells Fargo Bank, National Association, as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to the current report on Form 8-K filed on December 31, 2012).
10.1.6	Sixth Amendment to Second Amended and Restated Credit Agreement dated as of March 22, 2013, between Resolute Energy Corporation, as Borrower, Wells Fargo Bank, National Association, as Administrative Agent, and the Lenders party thereto (incorporated by reference as Exhibit 10.1 to the current report on Form 8-K filed on March 25, 2013).
10.1.7	Seventh Amendment to Second Amended and Restated Credit Agreement dated as of April 15, 2013, between Resolute Energy Corporation, as Borrower, Wells Fargo Bank, National Association, as Administrative Agent, and the Lenders party thereto (incorporated by reference as Exhibit 10.1 to the current report on Form 8-K filed on April 15, 2013).
10.1.8	Eighth Amendment to Second Amended and Restated Credit Agreement dated as of December 13, 2013, between Resolute Energy Corporation, as Borrower, Wells Fargo Bank, National Association, as Administrative Agent, and the Lenders party thereto (incorporated by reference as Exhibit 10.1 to the

current report on Form 8-K filed on December 19, 2013).

10.1.9 Ninth Amendment to Second Amended and Restated Credit Agreement dated as of March 7, 2014, between Resolute Energy Corporation, as Borrower, Wells Fargo Bank, National Association, as Administrative Agent, and the Lenders party thereto (incorporated by reference as Exhibit 10.1 to the Annual Report on Form 10-K filed on March 10, 2014).

10.1.10 Tenth Amendment to Second Amended and Restated Credit Agreement dated as of March 14, 2014, between Resolute Energy Corporation, as Borrower, Wells Fargo Bank, National Association, as Administrative Agent, and the Lenders party thereto (incorporated by reference as Exhibit 10.1 to the current report on Form 8-K filed on March 19, 2014).

10.1.11 Eleventh Amendment to Second Amended and Restated Credit Agreement dated as of December 30, 2014, between Resolute Energy Corporation, as Borrower, Wells Fargo National Bank, National Association, as Administrative Agent, and the Lenders party thereto (incorporated by reference as Exhibit 10.2 to the current report on Form 8-K filed on December 31, 2014).

10.1.12 Twelfth Amendment to Second Amended and Restated Credit Agreement, dated as of April 15, 2015, by and among Resolute Energy Corporation, as Borrower, certain subsidiaries of Resolute Energy Corporation, as Guarantors, Wells Fargo Bank, National Association, as Administrative Agent, and the Lenders party thereto (incorporated by reference as Exhibit 10.1 to the current report on Form 8-K filed on April 17, 2015).

Exhibit Number	Description of Exhibits
10.1.13	Thirteenth Amendment to Second Amended and Restated Credit Agreement, dated as of September 30, 2016, among Resolute Energy Corporation as Borrower and certain of its subsidiaries as Guarantors, Wells Fargo Bank, National Association, as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.3 to the Form 8-K filed on October 7, 2016).
10.2	Third Amended and Restated Credit Agreement, dated as of February 17, 2017, by and among Resolute Energy Corporation, as Borrower, certain subsidiaries of Resolute Energy Corporation, as Guarantors, Bank of Montreal, as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to the Form 8-K filed on February 21, 2017).
10.2.1	First Amendment to the Third Amended and Restated Credit Agreement, dated as of May 8, 2017, among Resolute Energy Corporation, as Borrower, certain subsidiaries, as Guarantors, Bank of Montreal, as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to the current report on Form 8-K filed on May 9, 2017).
10.2.2	Second Amendment to the Third Amended and Restated Credit Agreement, dated as of October 18, 2017, among Resolute Energy Corporation, as Borrower, certain subsidiaries, as Guarantors, Bank of Montreal, as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to the current report on Form 8-K filed on October 19, 2017).
10.3#	2009 Performance Incentive Plan (incorporated by reference as Exhibit 10.7 to Amendment No.1 to the Initial S-4 filed on August 31, 2009).
10.3.1#	Amendment No. 1 to 2009 Performance Incentive Plan (incorporated by reference to Exhibit A to the Proxy Statement on Schedule 14A as filed with the SEC on April 25, 2011).
10.3.2#	Amendment No. 2 to 2009 Performance Incentive Plan (incorporated by reference to Exhibit A to the Proxy Statement on Schedule 14A as filed with the SEC on May 11, 2015).
10.3.3#	Amendment No. 3 to 2009 Performance Incentive Plan (incorporated by reference to Exhibit A to the Proxy Statement on Schedule 14A as filed with the SEC on April 11, 2016).
10.3.4#	Amendment No. 4 to 2009 Performance Incentive Plan (incorporated by reference to Exhibit A to the Proxy Statement on Schedule 14A as filed with the SEC on April 11, 2017).
10.4#	Form of Indemnification Agreement between Resolute Energy Corporation and each executive officer and independent director of the Company (incorporated by reference as Exhibit 10.8 to Amendment No. 1 to the initial S-4 filed on August 31, 2009).
10.5††	Cooperative Agreement between Resolute Natural Resources Company and Navajo Nation Oil and Gas Company dated October 22, 2004 (incorporated by reference by Exhibit 10.9 to the Initial S-4).

10.5.1	First Amendment of Cooperative Agreement between Resolute Aneth, LLC and Navajo Nation Oil and Gas Company, Inc. dated October 21, 2005 (incorporated by reference as Exhibit 10.10 to the Initial S-4).
10.5.2	Second Amendment of Cooperative Agreement between Resolute Aneth, LLC and Navajo Nation Oil and Gas Company, Inc. dated April 9, 2012 (incorporated by reference as Exhibit 10.1 to the current report on Form 8-K filed on April 12, 2012).
10.6††	Carbon Dioxide Sale and Purchase Agreement by and between ExxonMobil Gas & Power Marketing Company (a division of Exxon Mobil Corporation), as agent for Mobil Producing Texas & New Mexico, Inc. (Seller) and Resolute Aneth, LLC (Buyer) dated July 1, 2006, as amended July 21, 2006 (incorporated by reference as Exhibit 10.11 to Amendment No. 1 to the Initial S-4 filed on August 31, 2009).
10.7††	Product Sale and Purchase Contract by and between Resolute Natural Resources Company (Buyer) and Kinder Morgan CO_2 Company, L.P. (Seller) dated July 1, 2007, as amended October 1, 2007, January 1, 2009 and October 5, 2010 (incorporated by reference as Exhibit 10.12 to Amendment No. 1 to the Initial S-4 filed on August 31, 2009 and Exhibit 99.1 to the Current Report on Form 8-K filed on October 7, 2010).
10.7.1	Amendment No. 4 to Product Sale and Purchase contract dated July 1, 2007 by and between Resolute Natural Resources Company, LLC and Kinder Morgan CO_2 Company, LP (incorporated by reference to Exhibit 10.1 to the 10-Q filed on November 7, 2011).
10.7.2	Amendment No. 8 to Product Sale and Purchase Contract, dated November 29, 2016 effective October 1, 2016, by and between Resolute Natural Resources Company, LLC and Kinder Morgan CO_2 Company, L.P. (incorporated by reference to Exhibit 10.1 to the Form 8-K filed on December 1, 2016).

Exhibit Number	Description of Exhibits
10.8	Consent Decree, entered into June 2005, relating to alleged violations of the federal Clean Air Act (incorporated by reference as Exhibit 10.16 to the Initial S-4).
10.9	Consent Decree, entered into August 2004, relating to alleged violations of the federal Clean Water Act (incorporated by reference as Exhibit 10.17 to the Initial S-4).
10.10	Crude Oil Purchase Agreement dated July 7, 2014 between Western Refining Southwest, Inc., as purchaser, and Resolute Natural Resources Company, LLC as seller that supersedes the Crude Oil Purchase Agreement dated August 31, 2011 between Western Refining Southwest, Inc., as purchaser, and Resolute Natural Resources Company, LLC, as seller (incorporated by reference to the Exhibit 10.1 on Form 8-K filed on July 11, 2014).
10.10.1	Crude Oil Purchase Agreement dated as of June 1, 2014, regarding Additional Volumes, and as of July 1, 2014, regarding Base Volumes for the sale and purchase of crude oil between Western Refining Southwest, Inc., as purchaser, and Resolute Natural Resources Company, LLC as seller that supersedes the Crude Oil Purchase Agreement dated August 31, 2011 between Western Refining Southwest, Inc., as purchaser, and Resolute Natural Resources Company, LLC, as seller (incorporated by reference to the Exhibit 10.1 on Form 8-K filed on July 11, 2014.
10.10.2	First Amendment to Crude Oil Purchase Agreement dated as of December 31, 2014, between Resolute Energy Corporation as seller, and Western Refining Southwest, Inc. as purchaser (incorporated by reference to the Exhibit 10.3 on Form 8-K filed on December 31, 2014).
10.10.3	Second Amendment to Crude Oil Purchase Agreement dated as of December 31, 2014, between Resolute Energy Corporation as seller, and Western Refining Southwest, Inc. as purchaser (incorporated by reference to the Exhibit 10.1 on Form 8-K filed on December 14, 2015).
10.10.4	Amendment to Crude Oil Purchase Agreement, dated May 9, 2016, by and among Resolute Natural Resources Company, LLC, Western Refining Southwest, Inc. and Navajo Nation Oil and Gas Company (incorporated by reference as Exhibit 10.1 to the report on Form 10-Q filed on May 9, 2016).
10.11#	Form of Retention Award Agreement between Resolute Energy Corporation and certain award recipients (incorporated by reference as Exhibit 10.19 to Amendment No.2 to the Initial S-4 filed on September 8, 2009).
10.12#	Form of Restricted Stock Award Agreement for Non-employee Directors (incorporated by reference to Exhibit 10.13 to the Annual Report on Form 10-K of Resolute Energy Corporation filed on March 30, 2010).

10.13#	Form of Confidentiality and Non Compete Agreement among Resolute Holdings, LLC and certain employees dated as of January 23, 2004 (incorporated by reference to Exhibit 10.14# to the Annual Report on Form 10-K of Resolute Energy Corporation filed on March 30, 2010).
10.14#	Form of Restricted Stock Agreement for Employees (incorporated by referenced as Exhibit 10.1 to the Form 10-Q filed on May 11, 2010).
10.15#	Form of Stock Appreciation Right Agreement for Non-employee Directors (incorporated by reference as Exhibit 10.2 to the 10-Q filed on May 11, 2010).
10.16#	Employment Agreement, effective as of January 1, 2017, by and between the Company and James M. Piccone (incorporated by reference as Exhibit 10.1 to the current report on Form 8-K filed on February 13, 2017).
10.17#	Employment Agreement, effective as of January 1, 2017, by and between the Company and Theodore Gazulis (incorporated by reference as Exhibit 10.2 to the current report on Form 8-K filed on February 13, 2017).
10.18#	Employment Agreement, effective as of January 1, 2017, by and between the Company and Michael N. Stefanoudakis (incorporated by reference as Exhibit 10.3 to the current report on Form 8-K filed on February 13, 2017).
10.19#	Executive Chairman Agreement, effective as of January 1, 2017, by and between the Company and Nicholas J. Sutton (incorporated by reference as Exhibit 10.1 to the current report on Form 8-K filed on January 4, 2017).
10.20#	Employment Agreement, effective as of January 1, 2017, by and between the Company and Richard F. Betz (incorporated by reference as Exhibit 10.2 to the current report on Form 8-K filed on January 4, 2017).
10.21#	Separation Agreement and Release, effective January 1, 2018, by and between the Company and James M. Piccone (incorporated by reference as Exhibit 10.1 to the current report on Form 8-K filed on January 4, 2018).

Exhibit Number	Description of Exhibits
10.22	Purchase Agreement, dated April 20, 2012, among Resolute Energy Corporation, the Guarantors and the Purchasers relating to the 8.50% Senior Notes due 2020 (incorporated by reference to Exhibit 10.1 to the current report on Form 8-K filed on April 26, 2012).
10.23	Purchase Agreement, dated December 5, 2012, among Resolute Energy Corporation, the Guarantors and the Purchasers relating to the 8.50% Senior Notes due 2020 (incorporated by reference to Exhibit 10.1 to the current report on Form 8-K filed on December 11, 2012).
10.24	Secured Term Loan Agreement dated December 30, 2014, between Resolute Energy Corporation as Borrower and certain of its Subsidiaries as Guarantors, Bank of Montreal, as Administrative Agent and the Lenders Party thereto, BMO Capital Markets Corp as Sole Lead Book Runner and Sole Lead Arranger, and Barclays and KeyBanc Capital Markets Inc. as Co-Syndication Agents (as incorporated by reference to Exhibit 10.1 to the current report on Form 8-K filed on December 31, 2014).
10.24.1	Amendment to Secured Term Loan Agreement and Increased Facility Activation Notice-Incremental Term Loans, dated as of May 18, 2015, by and among Resolute Energy Corporation, as Borrower, certain subsidiaries of Resolute Energy Corporation, as guarantors, Bank of Montreal, as administrative agent, and the lenders party thereto (as incorporated by reference to Exhibit 10.1 to the current report on Form 8-K filed on May 19, 2015).
10.25#	Form of Performance Cash Incentive Award Agreement for certain participants (incorporated by referenced as Exhibit 10.2 to the Form 8-K filed on May 11, 2015).
10.26#	Form of Equity Incentive Grant Agreement between Resolute Energy Corporation and certain participants (incorporated by reference as Exhibit 4.1 to the current report on Form 8-K filed on March 14, 2013).
10.27#	Form of Restricted Stock Agreement between Resolute Energy Corporation and certain participants (incorporated by reference as Exhibit 4.2 to the current report on Form 8-K filed on March 14, 2013).
10.28	Purchase and Sale Agreement entered into March 27, 2015 by and between QStar LLC as buyer and Resolute Natural Resources Southwest, LLC as seller effective March 1, 2015 (incorporated by reference to Exhibit 10.1 to the Form 10-Q filed on May 11, 2015).
10.29	Purchase and Sale Agreement entered into September 15, 2015 by and between MCL 1 Oil and Gas Wyoming LLC as buyer and Resolute Wyoming, Inc. as seller (incorporated by reference to Exhibit 10.1 to the Form 10-Q filed on November 9, 2015).

