Resolute Energy Corp
Form 10-K
March 13, 2017

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D. C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2016

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, Suite 2800	
Denver, CO	80203

(Address of principal executive offices) (Zip Code)

(303) 534-4600

(Registrant's telephone number, including area code)

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

Title of Each Class	Name of Exchange on Which Registered
Common 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 Section 15 of the Exchange 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 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, indefinite 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 or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting 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

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, 2016, computed by reference to the price at which the common stock was last sold as posted on the New York Stock Exchange, was $42.4 million.

As of February 28, 2017, 22,437,470 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 2017 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 words "anticipate," "intend," "believe," "estimate," "project," "expect," "plan," "should" or similar expressions are intended to identify such statements. Forward-looking statements included in this report relate to, among other things, the anticipated closing date and expected benefits of the Delaware Basin acquisitions, our production and cost guidance for 2017; anticipated capital expenditures in 2017 and the sources of such funding; availability of alternative oil purchase markets and oil takeaway systems; our financial condition and management of the Company in the current commodity price environment; future financial and operating results; our intention to evaluate and pursue the disposition of our Aneth Field properties, joint ventures and asset sales; liquidity and availability of capital including projections of free cash flow; additional future potential full cost ceiling impairments; future borrowing base adjustments and the effect thereof; future production, reserve growth and decline rates; our plans and expectations regarding our development activities including drilling, deepening, recompleting, fracing and refracing wells, the number of such potential projects, locations and productive intervals, the rates of return on our acreage and projects; the prospectivity of our properties and acreage; 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:

- our ability to consummate and to realize the expected benefits from the interests acquired in the Delaware Basin acquisitions;
- 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;
- 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 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;
- our ability to achieve the growth and benefits we expect from our acquisitions;
- 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;
- the success of the development plan for and production from our oil and gas properties;
- risks associated with rising interest rates;
- risks associated with all of our Aneth Field oil production being purchased by a single customer and connected to such customer with a pipeline that we do not own or control;

- inaccuracies in reserve estimates;
- the completion, timing and success of drilling on our properties;
- 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;
- our relationship with the Navajo Nation, the local community in the area where we operate Aneth Field, and Navajo Nation Oil and Gas Company, as well as certain purchase rights held by Navajo Nation Oil and Gas Company;

- the impact of any U.S. or global economic recession;
- the timing and amount of future production of oil and gas;
- the ability to sell or otherwise monetize assets, including our Aneth Field 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;
- 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, including changes in Navajo Nation laws, 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;
- regulation of waste water injection intended to address seismic activity;
- the concentration of our producing properties in a limited number of geographic areas;
- 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;
- anticipated CO_2 supply, which is currently sourced exclusively from Kinder Morgan CO_2 Company, L.P. under a contract with take or pay obligations;
- the effectiveness and results of our CO_2 flood program at Aneth Field;
- potential changes in income tax deduction 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 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 Aneth compression facility;
- 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 24-hour peak IP rates, 30-day peak IP rates, 90-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. 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 rate 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 6,500 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" refer to Predecessor Resolute (as defined below in "Selected Financ Data") for all periods prior to September 25, 2009, and Resolute Energy Corporation and its subsidiaries for all periods thereafter.

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. Our asset base is comprised primarily of properties in the Delaware Basin in west Texas (the "Permian Properties" or "Permian Basin Properties") and Aneth Field located in the Paradox Basin in southeast Utah (the "Aneth Field Properties" or "Aneth Field"). Our development activity is focused on our 20,000 gross (16,400 net) operated acreage position 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 opportunistic bolt-on acquisitions in the Delaware Basin while continuing to focus on improving margins in our Paradox Basin properties while de-risking certain future growth projects through selectively targeted capital investment.

During 2016 oil sales comprised approximately 90% of revenue, and our December 31, 2016, estimated net proved reserves were approximately 60.3 million barrels of oil equivalent ("MMBoe"), of which approximately 62% and 59% were proved developed reserves and proved developed producing reserves ("PDP"), respectively. Approximately 73% of our estimated net proved reserves were oil and approximately 85% were oil and natural gas liquids ("NGL"). The December 31, 2016, pre-tax present value discounted at 10% ("PV-10") of our net proved reserves and the standardized measure of our estimated net proved reserves were $344 million. For additional information about the calculation of our PV-10 and standardized measure, please read "Business and Properties — Estimated Net Proved Reserves."