10.30#	Form of Stock Option Agreement between Resolute Energy Corporation and certain participants (incorporated by reference as Exhibit 10.1 to the current report on Form 8-K filed on February 22, 2016).
10.31#	Form of Cash Settled Stock Appreciation Right Grant Agreement between Resolute Energy Corporation and certain participants (incorporated by reference as Exhibit 10.2 to the current report on Form 8-K filed on February 22, 2016).
10.32#	Form of Restricted Cash Incentive Award Agreement between Resolute Energy Corporation and certain participants (incorporated by reference as Exhibit 10.3 to the current report on Form 8-K filed on February 22, 2016).
10.33	Form of Cash Settled Stock Appreciation Right Grant Agreement (Non-Employee Directors) between Resolute Energy Corporation and certain participants (incorporated by reference as Exhibit 10.33 to the annual report on Form 10-K filed on March 7, 2016).
10.34	Form of Restricted Stock Agreement (Non-Employee Directors) between Resolute Energy Corporation and certain participants (incorporated by reference as Exhibit 10.34 to the annual report on Form 10-K filed on March 7, 2016).
10.35†	Purchase and Sale Agreement dated July 7, 2016, by and between Resolute Natural Resources Southwest, LLC and Firewheel Energy, LLC, as sellers and Caprock Permian Processing LLC and Caprock Field Services LLC, as buyers (incorporated by reference to Exhibit 10.1 to the current report on Form 8-K filed on August 2, 2016).
10.36†	Purchase and Sale Agreement dated July 7, 2016, by and between Resolute Natural Resources Southwest, LLC, as seller, and Caprock Permian Processing LLC and Caprock Field Services LLC, as buyers (incorporated by reference to Exhibit 10.2 to the current report on Form 8-K filed on August 2, 2016).
10.37	Earn-Out Agreement dated July 7, 2016 by and between Resolute Natural Resources Southwest, LLC and Firewheel Energy, LLC, as sellers and Caprock Permian Processing LLC and Caprock Field Services LLC, as buyers (incorporated by reference to Exhibit 10.3 to the current report on Form 8-K filed on August 2, 2016).

Exhibit Number	Description of Exhibits
10.37.1	First Amended and Restated Earn-Out Agreement dated March 10, 2017 by and between Resolute Natural Resources Southwest, LLC, as seller and Caprock Permian Processing LLC and Caprock Field Services LLC, as buyers (incorporated by reference to Exhibit 10.37.1 to the annual report on Form 10-K filed on March 13, 2017).
10.38	Convertible Preferred Stock Purchase Agreement, dated October 4, 2016, between Resolute Energy Corporation and BMO Capital Markets Corp. (incorporated by reference to Exhibit 10.1 to the current report on Form 8-K filed on October 7, 2016).
10.39	Convertible Preferred Stock Registration Rights Agreement, dated October 4, 2016, between Resolute Energy Corporation and Firewheel Energy, LLC. (incorporated by reference to Exhibit 10.2 to the current report on Form 8-K filed on October 7, 2016).
10.40	Underwriting Agreement, dated December 19, 2016, between Resolute Energy Corporation, BMO Capital Markets Corp. and Goldman Sachs & Co., as a representatives of the several underwriters named therein (incorporated by reference to Exhibit 1.1 to the current report on Form 8-K filed on December 22, 2016).
10.41	Commitment Letter between Resolute Energy Corporation and BMO Capital Markets dated March 3, 2017 in reference to financing the CP Acquisition announced on March 3, 2017 (incorporated by reference to Exhibit 10.1 on Form 8-K filed on March 3, 2017).
10.42†	Crude Oil Connection and Dedication Agreement dated April 27, 2017, by and between Resolute Natural Resources Southwest, LLC, a Delaware limited liability company, as Producer, and Caprock Permian Crude LLC, as Carrier (incorporated by reference to Exhibit 10.1 to the current report on Form 10-Q filed on August 7, 2017).
10.43†	Crude Oil Purchase Contract dated April 27, 2017, by and between Resolute Natural Resources Southwest LLC and Plains Marketing, L.P. (incorporated by reference to Exhibit 10.2 to the current report on Form 10-Q filed on August 7, 2017).
10.44#	Form of Equity Incentive Grant Agreement between Resolute Energy Corporation and certain participants (incorporated by reference as Exhibit 4.1 to the current report on Form 8-K filed on February 13, 2017).
10.45#	Form of Equity Incentive Grant Agreement between Resolute Energy Corporation and certain participants (incorporated by reference as Exhibit 4.1 to the current report on Form 8-K filed on February 16, 2018).
12.1	Statement of Ratio of Earnings to Fixed Charges.
23.1	Consent of KPMG LLP.
23.2	Consent of Netherland, Sewell & Associates, Inc.
31.1	Certification of the Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of the Chief Financial Officer pursuant to Section 302 of the Sarbanes Oxley Act of 2002.
32	Certification of the Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1	Report of Netherland, Sewell & Associates, Inc. regarding the registrant’s reserves as of December 31, 2017.

101	The following materials are filed herewith: (i) XBRL Instance Document, (ii) XBRL Taxonomy Extension Schema Document, (iii) XBRL Taxonomy Extension Calculation Linkbase Document, (iv) XBRL Taxonomy Extension Labels Linkbase Document, (v) XBRL Taxonomy Extension Presentation Linkbase Document, and (vi) XBRL Taxonomy Extension Definition Linkbase Document.

†Certain of the schedules, exhibits and similar attachments attached to these exhibits have been omitted pursuant to Item 601 (b)(2) of Regulation S-K. Resolute agrees to furnish supplementally a copy of any omitted schedule, exhibit or similar attachment to the Securities and Exchange Commission upon request.
††Portions of this exhibit have been omitted pursuant to a request for confidential treatment.
#Management Contract, Compensation Plan or Agreement.

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.

RESOLUTE ENERGY CORPORATION Dated: March 12, 2018

/s/ Richard F. Betz

By:
Richard F. Betz, Chief Executive Officer and Director

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/ Richard F. Betz Richard F. Betz	Chief Executive Officer and Director (Principal Executive Officer)	March 12, 2018
/s/ Theodore Gazulis Theodore Gazulis	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 12, 2018
/s/ J. A. Tuell J. A. Tuell	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)	March 12, 2018
/s/ Nicholas J. Sutton Nicholas J. Sutton	Executive Chairman and Director	March 12, 2018
/s/ James E. Duffy James E. Duffy	Director	March 12, 2018
/s/ Thomas O. Hicks, Jr. Thomas O. Hicks, Jr.	Director	March 12, 2018
/s/ Gary L. Hultquist	Director	March 12, 2018

Gary L. Hultquist		
/s/ William K. White William K. White	Director	March 12, 2018
/s/ Tod C. Benton Tod C. Benton	Director	March 12, 2018
/s/ Janet W. Pasque Janet W. Pasque	Director	March 12, 2018

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RESOLUTE ENERGY CORPORATION

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Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors
Resolute Energy Corporation:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Resolute Energy Corporation and subsidiaries (the Company) as of December 31, 2017 and 2016, the related consolidated statements of operations, stockholders' equity (deficit), and cash flows for each of the years in the three year period ended December 31, 2017, and the related notes (collectively, the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2017, 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, 2017, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 12, 2018 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated 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 consolidated 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 consolidated 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 consolidated 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 consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ KPMG LLP

We have served as the Company's auditor since 2007.

Denver, Colorado
March 12, 2018

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors
Resolute Energy Corporation:

Opinion on Internal Control Over Financial Reporting

We have audited Resolute Energy Corporation and subsidiaries (the Company) internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

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, 2017 and 2016, the related consolidated statements of income, comprehensive income, stockholders' equity (deficit), and cash flows for each of the years in the three-year period ended December 31, 2017, and the related notes (collectively, the "consolidated financial statements"), and our report dated March 12, 2018 expressed an unqualified opinion on those consolidated financial statements.

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 Annual 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 of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included 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/ KPMG LLP

Denver, Colorado
March 12, 2018

RESOLUTE ENERGY CORPORATION

Consolidated Balance Sheets

(in thousands, except share amounts)

	December 31, 2017	2016
Assets		
Current assets:		
Cash and cash equivalents	$3,762	$133,089
Accounts receivable	63,420	55,228
Commodity derivative instruments	526	218
Contingent payment derivative instrument	8,311	—
Prepaid expenses and other current assets	1,856	3,249
Total current assets	77,875	191,784
Property and equipment, at cost:		
Oil and gas properties, full cost method of accounting		
Unproved	248,059	121,375
Proved	2,030,316	1,889,111
Other property and equipment	12,879	9,754
Accumulated depletion, depreciation and amortization	(1,737,116)	(1,647,120)
Net property and equipment	554,138	373,120
Other assets:		
Contingent payment derivative instrument	9,635	—
Other assets	274	332
Restricted cash	—	23,137
Total assets	$641,922	$588,373
Liabilities and Stockholders' Deficit		
Current liabilities:		
Accounts payable	$16,077	$8,675
Accrued expenses	53,214	37,507
Accrued revenue payable	28,255	19,801
Accrued cash-settled incentive awards	34,317	27,158
Accrued interest payable	7,574	5,784
Asset retirement obligations	540	895
Commodity derivative instruments	20,822	8,014
Secured term loan facility	—	122,139
Total current liabilities	160,799	229,973
Long term liabilities:		
Revolving credit facility	27,487	8,821
Senior notes	523,240	397,154
Asset retirement obligations	2,247	19,457
Commodity derivative instruments	990	4,104
Other long term liabilities	1,568	4,611
Total liabilities	716,331	664,120
Commitments and contingencies		

Stockholders’ deficit:		
Convertible preferred stock, $0.0001 par value; 1,000,000 shares authorized; issued and outstanding 62,500 and 62,500 shares at December 31, 2017 and 2016, respectively; $62.5 million liquidation preference	—	—
Common stock, $0.0001 par value; 45,000,000 shares authorized; issued and outstanding 22,527,652 and 21,932,842 shares at December 31, 2017 and 2016, respectively	2	2
Additional paid-in capital	957,426	948,380
Accumulated deficit	(1,031,837)	(1,024,129)
Total stockholders’ deficit	(74,409)	(75,747)
Total liabilities and stockholders’ deficit	$641,922	$588,373

See notes to consolidated financial statements

RESOLUTE ENERGY CORPORATION

Consolidated Statements of Operations

(in thousands, except per share data)

	Years Ended December 31,		
	2017	2016	2015
Revenue:			
Oil	$254,606	$148,336	$137,893
Gas	25,572	10,661	12,628
Natural gas liquids	23,300	5,481	4,123
Total revenue	303,478	164,478	154,644
Operating expenses:			
Lease operating	79,308	63,699	79,393
Production and ad valorem taxes	23,351	16,270	19,985
Depletion, depreciation, amortization, and asset retirement obligation accretion	92,089	50,462	94,338
Impairment of proved oil and gas properties	—	58,000	705,000
General and administrative	48,537	32,627	31,447
Cash-settled incentive awards	16,174	34,926	1,185
Total operating expenses	259,459	255,984	931,348
Income (loss) from operations	44,019	(91,506)	(776,704)
Other income (expense):			
Interest expense, net	(43,449)	(50,684)	(64,358)
Commodity derivative instruments gain (loss)	(5,655)	(19,784)	76,492
Contingent payment derivative instrument gain	3,464	—	—
Other income (expense)	95	343	(63)
Total other income (expense)	(45,545)	(70,125)	12,071
Loss before income taxes	(1,526)	(161,631)	(764,633)
Income tax benefit (expense)	293	(91)	22,354
Net loss	(1,233)	(161,722)	(742,279)
Preferred stock dividends	(6,475)	—	—
Net loss available to common shareholders	$(7,708)	$(161,722)	$(742,279)
Net loss per common share:			
Basic and diluted	$(0.35)	$(10.33)	$(49.55)
Weighted average common shares outstanding:			
Basic and diluted	21,889	15,767	14,986

See notes to consolidated financial statements

RESOLUTE ENERGY CORPORATION

Consolidated Statements of Stockholders' Equity (Deficit)

(in thousands)

	Common Stock Shares	Common Stock Amount	Preferred Stock Shares	Preferred Stock Amount	Additional Paid-in Capital	Accumulated Deficit	Total Stockholders' Equity (Deficit)
Balance as of January 1, 2015	15,527	$ 2	—	$ —	$ 646,744	$ (120,128)	$ 526,618
Issuance of stock, restricted stock and share-based compensation	32	—	—	—	12,556	—	12,556
Redemption of restricted stock for employee income tax, restricted stock forfeitures and expirations	(117)	—	—	—	(176)	—	(176)
Net loss	—	—	—	—		(742,279)	(742,279)
Balance as of December 31, 2015	15,442	$ 2	—	$ —	$ 659,124	$ (862,407)	$ (203,281)
Issuance of stock, restricted stock and share-based compensation	93	—	—	—	6,423	—	6,423
Redemption of restricted stock for employee income tax, restricted stock forfeitures and expirations	(109)	—	—	—	(122)	—	(122)
Exercise of employee options to purchase common stock	22	—	—	—	98	—	98
Issuance of preferred stock, net of underwriters discounts	—	—	63	—	59,677	—	59,677
Issuance of common stock to Firewheel	2,115	—	—	—	62,293	—	62,293
Issuance of common stock, net of underwriters discounts	4,370	—	—	—	160,887	—	160,887
Net loss	—	—	—	—	—	(161,722)	(161,722)
Balance as of December 31, 2016	21,933	$ 2	63	$ —	$ 948,380	$ (1,024,129)	$ (75,747)

Issuance of stock, restricted stock and share-based compensation	592	—	—	—	12,188	—	12,188
Redemption of restricted stock for employee income tax, restricted stock forfeitures and expirations	(105)	—	—	—	(3,394)	—	(3,394)
Exercise of employee options to purchase common stock	108	—	—	—	252	—	252
Preferred stock dividend	—	—	—	—	—	(6,475)	(6,475)
Net loss	—	—	—	—	—	(1,233)	(1,233)
Balance as of December 31, 2017	22,528	$ 2	63	—	$ 957,426	$ (1,031,837)	$ (74,409)

See notes to consolidated financial statements

RESOLUTE ENERGY CORPORATION

Consolidated Statements of Cash Flows

(in thousands)

	Years Ended December 31,		
	2017	2016	2015
Operating activities:			
Net loss	$(1,233)	$(161,722)	$(742,279)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depletion, depreciation, amortization and asset retirement obligation accretion	92,089	50,462	94,338
Impairment of proved oil and gas properties	—	58,000	705,000
Amortization of deferred financing costs and long-term debt premium and discount	9,336	5,240	11,578
Share-based compensation	12,161	6,315	12,148
Commodity derivative instruments loss (gain)	5,655	19,784	(76,492)
Commodity derivative settlement gains	3,730	88,010	93,150
Unrealized contingent payment derivative instrument gain	(3,464)	—	—
Deferred income tax benefit	—	—	(22,354)
Change in operating assets and liabilities:			
Accounts receivable	(7,592)	(18,019)	21,216
Other current assets	(577)	109	322
Accounts payable and accrued expenses	25,337	35,520	(27,173)
Accrued interest payable	1,790	20	25
Net cash provided by operating activities	137,232	83,719	69,479
Investing activities:			
Oil and gas exploration and development expenditures	(306,073)	(128,340)	(67,636)
Purchase of oil and gas properties	(161,264)	(95,940)	—
Proceeds from sale of oil and gas properties and other	198,175	35,477	268,773
Purchase of other property and equipment	(3,402)	(106)	(124)
Restricted cash	1,044	(1,640)	(1,489)
Other long-term assets	31	82	59
Net cash provided by (used in) investing activities	(271,489)	(190,467)	199,583
Financing activities:			
Proceeds from bank borrowings	381,000	156,500	183,000
Repayments of bank borrowings	(361,000)	(146,500)	(418,000)
Proceeds from issuance of senior notes	126,875	—	—
Repayment of term loans	(128,303)	—	(71,697)
Payment of preferred dividend	(5,205)	—	—
Payment of financing costs	(5,295)	—	(3,744)
Redemption of restricted stock for employee income taxes	(3,394)	(122)	(176)
Proceeds from exercise of employee options to purchase common stock	252	98	—
Proceeds from issuance of common stock, net of underwriters discounts and commissions	—	160,887	—
Proceeds from issuance of preferred stock, net of underwriters discounts and commissions	—	59,677	—

Proceeds from issuance of term loans	—	—	46,500
Net cash provided by (used in) financing activities	4,930	230,540	(264,117)
Net increase in cash and cash equivalents	(129,327)	123,792	4,945
Cash and cash equivalents at beginning of period	133,089	9,297	4,352
Cash and cash equivalents at end of period	$3,762	$133,089	$9,297
Supplemental disclosures of cash flow information:			
Cash paid during the period for:			
Interest, net of amounts capitalized	$32,323	$50,684	$64,364
Income taxes	$63	$—	$—
Supplemental schedule of non-cash investing and financing activities:			
Issuance of common stock for purchase of oil and gas properties	$—	$62,293	$—
Capital expenditures financed through current liabilities	$25,883	$18,440	$10,482
Increase (decrease) to asset retirement obligations	$1,424	$412	$333
Asset retirement obligations assumed	$23	$587	$—
Asset retirement obligations sold	$19,680	$1,081	$14,985

See notes to consolidated financial statements

RESOLUTE ENERGY CORPORATION

Notes To Consolidated Financial Statements

Note 1 — Organization and Nature of Business

Resolute Energy Corporation ("Resolute" or the "Company"), is an independent oil and gas company engaged in the exploitation, development, exploration for and acquisition of oil and gas properties. The Company's operating assets are comprised of properties in the Delaware Basin in west Texas (the "Delaware Basin Properties"). As discussed in Note 3, the Company closed on the disposition of Aneth Field, located in the Paradox Basin in southeast Utah (the "Aneth Field Properties" or "Aneth Field"), on November 6, 2017. All periods presented include the results related to Aneth Field, prior to the disposition. The Company conducts all of its activities in the United States of America.

Resolute Energy Corporation, the stand-alone parent entity, has insignificant independent assets and no operations. Its guarantees are full and unconditional and joint and several, and there are no subsidiaries of the parent company other than the Guarantors (defined below). There are no restrictions on the Company's ability to obtain cash dividends or other distributions of funds from its subsidiaries, except those imposed by applicable law.

Note 2 — Basis of Presentation and Summary of Significant Accounting Policies

Basis of Presentation

The consolidated financial statements include Resolute and its subsidiaries, and have been prepared in accordance with accounting principles generally accepted in the United States ("GAAP"). All significant intercompany transactions have been eliminated upon consolidation. Certain prior period amounts have been reclassified to conform to the current period presentation.

In connection with the preparation of the consolidated financial statements, Resolute evaluated subsequent events that occurred after the balance sheet date, through the date of filing.

Assumptions, Judgments and Estimates

The preparation of the condensed consolidated financial statements in conformity with GAAP requires management to make various assumptions, judgments and estimates to determine the reported amounts of assets, liabilities, revenue and expenses, and in the disclosures of commitments and contingencies. Changes in these assumptions, judgments and estimates will occur as a result of the passage of time and the occurrence of future events. Accordingly, actual results could differ from amounts previously established.

Significant estimates with regard to the condensed consolidated financial statements include proved oil and gas reserve volumes and the related present value of estimated future net cash flows used in the ceiling test applied to capitalized oil and gas properties; the estimated fair value and allocation of the purchase price related to business combinations; share-based compensation expense; cash-settled long-term incentive expense; depletion depreciation, and amortization; accrued liabilities; and revenue and related receivables.

Fair Value of Financial Instruments

The carrying amount of the majority of Resolute's financial instruments, namely cash and cash equivalents, accounts receivable and accounts payable, approximate their fair value because of the short-term nature of these instruments. The Revolving Credit Facility (defined in Note 5) has a recorded value that approximates its fair market value. The fair value of $535.1 million under the senior notes due May 1, 2020 (the "Senior Notes" or the "Notes") is based on data from independent market makers or price received at measurement date. The fair value of derivative instruments (see Note 10) is estimated based on market conditions in effect at the end of each reporting period.

Industry Segment and Geographic Information

Resolute conducts oil, gas and natural gas liquids ("NGL") exploration and production operations in one segment. All of Resolute's operations and assets are located in the United States, and all of its revenue is attributable to domestic customers. Resolute considers gathering, processing and marketing functions as supportive of its oil and gas producing activities, and accordingly, they are not reported as separate segments.

Cash and Cash Equivalents

Resolute considers all highly liquid investments with original maturities of three months or less at the date of purchase to be cash equivalents. Resolute periodically maintains cash and cash equivalents in bank deposit accounts and money market funds which may be in excess of federally insured amounts. Resolute has not experienced any losses in such accounts and believes it is not exposed to any significant credit risk on such accounts.

Accounts Receivable

The Company's accounts receivable consist of the following for the periods indicated (in thousands):

	December 31, 2017	December 31, 2016
Trade receivables	$18,079	$14,898
Revenue receivables	43,136	32,817
Derivative receivables	1,560	5,695
Other receivables	645	1,818
Total accounts receivable	$63,420	$55,228

The Company's accounts receivable consist mainly of receivables from oil, gas, and NGL purchasers and from joint interest owners on properties the Company operates. For receivables from joint interest owners, the Company typically has the ability to withhold future revenue disbursements to recover non-payment of joint interest billings. Generally, the Company's oil and gas trade receivables are due between fifteen and thirty days and are collected in less than two months, and the Company has had minimal bad debts.

The Company routinely assesses the recoverability of all material trade and other receivables to determine their collectability. As of December 31, 2017 and 2016, the Company had no allowance for doubtful accounts recorded.

Concentration of Credit Risk

Financial instruments that potentially subject Resolute to concentrations of credit risk consist primarily of trade, production and derivative settlement receivables. Resolute derived approximately 50%, 24% and 15% of its total 2017 revenue from Plains Marketing L.P., Western Refining, Inc. ("Western") and ETC Field Services, respectively; 47%, 27% and 13% of its total 2016 revenue from Western, Plains Marketing L.P. and Holly Frontier LLC, respectively and 58% and 14% of its total 2015 revenue from Western and Holly Frontier LLC, respectively. If Resolute was compelled to sell its oil and gas to an alternative market, costs associated with the transportation of its production may increase, and such increase could materially and negatively affect its operations. The concentration of credit risk in the oil and gas industry affects the overall exposure to credit risk because customers may be similarly affected by changes in economic or other conditions. The creditworthiness of customers and other counterparties is subject to continuing review, including the use of master netting agreements where appropriate. Commodity derivative contracts expose Resolute to the credit risk of non-performance by the counterparty to the contracts. This exposure is diversified among major investment grade financial institutions. All counterparties are current lenders under Resolute's Revolving Credit Facility (defined in Note 5).

Oil and Gas Properties

The Company uses the full cost method of accounting for oil and gas producing activities. All costs incurred in the acquisition, exploration and development of properties, including costs of unsuccessful exploration, costs of surrendered and abandoned leaseholds, delay lease rentals and the fair value of estimated future costs of site restoration, dismantlement and abandonment activities, improved recovery systems and a portion of general and administrative and operating expenses are capitalized on a country wide basis (the "Cost Center").

In Aneth Field (disposed of in November 2017), Resolute conducted tertiary recovery projects on certain of its oil and gas properties in order to recover additional hydrocarbons that are not recoverable from primary or secondary recovery methods. Under the full cost method, all development costs were capitalized at the time incurred. Development costs included charges associated with access to and preparation of well locations, drilling and equipping development wells, test wells, and service wells including injection wells, and acquiring, constructing, and installing production facilities and provided for improved recovery systems. Improved recovery systems included all related facility development costs and the cost of the acquisition of tertiary injectants, primarily purchased carbon dioxide (“CO_2”). The development costs related to CO_2 purchases were incurred solely for the purpose of gaining access to incremental reserves not otherwise recoverable. The accumulation of injected CO_2, in combination with additional purchased and recycled CO_2, provided future economic value over the life of the project.

In contrast, other costs related to the daily operation of the improved recovery systems were considered production costs and were expensed as incurred. These costs included, but were not limited to, compression, electricity, separation, re-injection of recovered CO_2 and water and reservoir pressure maintenance.

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Capitalized general and administrative and operating costs include salaries, employee benefits, costs of consulting services and other specifically identifiable capital costs and do not include costs related to production operations, general corporate overhead or similar activities. Resolute capitalized general and administrative and operating costs related to its acquisition, exploration and development activities of $6.6 million during 2017, $5.7 million during 2016 and $6.3 million during 2015.

Investments in unproved properties are not depleted, pending determination of the existence of proved reserves. The Company's investments in unproved properties are related to an exploration play in the Delaware Basin in Texas. Unproved properties are assessed at least annually to determine whether impairment has occurred. Unproved properties whose costs are individually significant are assessed individually by considering the primary lease terms of the properties, the holding period of the properties and geographic and geologic data obtained relating to the properties. Where it is not practicable to assess individually the amount of impairment of properties for which costs are not individually significant, such properties are grouped for purposes of assessing impairment. The amount of impairment assessed, if any, is added to the costs to be amortized.

No gain or loss is recognized upon the sale or abandonment of undeveloped or producing oil and gas properties unless the sale represents a significant portion of the Company's oil and gas properties and the gain or loss significantly alters the relationship between the capitalized costs and proved reserves of the cost center.

Depletion of oil and gas properties is computed on the unit-of-production method based on proved reserves. Depletable costs include estimates of asset retirement obligations and future development costs of proved reserves, including, but not limited to, costs to drill and equip development wells, construct and install production and processing facilities, and improved recovery systems.

Pursuant to full cost accounting rules, Resolute is required to perform a quarterly "ceiling test" calculation to test its oil and gas properties for possible impairment. The primary components impacting the calculation are commodity prices, reserve quantities added and produced, overall exploration and development costs and depletion expense. If the net capitalized cost of the Company's oil and gas properties subject to amortization (the "carrying value") exceeds the ceiling limitation, the excess would be charged to expense. The ceiling limitation is equal to the sum of the present value discounted at 10% of estimated future net cash flows from proved reserves, the cost of properties not being amortized, the lower of cost or estimated fair value of unproven properties included in the costs being amortized, and all related income tax effects.

During 2017, 2016 and 2015, the Company recorded $0, $58 million and $705 million, respectively, non-cash impairments of the carrying value of its oil and gas properties as a result of the ceiling test limitation. If in future periods a negative factor impacts one or more of the components of the calculation, including market prices of oil and gas (based on a trailing twelve-month unweighted average of the oil and gas prices in effect on the first day of each month), differentials from posted prices, future drilling and capital plans, operating costs or expected production, the Company may incur full cost ceiling impairment related to its oil and gas properties in such periods.

Capitalized Interest

Interest is capitalized when associated with significant investments in unproved properties and major development projects that are excluded from current depletion, depreciation and amortization calculations and on which exploration or development activities are in progress. Capitalized interest is calculated by multiplying the Company's weighted-average interest rate on debt outstanding by the amount of qualified costs. Capitalized interest totaled $15.8 million, $4.1 million and $6.0 million during 2017, 2016 and 2015, respectively.

Business Combinations

The Company accounts for all business combinations using the acquisition method which involves the use of significant judgment. Under the acquisition method, a business combination is accounted for based on the fair value of the consideration given. The assets and liabilities acquired are measured at fair value and the purchase price is allocated to the assets and liabilities based on these fair values. The excess of the cost of an acquisition, if any, over the fair value of the assets acquired and liabilities assumed is recognized as goodwill. The excess of the fair value of assets acquired and liabilities assumed over the cost of an acquisition, if any, is recognized immediately in earnings as a gain. Determining the fair values of the assets and liabilities acquired involves the use of judgment as fair values are not always readily determinable. Different techniques may be used to determine fair values, including market prices (where available), appraisals, comparisons to transactions for similar assets and liabilities and the present value of estimated future cash flows, among others.

Other Property and Equipment

Other property and equipment are recorded at cost. Costs of renewals and improvements that substantially extend the useful lives of the assets are capitalized. Maintenance and repair costs which do not extend the useful lives of property and equipment are charged to expense as incurred. Depreciation and amortization is calculated using the straight-line method over the estimated useful lives of the assets. Office furniture, automobiles, and computer hardware and software are depreciated over three to five years. Field offices and partial ownership of aircraft are depreciated over fifteen to twenty years. Leasehold improvements are depreciated, using the straight line method, over the shorter of the lease term or the useful life of the asset. When other property and equipment is sold or retired, the capitalized costs and related accumulated depreciation and amortization are removed from the accounts.

Asset Retirement Obligations

Asset retirement obligations relate to future costs associated with the plugging and abandonment of oil and gas wells, removal of equipment and facilities from leased acreage and returning such land to its original condition. The fair value of a liability for an asset retirement obligation is recorded in the period in which it is incurred and the cost of such liability is recorded as an increase in the carrying amount of the related long-lived asset by the same amount. The liability is accreted each period and the capitalized cost is depleted as part of the full cost pool. Revisions to estimated asset retirement obligations result in adjustments to the related capitalized asset and corresponding liability.

The restricted cash balance of $23.2 million previously located on the Company’s consolidated balance sheet was contractually restricted for the purpose of settling asset retirement obligations of Aneth Field. Due to the disposition of Aneth Field, this asset and these obligations were transferred to the purchaser and the associated restricted cash balance is $0 as of December 31, 2017.

Derivative Instruments

Resolute utilizes derivative instruments to manage its exposure to oil and gas price volatility and these instruments may take the form of swaps, puts, calls, collars and other such arrangements. Derivative instruments are recognized on the balance sheet as either assets or liabilities measured at fair value. Resolute has not elected to apply cash flow hedge accounting, and consequently, recognizes gains and losses in earnings rather than deferring such amounts in other comprehensive income as allowed under cash flow hedge accounting. Realized gains and losses on derivative instruments are recognized in the period in which the related contract is settled. Both the realized and mark-to-market gains and losses on derivative instruments are reflected in other income (expense) in the consolidated statements of operations. Cash flows from commodity derivatives are reported as cash flows from operating activities.