For 2016, our Board of Directors approved a capital budget of between $115 million and $135 million, primarily focused on continuing horizontal development of our Delaware Basin Wolfcamp resource base in Reeves County, Texas, (the "Reeves County Assets") where we planned to drill and complete a total of nine wells. Capital spending in Aneth Field was limited to acquisition of CO2, upgrades in electrical infrastructure and basic field maintenance. The drilling success achieved in our Reeves County Assets during the first half of 2016 led us to expand our 2016 drilling program by adding five additional wells (for a total of fourteen wells during 2016). Because these additional wells were drilled in the third and fourth quarters, they did not materially contribute to aggregate 2016 production. However, these wells added to our 2016 exit production rate and will provide momentum to our 2017 production volumes. Our 2016 capital plan reflected our intention to make investments in assets that are accretive to net asset value at current prices and to grow proved reserves and production that will benefit the Company as we move through 2017.

For 2017, we expect to incur capital expenditures of $210 to $240 million, primarily focused on following our successful 2016 performance in the Delaware Basin with a two rig drilling program spudding 22 gross wells. We expect the 2017 program to accomplish a number of important initiatives for the Company. We will further delineate our development inventory as we drill wells across our acreage block, conduct multiple spacing tests and complete wells in multiple landing zones in the Wolfcamp A as well as in the Wolfcamp B. The success of this program will help confirm the more than 370 Wolfcamp A and B development locations we believe exist in our Mustang and Appaloosa project areas. We also expect that substantially all of our acreage will be held by production by the end of

2017.

We expect to outspend our cash flows from operations during 2017. A deterioration of commodity prices from current levels could negatively impact our results of operations, financial condition and future development plans. We may decrease our 2017 capital investment forecast during the year as a result of, among other things, a decline in commodity prices, drilling results, cost increases, or unfavorable changes in our borrowing capacity. We may also change our capital expenditure plan depending upon our ability to consummate the Delaware Basin Orla Acquisition (defined below) and/or the potential divestiture of our Aneth Field assets described below.

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, subject to customary purchase price adjustments (the “New Mexico Sale”). The effective date of this sale is October 1, 2016. The proceeds of the sale will be used for general corporate purposes.

On March 3, 2017, Resolute Natural Resources Southwest, LLC (“Buyer”), a wholly-owned subsidiary of the Company, entered into a Purchase and Sale Agreement (the “Purchase Agreement”) with undisclosed private sellers (“Sellers”) pursuant to which Buyer agreed to acquire certain producing and undeveloped oil and gas properties in the Delaware Basin in Reeves County, Texas (the “Delaware Basin Orla Acquisition”).

Consideration for the acquisition will be $160 million in cash, subject to customary purchase price adjustments. The closing of the acquisition is expected to occur on or about May 15, 2017, and is subject to the satisfaction or waiver of certain customary conditions, including the material accuracy of the representations and warranties of Buyer and Sellers, and performance of covenants. The Delaware Basin Orla Acquisition has an effective date of May 1, 2017. The Purchase Agreement contains terms and conditions customary to transactions of this type. Subject to the right of Buyer to be indemnified for certain liabilities for a limited period of time and for breaches of representations, warranties and covenants, Buyer will assume substantially all liabilities associated with the acquired properties. The Purchase Agreement also contains certain customary termination rights for each of Buyer and Sellers.

The properties to be acquired include approximately 4,600 net acres in Reeves County, Texas, 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. In addition, the Company will acquire interests in (i) two operated 4,500 foot lateral horizontal Wolfcamp wells that currently produce approximately 800 net Boe per day, (ii) six operated drilled but uncompleted Wolfcamp wells, four of which have lateral lengths of approximately 4,500 feet and two with approximately 7,500 foot laterals; and (iii) one non-operated 10,000 foot lateral Wolfcamp A well that is currently drilling.