Revenue Recognition

Oil and gas revenue is recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred and the collectability of the revenue is probable. Oil and gas revenue is recorded using the sales method.

Deferred Financing Costs

Deferred financing costs are amortized over the estimated life of the related obligation and it is our policy to net these costs against the related debt. The Company incurred $5.3 million in deferred financing costs in 2017, $0 in 2016 and $0 in 2015, and amortized $2.7 million, $3.1 million and $5.0 million to interest expense during 2017, 2016 and 2015, respectively.

General and Administrative Expenses

General and administrative expenses are reported net of amounts capitalized to oil and gas properties and of reimbursements of overhead costs that are billed to working interest owners of the oil and gas properties operated by Resolute.

Long-term Employee Incentive Expense

Share-based compensation expense is measured at the estimated grant date fair value of the awards and is amortized over the requisite service period (usually the vesting period). The unique inputs of each of the equity awards are outlined as follows:

- Stock option award expense – measured using a Black-Scholes pricing model, no dividends, and expected price volatility and risk-free rates relative to the expected term.
- Time-based restricted stock award expense – measured based on the Company’s closing stock price on the date of grant.
- TSR award expense – measured based on a Monte Carlo simulation model, no dividends, and expected price volatility and risk-free rates relative to the expected term.

Cash-settled incentive award expense is measured quarterly and is amortized over the requisite service period (usually the vesting period). The unique inputs of each of the liability awards are outlined as follows:

- Cash-settled stock appreciation rights – measured using a Black-Scholes pricing model, no dividends, and expected price volatility and risk-free rates relative to the expected term.
- Time-based restricted cash awards – measured based on the cash value per unit ($1 per unit) on the date of grant.
- Performance-based restricted cash awards – measured using a Black-Scholes cash-or-nothing valuation model, no dividends, and expected price volatility and risk-free rates relative to the expected term.

The Company estimates forfeitures in calculating the cost related to share-based compensation expense and cash-settled incentive awards expense as opposed to recognizing these forfeitures and the corresponding reduction in expense as they occur.

The Company calculates the respective award’s price volatility using an average of the Company’s peer group (as determined by our Total Stockholder Return awards) based on the date of grant or quarterly valuation date for the expected term. Rick-free rates are obtained directly from the U.S. Department of the Treasury.

Income Taxes

Income taxes and uncertain tax positions are accounted for in accordance with FASB Accounting Standards Codification (“ASC”) Topic 740, Accounting for Income Taxes. Deferred income taxes are provided for the differences between the bases of assets and liabilities for financial reporting and income tax purposes. A valuation allowance is established when necessary to reduce deferred tax assets to the amount expected to be realized. Tax positions meeting the more-likely-than-not recognition threshold are measured pursuant to the guidance set forth in FASB ASC Topic 740.

Recent Accounting Pronouncements

In January 2017 the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) 2017-01, Business Combinations (Topic 805): Clarifying the Definition of a Business, which clarifies the definition of a business to assist entities with evaluating when a set of transferred assets and activities is deemed to be a business. Determining whether a transferred set constitutes a business is important because the accounting for a business combination differs from that of an asset acquisition. The definition of a business also affects the accounting for dispositions. Under the new standard, when substantially all of the fair value of assets acquired is concentrated in a single asset, or a group of similar assets, the assets acquired would not represent a business and business combination accounting would not be required. Early adoption is permitted. The Company elected to early adopt this standard in the second quarter of 2017.

In May 2014, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) 2014-09, Revenue from Contracts with Customers (Topic 606), which is effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period. The new revenue standard provides a five-step analysis of transactions to determine when and how revenue is recognized. The core principle of the guidance is that a company should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The guidance in this update supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, and most industry-specific guidance throughout the Industry Topics of the Codification. Entities can choose to adopt the standard using either the full retrospective approach or a modified retrospective approach. We will adopt the standard effective January 1, 2018, utilizing the modified retrospective approach, which will be applied to contracts that were not completed as of January 1, 2018. During 2017, the Company completed its analysis of the impact of the standard on its contract types, and it does not believe that the adoption of ASU 2014-09 and ASU 2016-12 have material impact on its financial results. The Company has also modified current processes and controls to apply the requirements of the new standard. We do not believe such modifications are material to our internal controls over financial reporting. Additionally, we do not believe that adoption of the standard will impact our operational strategies and financial results.

In February 2016, the FASB issued ASU 2016-02, Leases (Topic 842), which requires lessees to present nearly all leasing arrangements on the balance sheet as liabilities along with a corresponding right-of-use asset. The ASU will replace most existing lease guidance in GAAP when it becomes effective. The new standard becomes effective for the Company on January 1, 2019. Although early application is permitted, the Company does not plan to early adopt the ASU. The standard requires the use of the modified retrospective transition method. The Company is evaluating the effect that ASU 2016-02 will have on its consolidated financial statements and related disclosures. Currently, the Company is evaluating the standard's applicability to our various contractual arrangements. We believe that adoption of the standard will result in increases to our assets and liabilities on our consolidated balance sheet. However, we have not yet determined the extent of the adjustments that will be required upon implementation of the standard. We continue to monitor relevant industry guidance regarding the implementation of ASU 2016-02 and will adjust our implementation strategies as necessary. We are in the process of evaluating the potential impact of adopting the new standard.

Note 3 — Acquisitions and Divestitures

Acquisition of Reeves County Properties in the Delaware Basin

Delaware Basin Bronco Acquisition

In May 2017 Resolute Natural Resources Southwest, LLC (“Resolute Southwest”), a wholly owned subsidiary of the Company, closed on a Purchase and Sale Agreement with CP Exploration II, LLC and Petrocap CPX, LLC pursuant to which Resolute Southwest acquired certain undeveloped and developed oil and gas properties in the Delaware Basin in Reeves County, Texas (the “Delaware Basin Bronco Acquisition”).

The acquisition was accounted for as an asset acquisition, and therefore, the properties were recorded based on the fair value of the total consideration transferred on the acquisition date and transaction costs were capitalized as a component of the cost of the assets acquired. The Company acquired these properties for $161.3 million, which it financed substantially with proceeds received from the offering of $125 million of 8.50% Senior Notes due 2020 (as defined in Note 5) that closed in May 2017. The Company recorded $144.8 million of the total consideration transferred as unproved oil and gas property.

The properties acquired include approximately 4,600 net acres in Reeves County, Texas (the “Bronco Assets”), which were considered predominantly unproved, consisting of 2,187 net acres adjacent to the Company’s existing operating area in Reeves County and 2,405 net acres in southern Reeves County.

Delaware Basin Firewheel Acquisition

In October 2016, Resolute and Resolute Southwest closed on a Purchase and Sale Agreement with Firewheel Energy, LLC (“Firewheel”) pursuant to which Resolute Southwest acquired certain oil and gas interests in the Delaware Basin in Reeves County, Texas (the “Firewheel Properties”), for consideration to Firewheel consisting of $90 million in cash and 2,114,523 shares of common stock of the Company, par value $0.0001 per share, issued to Firewheel upon the closing of the purchase of the Firewheel Properties (the “Delaware Basin Firewheel Acquisition”).

The Company acquired the Firewheel Properties for $153.2 million. Revenue and expenses related to the acquired properties are included in the consolidated statement of operations on the closing date of the transaction. The Delaware Basin Firewheel Acquisition was accounted for as a business combination using the acquisition method.

The Company completed its assessment of the fair values of the assets acquired and liabilities assumed. Accordingly, the following table presents the purchase price allocation of the Delaware Basin Firewheel Acquisition at the indicated date below, based on the fair values of assets acquired and liabilities assumed (in thousands):

	2016
Proved oil and gas properties	$40,900
Unproved oil and gas properties	112,800
Asset retirement obligations assumed	(500)
Total purchase price	$153,200

Divestiture of Aneth Field

In November 2017, Resolute Energy Corporation and certain of its wholly-owned subsidiaries closed on a Purchase and Sale Agreement pursuant to which the Company sold its respective equity interests in Resolute Aneth, LLC, the entity which holds all of Resolute's interest in Aneth Field, and certain other assets associated with Aneth Field operations, to an affiliate of Elk Petroleum Limited.

Under the terms of the Purchase and Sale Agreement, the buyer funded a performance deposit of $10 million which was creditable against the purchase price. In addition to the performance deposit, Resolute received cash consideration of $150 million at closing, subject to normal purchase price adjustments. Additionally, Resolute is entitled to receive additional cash consideration of up to $35 million if oil prices exceed certain levels in the three years after closing, as follows: buyer will pay Resolute $40,000 for each week day in the twelve months after closing that the WTI spot oil price exceeds $52.50 per barrel (up to $10 million); $50,000 for each week day in the twelve months following the first anniversary of closing that the oil price exceeds $55.00 per barrel (up to $10 million) and $60,000 for each week day in the twelve months following the second anniversary of closing that the oil price exceeds $60.00 per barrel (up to $15 million). As of closing, the fair value of the additional consideration was $16.0 million. The proceeds of the sale were used to reduce amounts outstanding under the Company's Revolving Credit Facility (as defined in Note 5) and for other corporate purposes. Under seller accounting for contingent consideration, the Company has determined that this arrangement meets the definition of a derivative. See Note 9 – Derivative Instruments for additional information regarding the contingent payment derivative instrument. As part of the sale, the Company is no longer liable for asset retirement obligations of $15.8 million and is no longer required to maintain a restricted cash balance with regards to Aneth Field asset retirement obligations. As the sale did not significantly alter the relationship between capital costs and proved reserves, no gain or loss was recognized.

In conjunction with the closing of the sale of Aneth Field, certain management members resigned from their positions effective January 1, 2018. In connection with their resignation, these individuals and the Company entered into separation agreements. The material terms of the separation agreements, including compensation payable thereunder and treatment of long-term incentive awards, are consistent with their respective employment agreements with the Company dated January 1, 2017 and various long-term incentive award agreements. As such, Resolute has accrued $2.2 million related to cash severance payments as of December 31, 2017. Effective January 1, 2018, all awards held were modified contemporaneously with the termination of their employment.

Divestiture of Southeast New Mexico Properties in the Permian Basin

In February 2017 the Company closed on the sale of its Denton and South Knowles properties in the Northwest Shelf project area in Lea County, New Mexico, for approximately $14.5 million in cash, subject to customary purchase price adjustments. The proceeds of the sale were used to reduce amounts outstanding under the Company's Revolving Credit Facility (as defined in Note 5) and for other corporate purposes. As part of the sale, the Company was also no longer liable for asset retirement obligations of $3.6 million at March 31, 2017.

Divestiture of Midstream Assets in the Delaware Basin

In July 2016 Resolute Southwest entered into a definitive Purchase and Sale Agreement (the "Mustang Agreement") with Caprock Permian Processing LLC and Caprock Field Services LLC, as buyers (collectively, "Caprock") pursuant to which Resolute Southwest and an existing minority interest holder (collectively, the "Sellers") agreed to sell certain gas gathering and produced water handling and disposal systems owned by them in the Mustang project area in Reeves County, Texas, ("Mustang") for a cash payment of $35 million, plus certain earn-out payments described below.

In July 2016 Resolute Southwest also entered into a definitive Purchase and Sale Agreement (the "Appaloosa Agreement") with Caprock, pursuant to which Resolute Southwest agreed to sell certain gas gathering and produced water handling and disposal systems owned by Resolute Southwest in the Appaloosa project area in Reeves County, Texas, ("Appaloosa") for a cash payment of $15 million, plus certain earn-out payments described below.

In August 2016 Resolute Southwest closed the transactions contemplated by the Mustang Agreement and the Appaloosa Agreement. Resolute Southwest received aggregate consideration of approximately $36 million (including earn-out payments earned as of the closing). As the sale did not significantly alter the relationship between capital costs and proved reserves, no gain or loss was recognized.

In July 2016, in connection with the Appaloosa Agreement and the Mustang Agreement, Resolute Southwest also entered into a definitive Earn-out Agreement (the "Earn-out Agreement"), pursuant to which Resolute Southwest will be entitled to receive certain earn-out payments based on drilling and completion activity in Appaloosa and Mustang through 2020 that will deliver gas and produced water into the system. Earn-out payments for each qualifying well will vary depending on the lateral length of the well and the year in which the well is drilled and completed. In March 2017 the Earn-out Agreement was amended by the parties to provide for an increase in earn-out payments for wells drilled and completed in 2017. Earn-out payments are contingent on future drilling, and therefore will be recognized when earned. In 2017, we earned $25.6 million of earn-out payments.

In connection with the closing of the transactions contemplated by the Appaloosa Agreement and the Mustang Agreement, Resolute Southwest entered into fifteen year commercial agreements with Caprock for gas gathering services and water handling and disposal services for all current and future gas and water produced by Resolute Southwest in Mustang and Appaloosa in exchange for customary fees based on the volume of gas and water produced and delivered. Resolute Southwest has agreed to dedicate and deliver all gas and water produced from its acreage in Mustang and Appaloosa to Caprock for gathering, processing, compression and disposal services for a term of fifteen years.

In April 2017, Resolute Southwest entered into a Crude Oil Connection and Dedication Agreement with Caprock Permian Crude LLC ("Caprock Crude"), an affiliate of Caprock. Pursuant to the agreement, Caprock Crude has constructed the gathering systems, pipelines and other infrastructure for the gathering of crude oil from our Mustang and Appaloosa operating areas in exchange for customary fees based on the volume of crude oil produced and delivered. Resolute Southwest has agreed to dedicate and deliver all crude oil produced from its acreage in Mustang and Appaloosa to Caprock Crude for gathering for a term through July 31, 2031, coterminous with our other commercial agreements with Caprock. For the first five years of the agreement, the crude oil will be delivered to Midland Station under a joint tariff arrangement between Caprock Crude and Plains Pipeline, L.P. In April 2017, Resolute Southwest also entered into a Crude Oil Purchase Contract with Plains Marketing, L.P. ("Plains") providing for the sale to Plains of substantially all of the crude oil produced from the Mustang and Appaloosa areas for a price equal to an indexed market price less a $1.75 differential that will cover the joint tariff payable to Caprock Crude under the Crude Oil Connection and Dedication Agreement.

Pro Forma Financial Information

The unaudited pro forma financial information for the years ended December 31, 2017 and 2016, respectively, gives effect to the divestiture of the Aneth Field, the Delaware Basin Firewheel Acquisition, and the sale of the Delaware Basin Midstream Assets as if each had occurred on January 1, 2016 (in thousands, except per share amounts):

	Year ended December 31,	
	2017	2016
Revenue	$229,045	$92,711
Income/(loss) from operations	44,128	(86,341)
Net loss available to common stockholders	(8,261)	(143,100)
Basic and diluted net loss per share	$(0.38)	$(9.15)

The pro forma financial information is presented for informational purposes only and is not indicative of the results of operations that would have been achieved if these acquisitions or divestitures had taken place at the beginning of the earliest periods presented or that may result in the future. The pro forma adjustments made utilize certain assumptions that Resolute believes are reasonable based on the available information.

Note 4 — Earnings per Share

The Company computes basic net income (loss) per share using the weighted average number of shares of common stock outstanding during the period. Diluted net income (loss) per share is computed using the weighted average number of shares of common stock and, if dilutive, potential shares of common stock outstanding during the period. Net income (loss) available to common stockholders is computed by deducting both the dividends declared in the period on preferred and the dividends accumulated for the period on cumulative preferred stock from net income.

Potentially dilutive shares consist of the incremental shares and options issuable under the Company's 2009 Performance Incentive Plan (the "Incentive Plan") as well as common shares issuable upon the assumed conversion of the Convertible Preferred Stock (as defined in Note 7). The treasury stock method is used to measure the dilutive impact of potentially dilutive shares.

The following table details the potential weighted average dilutive and anti-dilutive securities for the periods presented (in thousands):

	Twelve Months Ended December 31,		
	2017	2016	2015
Potential dilutive restricted stock	3,731	1,112	356
Anti-dilutive securities	3,731	3,365	980

The following table sets forth the 2017, 2016 and 2015 computation of basic and diluted net income (loss) per share of common stock for the periods presented (in thousands, except per share amounts):

	2017	2016	2015
Net loss available to common stockholders	$(7,708)	$(161,722)	$(742,279)
Accumulated undeclared dividends	—	(1,185)	—
Adjusted net loss available to common shareholders	(7,708)	(162,907)	(742,279)
Basic weighted average common shares outstanding	21,889	15,767	14,986
Add: dilutive effect of non-vested restricted stock	—	—	—
Diluted weighted average common shares outstanding	21,889	15,767	14,986
Basic and diluted net loss per common share	$(0.35)	$(10.33)	$(49.55)

Note 5 — Long Term Debt

As of the dates indicated, the Company’s long-term debt consisted of the following (in thousands):

	Principal	Unamortized premium/ (discount)	Unamortized deferred financing costs	December 31, 2017
Revolving credit facility	$30,000	$ —	$ (2,513)	$27,487
8.50% senior notes	525,000	2,222	(3,982)	523,240
Total long-term debt	$555,000	$ 2,222	$ (6,495)	$550,727

	Principal	Unamortized premium/ (discount)	Unamortized deferred financing costs	December 31, 2016
Revolving credit facility	$10,000	$ —	$ (1,179)	$8,821
Secured term loan facility	128,303	(4,882)	(1,282)	122,139
8.50% senior notes	400,000	985	(3,831)	397,154
Total	$538,303	$ (3,897)	$ (6,292)	$528,114
Current portion of secured term loan facility	128,303	(4,882)	(1,282)	122,139
Long-term debt	$410,000	$ 985	$ (5,010)	$405,975

For the years ended December 31, 2017, 2016 and 2015, the Company incurred interest expense on long-term debt of $43.4 million, $50.7 million and $64.4 million, respectively. Approximately $9.7 million in interest expense was incurred in 2017 as a result of the extinguishment of the Secured Term Loan Facility (as defined below) on January 3, 2017. The Company capitalized $15.8 million, $4.1 million and $6.0 million of interest expense during the years ended December 31, 2017, 2016 and 2015, respectively.

Revolving Credit Facility

In February 2017, the Company entered into the Third Amended and Restated Credit Agreement with a syndicate of banks led by Bank of Montreal, as Administrative Agent, Capital One, National Association, as syndication agent, and Barclays Bank PLC, ING Capital LLC and SunTrust Bank, as co-documentation agents (the "Revolving Credit Facility"). In connection with entering into the Revolving Credit Facility, the Company repaid all amounts outstanding under the Second Amended and Restated Credit Agreement, dated as of April 15, 2015, by and among Resolute Energy Corporation, as borrower, certain subsidiaries of Resolute Energy Corporation, as Guarantors (defined below), Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto, as amended, and terminated that agreement.

The Revolving Credit Facility specifies a maximum borrowing base as determined by the lenders sole discretion. The determination of the borrowing base takes into consideration the estimated value of Resolute's oil and gas properties in accordance with the lenders' customary practices for oil and gas loans. The borrowing base is redetermined semi-annually, and the amount available for borrowing could be increased or decreased as a result of such redeterminations. Under certain circumstances, either Resolute or the lenders may request an interim redetermination. The Revolving Credit Facility matures in February 2021, unless there is a maturity of material indebtedness prior to such date.

The Revolving Credit Facility includes covenants that require, among other things, Resolute to maintain a ratio of current assets to current liabilities of no less than 1.0 to 1.0 and a ratio of funded debt to EBITDA (as defined in the Revolving Credit Facility) of no more than 4.0 to 1.0. The Revolving Credit Facility also includes customary additional terms and covenants that place limitations on certain types of activities, hedging, the payment of dividends, and that require satisfaction of certain financial tests.

In October 2017, the Company entered into the Second Amendment to the Third Amended and Restated Credit Agreement. The Second Amendment, among other things, amended the definition of EBITDA to include customary transaction costs and expenses incurred in connection with any material acquisition or disposition, provided for certain amendments to the calculation of EBITDA for purposes of the Revolving Credit Facility. Additionally, the amended covenants prohibit us from entering into derivative arrangements during which such derivative arrangements are in effect for more than (i) for the first year, the greater of 85% of anticipated projected production from proved properties or 75% of our anticipated projected production from properties, (ii) for the second year, 85% of anticipated projected production from proved properties and (iii) for the period after such two year period, the greater of 75% of our anticipated projected production from proved properties or 85% of our anticipated projected production from proved developed producing properties after such two year period (not to exceed a term of 60 months for any such derivative arrangement). Furthermore, the Second Amendment reaffirmed the borrowing base at $218.8 million. Upon the consummation of the disposition of the Aneth Field Properties, the borrowing base was automatically reduced to $210 million. Lastly, the amendment provided that the borrowing base shall automatically be reduced by 25% of all unsecured indebtedness of the Company in excess of $550 million. Resolute was in compliance with the terms and covenants of the Revolving Credit Facility at December 31, 2017.

As of December 31, 2017, outstanding borrowings under the Revolving Credit Facility were $30 million with a weighted average interest rate of 4.44%, under a borrowing base of $210 million. The borrowing base availability had been reduced by $2.8 million in conjunction with letters of credit issued at December 31, 2017.

To the extent that the borrowing base, as adjusted from time to time, exceeds the outstanding balance, no repayments of principal are required prior to maturity. However, should the borrowing base be set at a level below the outstanding balance, Resolute would be required to eliminate that excess within 120 days following that determination. The Revolving Credit Facility is guaranteed by all of Resolute’s subsidiaries and is collateralized by substantially all of the assets of the Company and its wholly-owned subsidiaries.

Each base rate borrowing under the Revolving Credit Facility accrues interest at either (a) the London Interbank Offered Rate (“LIBOR”), plus a margin that ranges from 3.0% to 4.0% or (b) the Alternative Base Rate defined as the greater of (i) the Administrative Agent’s Prime Rate (ii) the Federal Funds effective Rate plus 0.5% or (iii) an adjusted London Interbank Offered Rate plus a margin that ranges from 2.0% to 3.0%. Each such margin is based on the level of utilization under the borrowing base.

Secured Term Loan Agreement

In December 2014, Resolute and certain of its subsidiaries, as guarantors, entered into a second lien Secured Term Loan Agreement with Bank of Montreal, as administrative agent, and the lenders party thereto, pursuant to which we borrowed $150 million (the “Secured Term Loan Facility”). In May 2015 Resolute and certain of its subsidiaries, as guarantors, entered into an Amendment to the Secured Term Loan Agreement and Increased Facility Activation Notice-Incremental Term Loans with Bank of Montreal, as administrative agent, and the lenders party thereto, pursuant to which we borrowed an additional $50 million of Incremental Term Loans under the Secured Term Loan Facility.

In December 2015, the Company retired $70 million of the amount outstanding under the Secured Term Loan Facility following the sale of certain properties in the Midland Basin in accordance with mandatory prepayment provisions stipulated in the Secured Term Loan Facility.

In January 2017, the Company repaid approximately $132 million constituting all amounts due under the Term Loan Facility (including prepayment fees), with a portion of the proceeds from its common stock offering that closed on December 23, 2016. The Secured Term Loan Facility was terminated in connection with the repayment.

Senior Notes

In 2012 the Company consummated two private placements of senior notes with principal totaling $400 million (the “Original Senior Notes”). The Original Senior Notes are due May 1, 2020, and bear an annual interest rate of 8.50% with the interest on the Original Senior Notes payable semiannually in cash on May 1 and November 1 of each year.

In May 2017, the Company consummated a private placement of senior notes totaling an additional $125 million aggregate principal amount of the Company’s 8.50% Senior Notes due 2020 (the “Incremental Senior Notes”), under the same Indenture (the “Indenture”) as the Original Senior Notes that were previously issued (collectively referred to as the “Senior Notes”). The net proceeds of the offering of the Incremental Senior Notes, after reflecting the purchasers' discounts and commissions, and estimated offering expenses, were approximately $125.1 million. The closing of the Incremental Senior Notes occurred on May 12, 2017.

The Senior Notes were issued under an Indenture among the Company and all of the Company's subsidiaries, each of which is 100% owned by the Company (the "Guarantors") in a private transaction not subject to the registration requirements of the Securities Act of 1933. In March 2013 and July 2017 the Company registered the exchange of the Original Senior Notes and the Incremental Senior Notes, respectively, with the Securities and Exchange Commission pursuant to registration statements on Form S-4 that enabled holders of the Senior Notes to exchange the privately placed Senior Notes for registered Senior Notes with substantially identical terms. All of the Original Senior Notes and Incremental Senior Notes have been exchanged for publically registered Senior Notes. The Indenture contains affirmative and negative covenants that, among other things, limit the Company's and the Guarantors' ability to make investments, incur additional indebtedness or issue certain types of preferred stock, create liens, sell assets, enter into agreements that restrict dividends or other payments by restricted subsidiaries, consolidate, merge or transfer all or substantially all of the assets of the Company, engage in transactions with the Company's affiliates, pay dividends or make other distributions on capital stock or prepay subordinated indebtedness and create unrestricted subsidiaries. The Indenture also contains customary events of default. Upon occurrence of events of default arising from certain events of bankruptcy or insolvency, the Senior Notes shall become due and payable immediately without any declaration or other act of the trustee or the holders of the Senior Notes. Upon the occurrence of certain other events of default, the trustee or the holders of the Senior Notes may declare all outstanding Senior Notes to be due and payable immediately. The Company was in compliance with all financial covenants under its Senior Notes as of December 31, 2017.

The Senior Notes are general unsecured senior obligations of the Company and guaranteed on a senior unsecured basis by the Guarantors. The Senior Notes rank equally in right of payment with all existing and future senior indebtedness of the Company, will be subordinated in right of payment to all existing and future senior secured indebtedness of the Guarantors, will rank senior in right of payment to any future subordinated indebtedness of the Company and will be fully and unconditionally guaranteed by the Guarantors on a senior basis.

The Senior Notes are redeemable by the Company on not less than 30 or more than 60 days' prior notice, at a redemption price of 102.125%, reducing to 100.000% at May 1, 2018. If a change of control occurs, each holder of the Senior Notes will have the right to require that the Company purchase all of such holder's Senior Notes in an amount equal to 101% of the principal of such Senior Notes, plus accrued and unpaid interest, if any, to the date of the purchase.

The fair value of the Senior Notes at December 31, 2017, was estimated to be $535.1 million based upon data from independent market makers (Level 2 fair value measurement).

Note 6 — Income Taxes

The following table summarizes the components of the provision for income taxes (in thousands):

	2017	2016	2015
Current income tax benefit (expense)	$293	$(91)	$—
Deferred income tax benefit	—	—	22,354
Total income tax benefit (expense)	$293	$(91)	$22,354

The provision for income taxes for the years ended December 31, 2017, 2016 and 2015 differs from the amount that would be provided by applying the statutory maximum U.S. federal corporate income tax rate of 35% to income before income taxes. This difference relates primarily to state income taxes and estimated permanent differences as follows (in thousands):

	2017	2016	2015
Expected statutory income tax benefit	$534	$56,571	$267,621
State income tax benefit (expense)	(116)	3,087	13,394
Change in state tax rate	(2,466)	—	—
Equity compensation	34	(2,761)	(4,822)
Non-deductible executive compensation	(3,825)	(690)	—
Prior year true up	1,745	—	—
Tax credits	1,034	—	—
Other	1,636	(293)	(247)
Change in corporate tax rate (1)	(114,786)	—	—
Valuation allowance	116,503	(56,005)	(253,592)
Total income tax benefit (expense)	$293	$(91)	$22,354

(1) The change in the statutory maximum U.S. federal corporate income tax rate was enacted in December 2017 by Public Law No. 115-97, commonly referred to as the Tax Cuts and Jobs Act (the "Tax Act"), effective for taxable years beginning on or after January 1, 2018. The Tax Act resulted in the Company generating a deferred tax expense primarily due to the reduction in the U.S. statutory corporate income tax rate from a maximum 35% to a flat 21% rate. This deferred tax expense was offset by the valuation allowance placed on the Company's deferred tax assets. Based on the Company's current interpretation and subject to the release of regulations promulgated by the U.S. Department of Treasury and any other future interpretive guidance relating to the Tax Act, the Company believes the effects of the change in U.S. federal income tax laws incorporated herein are substantially complete.

The tax effects of temporary differences that give rise to significant portions of the deferred income tax assets and liabilities are presented below (in thousands):

	December 31,	
	2017	2016
Deferred income tax assets (liabilities):		
Derivative financial instruments	4,683	4,403
Net operating loss carryovers	164,564	206,663
Asset retirement obligation	613	7,530
Startup and organization costs	51	104
Deferred acquisition costs	26	45
Percentage depletion	582	1,335
Property and equipment costs	12,323	75,267
Equity compensation	1,330	2,267
Tax credits	3,837	283
Other	5,084	11,700
Valuation allowance	(193,093)	(309,597)
Total long term assets (liabilities)	—	—
Net deferred tax asset (liability)	$—	$—

The Company has U.S. net operating loss carry forwards of $723.2 million at December 31, 2017, which will begin expiring in 2026. The Company assesses the recoverability of its deferred tax assets each period by considering whether it is more likely than not that all or a portion of the deferred tax assets will be realized. The Company considers all available evidence (both positive and negative) in determining whether a valuation allowance is required. As a result of the Company's analysis, it was concluded that as of December 31, 2017 and 2016 a valuation allowance should be established against the Company's deferred tax asset. The Company recorded a valuation allowance as of December 31, 2017 and 2016 of $193.1 million and $309.6 million, respectively, on its deferred tax assets. The Company will continue to monitor facts and circumstances in the reassessment of the likelihood that the deferred tax assets will be realized.

The Company adopted the accounting for uncertain tax positions per FASB ASC Topic 740, Accounting for Income Taxes, from inception. This guidance prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. This guidance requires that the Company recognize in our consolidated financial statements, only those tax positions that are “more-likely-than-not” of being sustained, based on the technical merits of the position. In accordance with ASC 740-10, the Company performs a comprehensive review of our material tax positions. This guidance had no effect on the Company's financial position, cash flows or results of operations at 2017, 2016 and 2015 as the Company had no unrecognized tax benefits. The Company's policy is to recognize interest and penalties related to uncertain tax positions in income tax expense. The Company has no accrued interest or penalties related to uncertain tax positions as of December 31, 2017, 2016 and 2015.

The Company is subject to the following material taxing jurisdictions: U.S. federal, Colorado, Texas and Utah. The tax years that remain open to examination by the Internal Revenue Service are the years 2014 through 2017. The tax years that remain open to examination by state taxing authorities are 2013 through 2017.

Note 7 — Stockholders’ Equity and Equity Based Awards

Preferred Stock

The Company is authorized to issue up to 1,000,000 shares of preferred stock, par value $0.0001 with such designations, voting and other rights and preferences as may be determined from time to time by the Board of Directors. At December 31, 2017 and 2016, the Company had 62,500 shares of preferred stock issued and outstanding.

In October 2016, the Company entered into a Purchase Agreement with BMO Capital Markets Corp. (“Initial Purchaser”), pursuant to which the Company agreed to issue and sell to Initial Purchaser 62,500 shares of the Company’s 8 % Series B Cumulative Perpetual Convertible Preferred Stock, par value $0.0001 per share (the “Convertible Preferred Stock”), which includes 7,500 additional shares of Convertible Preferred Stock issued pursuant to the exercise of the Initial Purchaser’s over-allotment option for an aggregate net consideration of $60 million, before offering expenses.

Each holder has the right at any time, at its option, to convert, any or all of such holder’s shares of Convertible Preferred Stock at an initial conversion rate of 33.8616 shares of fully paid and nonassessable shares of Common Stock, per share of Convertible Preferred Stock. Additionally, at any time on or after October 15, 2021, the Company shall have the right, at its option, to elect to cause all, and not part, of the outstanding shares of Convertible Preferred Stock to be automatically converted into that number of shares of Common Stock for each share of Convertible Preferred Stock equal to the conversion rate in effect on the mandatory conversion date as such terms are defined in the Certificate of Designation.

During 2017, preferred dividends of $5.2 million were paid. A preferred dividend of $1.3 million was declared on December 19, 2017, and paid on January 16, 2018, to holders of record at the close of business on January 1, 2018.

Common Stock

The authorized common stock of the Company consists of 45,000,000 shares. The holders of the common shares are entitled to one vote for each share of common stock. In addition, the holders of the common stock are entitled to receive dividends when, as and if declared by the Board of Directors. At December 31, 2017 and 2016, the Company had 22,527,652 and 21,932,842 shares of common stock issued and outstanding, respectively.

In May 2016, Resolute adopted a stockholder rights plan and in connection with such plan declared a dividend of one preferred share purchase right (a “Right”) for each outstanding share of common stock, par value $0.0001 per share. The Rights trade with, and are inseparable from, the common stock until such time as they become exercisable on the distribution date. The Rights are evidenced only by certificates that represent shares of common stock and not by separate certificates. New Rights will accompany any new shares of common stock we issue after May 27, 2016, until the earlier of the distribution date and the redemption or expiration of the rights.

Each Right allows its holder to purchase from the Company one one-thousandth of a share of Series A Junior Participating Preferred Stock (a “Preferred Share”) for $4.50, once the Rights become exercisable. Prior to exercise, the Right does not give its holder any dividend, voting or liquidation rights. The Rights will not be exercisable until 10 days after the public announcement that a person or group has become an “Acquiring Person” by obtaining beneficial ownership of 20% or more of our outstanding common stock, or, if earlier, 10 business days (or a later date determined by the Board before any person or group becomes an Acquiring Person) after a person or group begins a tender or exchange offer which, if completed, would result in that person or group becoming an Acquiring Person. The stockholder rights plan was approved by the Company’s stockholders at the 2017 annual meeting in May 2017.

In June 2016, Resolute filed a certificate of amendment to its certificate of incorporation to effect a reverse stock split of the Company's common stock, par value $0.0001 per share, at a ratio of 1-for-5 (the "Reverse Stock Split"). The certificate of amendment also reduced the number of authorized shares of common stock from 225,000,000 to 45,000,000. The Reverse Stock Split, including the certificate of amendment, was approved by stockholders at the Company's 2016 annual meeting of stockholders and by the Company's Board of Directors. All historical share amounts disclosed have been retroactively adjusted to reflect this Reverse Stock Split.

During the fourth quarter 2016, the Company issued 4.4 million shares of common stock in a public offering at $38.00 per share for net proceeds of $160.9 million, after deducting fees and estimated expenses. The net proceeds were used to repay outstanding borrowings under the Secured Term Loan Facility and Revolving Credit Facility.

Long-Term Employee Incentive Plan

The Company accounts for share-based compensation in accordance with FASB ASC Topic 718, Stock Compensation.

In July 2009 the Company adopted the 2009 Long Term Performance Incentive Plan ("Incentive Plan"), providing for long-term share-based awards intended as a means for the Company to attract, motivate, retain and reward directors, officers, employees and other eligible persons through the grant of awards and incentives for high levels of individual performance and improved financial performance of the Company. The share-based awards are also intended to further align the interests of award recipients and the Company's stockholders. The maximum number of shares of common stock that may be issued under the Incentive Plan is 4,901,548 (which includes the additional 620,000 shares under Amendment No. 2 to the Incentive Plan approved by the Company's stockholders in June 2015, the 1,000,000 shares under Amendment No. 3 to the Incentive Plan approved by the Company's stockholders in May 2016 and the 1,450,000 shares under Amendment No. 4 to the Incentive Plan approved by the Company's stockholders on May 2017).

In December 2017, as a result of the Aneth Disposition, certain awards of employees of the Company whose jobs were related to Aneth Field, and who chose to accept employment with the buyer, were modified. Per an employee communication letter dated December 5, 2017, the employees were encouraged to continue employment with Resolute through December 31, 2017 and with the buyer of Aneth Field through March 16, 2018. Upon satisfying these conditions, the vesting terms of the outstanding long-term awards for such employees would be accelerated. Under modification accounting, the modified awards are deemed to be new awards and the original unvested awards' expense was reversed and the new awards' expense will be amortized from the date of modification through vest date, March 16, 2018. The modification of the awards resulted in the accelerated vesting of 47,057 time-based restricted shares, 26,177 stock appreciation rights, 47,998 stock options, $552,813 of time-based restricted cash and $31,296 of performance-based restricted cash.

Furthermore, in January 2018, as a result of the Aneth Disposition, certain management members resigned from their positions effective January 1, 2018. In connection with their resignation, the individuals and the Company entered into separation agreements. All awards held were modified contemporaneously with the termination of their employment. See Note 12 for a description of the impact of the modification and long-term incentive award grants since December 31, 2017.

For the years ended December 31, 2017, 2016 and 2015, the Company recorded expense related to the Incentive Plan as follows (in thousands):

	Year Ended December 31,		
	2017	2016	2015
Time-based restricted stock awards	$5,800	$4,359	$9,067
TSR awards	5,106	996	2,848
Stock option awards	1,264	936	365
Stock appreciation awards	—	—	45
Total share-based compensation expense	12,170	6,291	12,325
Time-based restricted cash awards	2,716	3,409	959
Performance-based restricted cash awards	2,012	13,780	226
Cash-settled stock appreciation awards	11,776	17,737	—
Total cash-based compensation expense	16,504	34,926	1,185
Total Incentive Plan compensation expense	$28,674	$41,217	$13,510

As of December 31, 2017, the Company held unrecognized share-based compensation expense (in thousands) which is expected to be recognized over a weighted-average period as follows:

	Unrecognized Compensation Expense	Weighted Average Years Remaining
Time-based restricted stock awards	$ 10,443	2.1
TSR awards	5,112	2.2
Stock option awards	1,597	1.0
Total unrecognized compensation expense	$ 17,152	

Equity Awards

Equity awards consist of time-based and performance-based restricted stock and stock options under the Incentive Plan.

Time-Based Restricted Stock Awards

Shares of time-based restricted stock issued to employees generally vest in three equal annual installments at specified dates based on continued employment. Shares issued to non-employee directors vest in one year based on continued service. The compensation expense to be recognized for the time-based restricted stock awards was measured based on the Company's closing stock price on the dates of grant, utilizing estimated forfeiture rates between 0% and 15% which are updated periodically based on actual employee turnover. During the year ended December 31, 2017, the Company granted 397,967 shares of time-based restricted stock to employees and non-employee directors, pursuant to the Incentive Plan.

The following table summarizes the changes in non-vested time-based restricted stock awards for the period presented:

	2017	
	Shares	Weighted Average Grant Date Fair Value
Non-vested, beginning of period	151,781	$ 25.07
Granted	397,967	43.04
Vested	(126,931)	27.22
Forfeited	(15,330)	33.90
Non-vested, end of period	407,487	$ 41.62

The weighted average grant date fair value of shares granted during the years ended December 31, 2017, 2016 and 2015 was $43.04, $4.48 and $6.75, respectively.

TSR Awards

In February 2017 the Board and its Compensation Committee awarded performance-based restricted shares to senior employees and executive officers of the Company under the Incentive Plan. The restricted stock grants vest only upon achievement of thresholds of cumulative total shareholder return (“TSR”) as compared to a specified peer group (the “Performance-Vested Shares”). A TSR percentile (the “TSR Percentile”) is calculated based on the change in the value of the Company’s common stock between the grant date and the applicable vesting date, including any dividends paid during the period, as compared to the respective TSRs of a specified group of twelve peer companies. The Performance-Vested Shares vest in three installments to the extent that the applicable TSR Percentile ranking thresholds are met upon the one-, two- and three-year anniversaries of the grant date. Performance-Vested Shares that are eligible to vest on a vesting date, but do not qualify for vesting, become eligible for vesting again on the next vesting date. All Performance-Vested Shares that do not vest as of the final vesting date will be forfeited on such date.

The Board and its Compensation Committee also granted rights to earn additional shares of common stock upon achievement of a higher TSR Percentile (“Outperformance Shares”). The Outperformance Shares are earned in increasing increments based on a TSR Percentile attained over a specified threshold. Outperformance Shares may be earned on any vesting date to the extent that the applicable TSR Percentile ranking thresholds are met in three installments on the one-, two- and three-year anniversaries of the grant date. Outperformance Shares that are earned at a vesting date will be issued to the recipient; however, prior to such issuance, the recipient is not entitled to stockholder rights with respect to Outperformance Shares. Outperformance Shares that are eligible to be earned but remain unearned on a vesting date become eligible to be earned again on the next vesting date. The right to earn any unearned Outperformance Shares terminates immediately following the final vesting date. The Performance-Vested Shares and the Outperformance Shares are referred to as the “TSR Awards.”

The compensation expense to be recognized for the TSR Awards was measured based on the estimated fair value at the date of grant using a Monte Carlo simulation model and utilizes estimated forfeiture rates between 0% and 2% which are updated periodically based on actual employee turnover.

The valuation model for the performance-based awards used the following assumptions:

Grant Year	Average Expected Volatility	Expected Dividend Yield	Risk-Free Interest Rate
2017	49.07% - 108.21%	0%	0.83% - 1.45%

The following table summarized changes in non-vested TSR Awards for the period presented:

	2017	
	Shares	Weighted Average Grant Date Fair Value
Non-vested, beginning of period	97,561	$ 66.60
Granted	131,379	77.23
Vested	(97,561)	66.60
Forfeited	(935)	77.23
Non-vested, end of period	130,444	$ 77.23

In addition to the vested TSR awards above, 63,024 outperformance shares were also earned and vested during the year ended December 31, 2017, related to the TSR awards granted in 2014.

Stock Option Awards

Options issued to employees to purchase shares of common stock vest in three equal annual installments at specified dates based on continued employment with a ten year term. The compensation expense to be recognized for the option awards was measured based on the Company’s estimated fair value at the date of grant using a Black-Scholes pricing model as well as estimated forfeiture rates between 0% and 15%, no dividends, expected stock price volatility ranging from 63% to 67% and a risk free rate ranging between 1.75% and 2.27%.

The following table summarizes the changes in non-vested option awards for the period presented:

	2017			
	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value (in thousands)
Outstanding, beginning of period	1,052,513	$ 4.03		

Exercised	(118,199)	4.76		
Forfeited	(16,060)	3.51		
Outstanding, end of period	918,254	$ 3.95	7.9	$ 25,274
Exercisable, end of period	342,848	$ 4.58	7.8	$ 9,218

The weighted average grant date fair value of options granted during the years ended December 31, 2016 and 2015 was $1.93 and $4.60, respectively. No options were granted during 2017. The total intrinsic value for options exercised during the years ended December 31, 2017 and 2016, was $3.6 million and $0.5 million, respectively. No options were exercisable during the year ended December 31, 2015.

Liability Awards

Liability awards consist of awards that are settled in cash instead of shares, as discussed below. The fair value of those instruments at a single point in time is not a forecast of what the estimate fair value of those instruments may be in the future. As the fair value of the liability awards is required to be re-measured at each period end, amounts recognized in future periods will vary.

Cash-settled Stock Appreciation Rights

A stock appreciation right is the right to receive an amount in cash equal to the excess, if any, of the fair market value of a share of common stock on the date on which the right is exercised over its base price. The February 2016 grants of cash-settled stock appreciation rights hold base prices of $2.65 per share (as to 486,373 rights) and $2.915 per share (as to 1,216,479 rights). The awards granted to employees vest in three equal annual installments and have a ten-year term. The awards granted to non-employee directors vest in one year based on continued service and also have a ten-year term. The compensation expense to be recognized for the cash-settled stock appreciation rights was measured utilizing estimated forfeiture rates between 0% and 8% which will be updated periodically based on actual employee turnover, no dividends and expected price volatility and risk-free rates relative to the expected term. The fair value of the cash-settled stock appreciation rights as of December 31, 2017, was $49.6 million, of which $29.8 million has been expensed.

Time-Based Restricted Cash Awards

Awards of time-based restricted cash issued to employees vest in three equal annual increments at specified dates based on continued employment. Time-based restricted cash issued to non-employee directors vests in one year based on continued service. The compensation expense to be recognized for the time-based restricted cash awards was measured based on the cash value per unit ($1 per unit) on the date of grant and utilized estimated forfeiture rates between 0% and 25% which will be updated periodically based on actual employee turnover. The total estimated future liability of the time-based restricted cash awards as of December 31, 2017, was $9.6 million, of which $7.1 million has been expensed.

Performance-Based Restricted Cash Awards

The performance criteria for the performance-based restricted cash awards granted in May 2015 are based on future prices of the Company's common stock trading at or above specified thresholds. If and as certain stock price thresholds are met, using a 60 trading day average, various multiples of the performance-vested cash award will be attained. The first stock price hurdle was at $10.00 at which the award was payable at 1x, and the highest stock price hurdle was $40.00 at which the award was payable at a multiple of 6x. Interim hurdles and multiples between these end points are set forth in the governing agreements. As of December 31, 2017, all of the stock price hurdles up to $40.00 had previously been met. A time vesting element will apply to the performance-vested cash awards such that attained multiples will not be paid out earlier than upon satisfaction of a three-year vesting timetable from the date of grant. In order for an award to be paid, both the performance criteria and the time criteria would need to be satisfied. Once a time vesting date passes, the employee is entitled to be paid one third, two thirds or 100%, as applicable, of whatever multiples have been achieved provided the employee continues to be employed by the Company.

The estimated fair value of the performance-based restricted cash awards as of December 31, 2017, was $16.6 million of which $16.0 million has been expensed, based upon the three year vesting. The fair value was estimated using Black-Scholes option pricing model for a cash or nothing call, an estimated forfeiture rate of 5%, an average effective term of less than one year, no dividends and expected price volatility and risk-free rates relative to the expected term.

Note 8 — Asset Retirement Obligation

Resolute's estimated asset retirement obligation liability is based on estimated economic lives, estimates as to the cost to abandon the wells and facilities in the future, and federal and state regulatory requirements. The liability is discounted using a credit-adjusted risk-free rate estimated at the time the liability is incurred or revised that ranges between 7% and 12%. Revisions to the liability could occur due to changes in estimated abandonment costs or well economic lives, or if federal or state regulators enact new requirements regarding the abandonment of wells. Asset retirement obligations are valued utilizing Level 3 fair value measurement inputs.

The following table provides a reconciliation of Resolute's asset retirement obligations for the periods presented (in thousands):

	December 31,	
	2017	2016
Asset retirement obligations at beginning of period	$20,352	$19,238
Additional liability incurred / acquired	443	587
Accretion expense	1,367	1,790
Liabilities settled / sold	(20,292)	(1,088)
Revisions to previous estimates	917	(175)
Asset retirement obligations at end of period	2,787	20,352
Less: current asset retirement obligations	(540)	(895)
Long-term asset retirement obligations	$2,247	$19,457

Note 9 — Derivative Instruments

Commodity Derivative Instruments

Resolute enters into commodity derivative contracts to manage its exposure to oil and gas price volatility. Resolute has not elected to designate derivative instruments as hedges under the provisions of FASB ASC Topic 815, Derivatives and Hedging. As a result, these derivative instruments are marked to market at the end of each reporting period and changes in the fair value are recorded in the accompanying consolidated statements of operations. Gains and losses on commodity derivative instruments from Resolute's price risk management activities are recognized in other income (expense). The cash flows from derivatives are reported as cash flows from operating activities unless the derivative contract is deemed to contain a financing element. Derivatives deemed to contain a financing element are reported as financing activities in the consolidated statement of cash flows.

The Company utilizes fixed price swaps, basis swaps, option contracts and two- and three-way collars. These instruments generally entitle Resolute (the floating price payer in most cases) to receive settlement from the counterparty (the fixed price payer in most cases) for each calculation period in amounts, if any, by which the settlement price for the scheduled trading days applicable to each calculation period is less than the fixed strike price or floor price. The Company would pay the counterparty if the settlement price for the scheduled trading days applicable to each calculation period exceeds the fixed strike price or ceiling price. The amount payable by Resolute, if the floating price is above the fixed or ceiling price, is the product of the notional contract quantity and the excess of the floating price over the fixed or ceiling price per calculation period. The amount payable by the counterparty, if the floating price is below the fixed or floor price, is the product of the notional contract quantity and the excess of the fixed or floor price over the floating price per calculation period. A three-way collar consists of a two-way collar contract combined with a put option contract sold by the Company with a strike price below the floor price of the two-way collar. The Company receives price protection at the purchased put option floor price of the two-way collar if commodity prices are above the sold put option strike price. If commodity prices fall below the sold put option strike price, the Company receives the cash market price plus the variance between the two put option strike prices. This type of instrument captures more value in a rising commodity price environment, but limits the benefits in a downward commodity price environment. Basis swaps, when used in connection with fixed price swaps, fix the price differential between the NYMEX commodity price and the index price at which the production is sold.

As of December 31, 2017, the fair value of the Company's commodity derivatives was a net liability of $21.3 million (Level 2 fair value measurement).

The following table represents Resolute's commodity swap contracts as of December 31, 2017:

	Oil (NYMEX WTI)	
Remaining Term	Bbl per Day	Weighted Average Swap Price per Bbl
Jan – Dec 2018	3,744	$ 51.10

The following table represents Resolute's three-way commodity collar contracts as of December 31, 2017:

Oil (NYMEX WTI)				
Remaining Term	Bbl per Day	Weighted Average Short Put Price per Bbl	Weighted Average Floor Price per Bbl	Weighted Average Ceiling Price per Bbl
Jan – Dec 2018	3,252	$ 40.15	$ 49.38	$ 54.19

The following table represents Resolute's commodity option contracts as of December 31, 2017:

Oil (NYMEX WTI)		
Remaining Term	Bbl per Day	Sold Call Price
Jan – Dec 2018	1,100	$55.00
Jan – Dec 2019	1,100	$62.85

The following table represents Resolute's basis swap contract as of December 31, 2017:

Gas (Permian Basin El Paso)		
Remaining Term	MMBtu per Day	Weighted Average Price Differential per MMBtu
Jan – Dec 2018	18,000	$ 0.688

Subsequent to December 31, 2017, Resolute entered into additional commodity option contracts as summarized below:

Bought Call	Oil (NYMEX WTI) Bbl per Day	Bought Call Price
Feb – May 2018	1,100	$55.00

Sold Call	Oil (NYMEX WTI) Bbl per Day	Sold Call Price
Jan – Dec 2019	1,330	$65.00

Resolute does not offset the fair value amounts of derivative assets and liabilities with the same counterparty for financial reporting purposes. See Note 10 for the location and fair value amounts of Resolute's commodity derivative instruments reported in the consolidated balance sheets at December 31, 2017 and 2016.

The table below summarizes the location and amount of commodity derivative instrument gains and losses reported in the consolidated statements of income (in thousands):

	2017	2016	2015
Other income (expense):			
Commodity derivative settlements	$3,730	$88,010	$93,150
Mark-to-market loss	(9,385)	(107,794)	(16,658)
Commodity derivative instruments gain (loss)	$(5,655)	$(19,784)	$76,492

Contingent Payment Derivative Instrument

In conjunction with the Aneth Disposition in November 2017, Resolute is entitled to receive additional cash consideration of up to $35 million if index pricing targets, as defined in the purchase and sale agreement, are achieved at specified future dates (see Note 3). The contingent consideration will be paid yearly if the pricing exceeds the thresholds pursuant to the purchase and sale agreement. We have evaluated the contract and concluded that it meets the definition and requirements for accounting treatment as a derivative instrument. As of December 31, 2017, the fair value of the additional consideration was $17.9 million. Fair value is determined through an application of mathematical models and Monte Carlo simulations designed to provide fair value estimates utilizing probability measures and the relevant market index measures. The fair value will be adjusted at each future reporting period over the life of the instrument. Changes in the fair value are included as a component of contingent payment derivative instrument gain (loss) on our consolidated statements of operations. See Note 10 for the location and fair value amounts of Resolute's contingent payment derivative instrument reported in the consolidated balance sheet at December 31, 2017.

Credit Risk and Contingent Features in Derivative Instruments

Resolute is exposed to credit risk to the extent of nonperformance by the counterparties in the derivative contracts discussed above. All commodity derivative counterparties are current lenders under Resolute's Revolving Credit Facility. Accordingly, Resolute is not required to provide any credit support to its commodity derivative counterparties other than cross collateralization with the properties securing the Revolving Credit Facility. Resolute's commodity derivative contracts are documented with industry standard contracts known as a Schedule to the Master Agreement and International Swaps and Derivative Association, Inc. Master Agreement ("ISDA"). Typical terms for each ISDA include credit support requirements, cross default provisions, termination events, and set-off provisions. Resolute has set-off provisions with its lenders that, in the event of counterparty default, allow Resolute to set-off amounts owed under the Revolving Credit Facility or other general obligations against amounts owed for commodity derivative contract liabilities.

As all of the commodity derivative contracts by counterparty were in a net liability position as of December 31, 2017, the maximum amount of loss in the event of all counterparties defaulting is $0.

Resolute is exposed to credit risk to the extent of nonperformance by the buyer with respect to the contingent payment derivative discussed above. The buyer is contractually obligated to pay Resolute the earned contingent payments pursuant to the purchase and sale agreement.

Note 10 — Fair Value Measurements

FASB ASC Topic 820, Fair Value Measurements and Disclosures, defines fair value as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The guidance establishes market or observable inputs as the preferred sources of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. The guidance establishes a hierarchy for determining the fair values of assets and liabilities, based on the significance level of the following inputs:

- Level 1 – Quoted prices in active markets for identical assets or liabilities.
- Level 2 – Quoted prices in active markets for similar assets and liabilities, quoted prices for identical or similar instruments in markets that are not active and model-derived valuations whose inputs are observable or whose significant value drivers are observable.
- Level 3 – Significant inputs to the valuation model are unobservable.

An asset or liability subject to the fair value requirements is categorized within the hierarchy based on the lowest level of input that is significant to the fair value measurement. Resolute's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability. Following is a description of the valuation methodologies used by Resolute as well as the general classification of such instruments pursuant to the hierarchy.

As of December 31, 2017, Resolute's commodity derivative instruments were required to be measured at fair value on a recurring basis. Resolute used the income approach in determining the fair value of its derivative instruments, utilizing present value techniques for valuing its swaps and basis swaps and option-pricing models for valuing its options. Inputs to these valuation techniques include published forward index prices, volatilities, and credit risk considerations, including the incorporation of published interest rates and credit spreads. Substantially all of these inputs are observable in the marketplace throughout the full term of the contract, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace and are therefore designated as Level 2 within the valuation hierarchy.

As of December 31, 2017, Resolute's contingent payment derivative instrument was recorded at its discounted net present value, and will be re-measured each period end over the life of the instrument. Fair value is determined through an application of mathematical models and Monte Carlo simulations designed to provide fair value estimates utilizing probability measures and relevant market index measures. Changes in the fair value are included as a component of contingent payment derivative instrument gain (loss) on our Consolidated Statements of Operations. Inputs to these valuation techniques include published forward index prices, volatilities, and credit risk considerations, including the incorporation of published interest rates and credit spreads. Substantially all of these inputs are observable in the marketplace throughout the full term of the contract or can be derived from observable data and are therefore designated as Level 2 within the valuation hierarchy.

The following is a listing of Resolute's commodity and contingent payment derivative assets and liabilities required to be measured at fair value on a recurring basis and where they are classified within the hierarchy as of December 31, 2017 and December 31, 2016 (in thousands):

	Level 2	
	December 31, 2017	December 31, 2016

Assets		
Commodity derivative instruments, current	$526	$ 218
Contingent payment derivative instruments, current	8,311	—
Contingent payment derivative instruments, long term	9,635	—
Total assets	$18,472	$ 218
Liabilities		
Commodity derivative instruments, current	$20,822	$ 8,014
Commodity derivative instruments, long term	990	4,104
Total liabilities	$21,812	$ 12,118

Note 11 — Commitments and Contingencies

Operating Leases

Rental payments expensed under operating leases for office facilities were approximately $3.0 million, $3.0 million and $1.1 million during 2017, 2016 and 2015, respectively. Net rental payments expensed under operating leases were approximately $0.7 million, $1.7 million and $1.9 million during 2017, 2016 and 2015, respectively.

Future payments for the Company's office facilities and vehicle leases under these operating lease agreements, as of December 31, 2017, are as follows (in thousands):

Year	Office Lease Rentals	Vehicle Lease Rentals	Total
2018	$ 1,855	$ 303	$ 2,158
2019	1,403	250	1,653
2020	1,287	221	1,508
2021	1,308	181	1,489
2022 and thereafter	550	83	633
Total	$ 6,403	$ 1,038	$ 7,441

Note 12 — Subsequent Events

Long-term incentive award modification

In January 2018, as a result of the Aneth Disposition, certain management members resigned from their positions effective January 1, 2018. In connection with their resignation, the individuals and the Company entered into separation agreements. The material terms of the separation agreements, including compensation payable thereunder and treatment of long-term incentive awards, are consistent with their respective employment agreements with the Company dated January 1, 2017 and various long-term incentive award agreements. All awards held were modified contemporaneously with the termination of their employment. Therefore, the awards were measured using the relevant inputs as of January 1, 2018. All related expense was recognized immediately on modification as there was never a substantive service condition related to their termination. The modification of the awards resulted in the accelerated vesting of 27,669 time-based restricted shares, 182,366 stock appreciation rights, 80,375 stock options, $563,475 of time-based restricted cash and $161,669 of performance-based restricted cash. The 2018 impact of the acceleration of their long-term incentive awards will be share-based compensation expense of approximately $1.0 million and $0.1 million in less expense on the cash-based compensation awards.

2018 Long-term incentive award grant

In February 2018, the Board and its Compensation Committee approved long-term incentive awards to employees and nonemployee directors for 2018 on terms generally consistent with the 2017 grant (see Note 7) consisting of a combination of time-vesting restricted stock, performance-vesting restricted stock, and outperformance awards under the Incentive Plan. The 2018 long-term incentive awards to employees and non-employee directors consisted of grants of (i) 332,561 shares of time-vesting restricted stock to employees vesting in three equal annual installments on March 8 of 2019, 2020 and 2021, (ii) 29,058 shares of time-vesting restricted stock to non-employee directors vesting in one installment on February 13, 2019, (iii) 184,657 shares of performance-vesting restricted stock to employees vesting in three equal installments on March 8 of 2019, 2020 and 2021, and (iv) outperformance awards entitling employees to earn up to 184,657 shares in the future and vesting in three equal installments on March 8 of 2019, 2020 and 2021.

Note 13 — Supplemental Oil and Gas Information (unaudited)

Costs Incurred in Oil and Gas Property Acquisition, Exploration, and Development Activities

Costs incurred during 2017, 2016 and 2015 related to oil and gas property acquisition, exploration and development activities, including the fair value of oil and gas properties acquired are summarized as follows (in thousands):

	2017	2016	2015
Acquisition costs			
Proved	$20,590	$41,830	$—
Unproved	147,442	120,851	6,583
Exploration costs	175,254	101,719	13,764
Development costs*	133,066	31,057	39,883
Total	$476,352	$295,457	$60,230

*Includes $3.3 million, $5.9 million and $8.9 million of acquired CO_2 during 2017, 2016 and 2015, respectively.

Capitalized Costs of Oil and Gas Properties

Net capitalized costs related to Resolute's oil and gas producing activities at December 31, 2017 and December 31, 2016 were as follows (in thousands):

	2017	2016
Proved oil and gas properties	$2,030,316	$1,889,111
Unevaluated oil and gas properties, not subject to amortization	248,059	121,375
Accumulated depletion, depreciation and amortization	(1,730,204)	(1,640,279)
Oil and gas properties, net	$548,171	$370,207

Oil and Gas Reserve Quantities

The reserve data as of December 31, 2017, was prepared by Resolute. Netherland, Sewell & Associates, Inc. ("NSAI"), independent petroleum engineers, audited all properties. Users of this information should be aware that the process of estimating quantities of proved oil and gas reserves is very complex, requiring significant subjective decisions to be made in the evaluation of available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors, including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, revisions to existing reserves estimates may occur from time to time. Although every reasonable effort is made to ensure reserves estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various reservoirs make these estimates generally less precise than other estimates included in the financial statement disclosures.

Presented below is a summary of the changes in estimated reserves (in thousands):

	Oil (Bbl)	Gas (MMcf)	NGL (Bbl)	Oil Equivalent (Boe)[1]
Proved reserves as of January 1, 2015	63,715	36,798	4,370	74,218
Purchase of minerals in place	—	—	—	—
Production	(3,270)	(5,193)	(400)	(4,535)
Extensions, discoveries and other additions	1,965	8,208	1,269	4,602
Sales of minerals in place	(5,289)	(23,674)	(2,837)	(12,072)
Revisions of previous estimates	(28,373)	(2,279)	(341)	(29,093)
Proved reserves as of December 31, 2015	28,748	13,860	2,061	33,120
Purchase of minerals in place	1,492	5,810	863	3,323
Production	(3,821)	(4,811)	(559)	(5,182)
Extensions, discoveries and other additions	21,427	41,151	6,257	34,543
Sales of minerals in place	—	—	—	—
Revisions of previous estimates	(4,042)	(3,562)	(900)	(5,537)
Proved reserves as of December 31, 2016	43,804	52,448	7,722	60,267
Purchase of minerals in place	171	704	73	362
Production	(5,499)	(12,101)	(1,641)	(9,156)
Extensions, discoveries and other additions	14,170	60,330	7,394	31,619
Sales of minerals in place	(22,821)	(654)	(96)	(23,026)
Revisions of previous estimates	(4,506)	(5,913)	(1,143)	(6,636)
Proved reserves as of December 31, 2017	25,319	94,814	12,309	53,430
Proved developed reserves:				
As of December 31, 2017	12,274	46,827	6,136	26,215
As of December 31, 2016	30,026	24,209	3,595	37,656
As of December 31, 2015	25,672	7,098	1,019	27,874
Proved undeveloped reserves:				
As of December 31, 2017	13,045	47,987	6,173	27,215
As of December 31, 2016	13,778	28,238	4,127	22,611
As of December 31, 2015	3,076	6,761	1,043	5,246

(1) Boe is determined using one Bbl of oil or NGL to six Mcf of gas. In accordance with SEC and Financial Accounting Standards Board ("FASB") requirements, our estimated net proved reserves and standardized measure at

December 31, 2017, 2016 and 2015, were determined utilizing prices equal to the twelve-month unweighted arithmetic average using first day of the month prices, resulting in an average Plains Marketing, L.P. posted WTI oil price of $47.79, $39.25 and $46.79 per Bbl and an average Platts Gas Daily El Paso Permian Basin spot gas price of $2.62, $2.31, and $2.45 per MMBtu for the Permian Properties, respectively. Our estimated net proved reserves and standardized measure at December 31, 2016 and 2015 for the Aneth Properties, were determined utilizing prices equal to the respective twelve-month unweighted arithmetic average using the first day of the month prices, resulting in an average NYMEX WTI oil price of $42.75 and $50.28 per Bbl, and an average Platts Gas Daily El Paso San Juan Basin spot gas price of $2.33 and $2.46, respectively

Purchase of minerals in place

During 2017, purchases of minerals in place consisted of 362 MBoe net from 2 gross producing wells acquired in the Delaware Basin Bronco Acquisition, which closed in May 2017.

During 2016, purchase of minerals in place of 3,323 MBoe net were a result of additional ownership in certain existing Permian Basin wells acquired in the Delaware Basin Firewheel acquisition. This number includes 169 MBoe of 2016 production.

Production

Of the 2017 amount, 20% of the oil equivalent production or 1,816 MBoe (1,734 MBbl oil and 489 MMcf gas) was from Aneth Field properties prior to the divestiture in November, and 80% or 7,341 MBoe (3,765 MBbl oil, 11,612 MMcf gas and 1,641 MBbl NGL) was from the Permian Basin properties.

Of the 2016 amount, 44% of the oil equivalent production or 2,255 MBoe (2,132 MBbl oil and 739 MMcf gas) was from Aneth Field properties, and 56% or 2,927 MBoe (1,689 MBbl oil, 4,071 MMcf gas and 559 MBbl NGL) was from Permian Basin properties.

Of the 2015 amount, 51% of the oil equivalent production or 2,292 MBoe (2,172 MBbl oil and 717 MMcf gas) was from Aneth Field properties, 39% or 1,782 MBoe (973 MBbl oil, 2,523 MMcf gas and 389 MBbl NGL) was from Permian Basin properties, and 10% or 462 MBoe (125 MBbl oil, 1,954 MMcf gas and 11 MBbl NGL) was from Powder River Basin properties, prior to their divestiture in October.

Extensions, discoveries and other additions

Extensions, discoveries and other additions in 2017 consisted primarily of 10,741 MBoe net from 16 gross newly drilled Permian wells and 2,722 MBoe net from 7 gross completions of drilled but uncompleted ("DUC") locations acquired in the Delaware Basin Bronco Acquisition together with 11,939 MBoe net from 15 gross immediate offset proved undeveloped Permian locations. These numbers include 2,469 MBoe net of 2017 production. Also included in additions are 6,217 MBoe net of proved undeveloped reserves from 9 gross offset locations to Permian wells drilled prior to 2017 which were uneconomic under previous reports' SEC pricing.

Extensions, discoveries and other additions in 2016 are largely due to the Reeves County drilling program which, together with the acquisition of additional interests in Mustang, resulted in 13.9 MMBoe added to net proved developed producing from successful drilling of non-proved locations. Furthermore, these successful wells created additional proved undeveloped offset locations carrying 16.2 MMBoe net reserves. Additionally, 4.5 MMBoe of net proved developed non-producing and proved undeveloped reserves were added to Aneth Field in connection with newly identified compression and well deepening projects.

Extensions, discoveries and other additions in 2015 are associated with an additional 970 MBoe from successful drilling of non-proved locations and additional proved undeveloped offset locations carrying about 3,600 MBoe reserves.

Sales of minerals in place

Sales of minerals in place during 2017 consisted of 431 MBoe net from 36 gross producing wells in the Denton and Knowles South Fields New Mexico, which were divested in February 2017, plus 22,595 MBoe net from 371 gross producing wells, and their associated injectors, in the divestiture of Aneth Field. These numbers are net of 1,847 MBoe net of 2017 production, 32 MBoe net in Denton and Knowles South Fields, and 1,816 MBoe net in Aneth Field.

During 2015, sales of minerals in place of 12,072 MBoe net during 2015 consisted of 5,475 MBoe from 161 gross wells in the Powder River Basin, which was divested in October 2015, 1,698 MBoe from 54 gross wells in the Howard and Martin County properties, which was divested in May and 4,899 MBoe from 102 gross wells in the Gardendale Midland Basin, which was divested in December 2015. These numbers are net of 1,091 MBoe of 2015 production, 462 MBoe in the Powder River Basin, 86 MBoe in Howard and Martin counties, and 543 MBoe in Gardendale.

Revisions of previous estimates

Revisions of previous estimates of 6,636 MBoe during 2017 were a function of well performance resulting from interference between existing, mature producers and newly drilled wells. The 2018 development plan has been designed to minimize further interference.

During 2016, decreased in proved reserves of 5,537 MBoe net was associated with revisions of previous estimates that were primarily a result of reduced product pricing. The average NYMEX West Texas Intermediate oil benchmark price fell 15% from $50.28 per Bbl at December 31, 2015 to $42.75 per Bbl at December 31, 2016. This decrease in product pricing resulted in the deferral of a number of Aneth Field development projects decreasing proved undeveloped reserves by 3,660 MBoe or 66% of the total 2016 revisions of previous estimates.

During 2015, decreases in proved reserves of 29,093 MBoe net associated with revisions of previous estimates were primarily a result of reduced product pricing and management's decision to allocate more of its 2015 capital expenditures toward exploitation drilling of higher than expected rates-of-return horizontal wells in the Permian Basin and less capital towards development projects in Aneth Field. The average NYMEX West Texas Intermediate oil benchmark price fell 47% from $94.99 per Bbl at December 31, 2014 to \$50.28 per Bbl at December 31, 2015. This decrease in product pricing resulted in deferral of the Aneth CO_2 projects which decreased proved undeveloped reserves by 22,786 MBoe or 78% of the total 2015 revisions of previous estimates.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves:

The following summarizes the policies used in the preparation of the accompanying oil and gas reserves disclosures, standardized measures of discounted future net cash flows from proved oil and gas reserves and the reconciliations of standardized measures at December 31, 2017. The information disclosed is an attempt to present the information in a manner comparable with industry peers.

The information is based on estimates of proved reserves attributable to Resolute's interest in oil and gas properties as of December 31, 2017. Proved reserves are estimated quantities of oil and gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

The standardized measure of discounted future net cash flows from production of proved reserves was developed as follows:

1) Estimates were made of quantities of proved reserves and future periods during which they are expected to be produced based on year-end economic conditions.
2) The estimated future cash flows were compiled by applying average (based on the first day of the month) annual prices of oil and gas relating to Resolute's proved reserves to the year-end quantities of those reserves.
3) The future cash flows were reduced by estimated production costs, costs to develop and produce the proved reserves and abandonment costs, all based on year-end economic conditions.
4) Future income tax expenses were based on year-end statutory tax rates giving effect to the remaining tax basis in the oil and gas properties, other deductions, credits and allowances relating to Resolute's proved oil and gas reserves.
5) Future net cash flows were discounted to present value by applying a discount rate of 10%.

The standardized measure of discounted future net cash flows does not purport, nor should it be interpreted, to present the fair value of Resolute's oil and gas reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs and a discount factor more representative of the time value of money and the risks inherent in reserve estimates. The following summary sets forth Resolute's future net cash flows relating to proved oil and gas reserves based on the standardized measure prescribed by FASB ASC Topic 932:

	December 31,		
	2017	2016	2015
	(in thousands)		
Future cash inflows	\$1,623,000	\$1,800,000	\$1,293,000
Future production costs	(629,000)	(934,000)	(774,000)
Future development costs	(285,000)	(288,000)	(180,000)
Future income taxes	(3,000)	(1,000)	—
Future net cash flows	706,000	577,000	339,000
10% annual discount for estimated timing of cash flows	(273,000)	(233,000)	(140,000)
Standardized measure of discounted future net cash flows	\$433,000	\$344,000	\$199,000

The principal sources of change in the standardized measure of discounted future net cash flows are:

	December 31,		
	2017	2016	2015
	(in thousands)		
Standardized measure, beginning of year	$344,000	$199,000	$833,000
Sales of oil and gas produced, net of production costs	(136,000)	(82,000)	(181,000)
Net changes in prices and production costs	41,000	(106,000)	(917,000)
Purchases of minerals in place	5,000	10,000	—
Sales of minerals in place	(99,000)	—	(134,000)
Previously estimated development costs incurred during the year	16,000	22,000	33,000
Extensions, discoveries and improved recovery	108,000	268,000	13,000
Changes in estimated future development costs	213,000	12,000	119,000
Revisions of previous quantity estimates	(71,000)	(3,000)	196,000
Accretion of discount	25,000	20,000	70,000
Net change in income taxes	(1,000)	—	104,000
Changes in timing and other	(12,000)	4,000	63,000
Standardized measure, end of year	$433,000	$344,000	$199,000

Note 14 — Quarterly Financial Data (unaudited)

The following is a summary of the unaudited financial data for each quarter for the years ended December 31, 2017 and 2016 (in thousands except per share data). Certain prior period amounts have been reclassified to conform to the current period presentation.

	Three Months Ended			
	March 31, 2017	June 30, 2017	September 30, 2017	December 31, 2017
Year Ended December 31, 2017:				
Revenue	$64,592	$70,260	$ 79,371	$ 89,255
Operating expenses	(56,202)	(55,847)	(71,742)	(75,668)
Income from operations	8,390	14,413	7,629	13,587
Net income (loss) available to common shareholders	76	10,690	(14,602)	(3,872)
Income (loss) per common share:				
Basic	$0.01	$0.49	$ (0.71)	$ (0.18)
Diluted	$0.01	$0.47	$ (0.71)	$ (0.18)
Weighted average common shares outstanding:				
Basic	21,738	21,917	21,941	21,958
Diluted	22,791	22,894	21,941	21,958

	Three Months Ended			
	March 31, 2016	June 30, 2016	September 30, 2016	December 31, 2016
Year Ended December 31, 2016:				
Revenue	$19,002	$35,390	$ 47,419	$ 62,667
Operating expenses	(95,086)	(39,767)	(57,089)	(64,042)
Loss from operations	(76,084)	(4,377)	(9,670)	(1,375)
Net loss available to common shareholders	(85,312)	(36,906)	(18,856)	(20,648)
Loss per common share:				
Basic and Diluted	$(5.65)	$(2.44)	$ (1.24)	$ (1.23)
Weighted average common shares outstanding:				
Basic and Diluted	15,036	15,155	15,173	17,690