To complete our repositioning as a pure-play Delaware Basin company, Resolute’s board of directors has directed management to explore and take preparatory steps toward a disposition of the Company’s Aneth Field assets. The potential disposition of Aneth Field, if consummated, would provide meaningful additional capital to Resolute. This capital can be deployed either to our Delaware Basin drilling program where we see our highest rates of return or as a component of the optimal long-term financing for the Delaware Basin Orla Acquisition.

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 2017 our board of directors approved a two rig drilling program spudding 22 gross wells. Upon closing the Delaware Basin Orla Acquisition, we plan to complete six drilled but uncompleted wells on the acquired properties sequentially and will evaluate adding a third rig in the second half of 2017 to accelerate the development of the acquired properties.

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 five year operating history in the Delaware Basin and our strong technical team to identify the best opportunities. The Delaware Basin Firewheel Acquisition (defined below) and the recently announced Delaware Basin Orla Acquisition represent examples of such opportunities.

Focus on the Profitability of Aneth Field. We will continue to focus on cost control and production maintenance in our Aneth Field Properties. In addition, we expect to develop a strategy to de risk additional growth opportunities in the field. To complete our repositioning as a pure-play Delaware Basin company, Resolute’s board of directors has directed management to explore and take preparatory steps toward a disposition of the Company’s Aneth Field assets.

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 increased production in lower cost areas and divestitures of higher cost properties, (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.

Divest of Non Core Assets. We entered into a Purchase and Sale Agreement to sell our producing properties in southeast New Mexico for a purchase price of $14.5 million. The closing of the sale occurred on February 22, 2017, effective as of October 1, 2016. These non core assets did not contribute to our organic growth strategy. The net proceeds were used to reduce leverage, which we expect will ultimately enable us to accelerate drilling in Reeves County. We intend to continue our evaluation and execution of additional non-core asset sales, when and as appropriate.

Strategically Use Equity to Manage Leverage. The Delaware Basin Firewheel Acquisition (defined below) was financed with a significant issuance of both common and convertible preferred equity. With respect to the recently announced Delaware Basin Orla Acquisition, we anticipate that the ultimate financing may have components of long-term debt and equity, although we are still evaluating the optimal financing structure, particularly in light of our recent decision to explore a potential divestiture of Aneth Field. As we look at additional acquisition opportunities, we will continue to consider the possibility of utilizing equity as consideration or a financing component.

Competitive Strengths

We have a number of strengths that we believe will help us successfully execute our 2017 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. Based only on zones that have established production from our nearby horizontal wells, we have identified a substantial inventory of more than 370 gross horizontal well locations in the Wolfcamp A and B. Upon closing the Delaware Basin Orla Acquisition, we expect that inventory to increase substantially. We believe that this inventory will allow us to grow our reserves and production, while generating attractive rates of return at current commodity price levels and our current projected cost structure. Recent developments in the area lead us to conclude that we may be able to increase our drilling opportunity inventory through tighter spacing and increasing the number of productive horizons above and below existing producing zones.

Operational Staff with Deep Expertise; Operating Control of Our Properties. 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, particularly in Reeves County. The work of our drilling team has led to reductions in drilling days and larger completion designs which we believe ultimately result in more productive and economic wells. 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. Further, operatorship of our Reeves County Assets is secured for the foreseeable future, as approximately 77% of the gross acreage is held by production.

Stable Long lived Oil Production from Aneth Field. Our field staff has been operating Aneth Field since before its purchase by the Company. Aneth Field has exhibited a long, shallow decline. With only modest capital expenditures, production has remained essentially flat over the last eight quarters. Additionally, our operating teams have found ways to reduce operating costs more than 25% since the second quarter of 2014. Because Aneth Field is held by production, it can serve as a long term source of production and cash flow.

Summary Reserve Information

The following table presents summary information related to our estimated net proved reserves that are derived from our December 31, 2016, reserve report, which were prepared by Resolute and audited by Netherland, Sewell & Associates, Inc. (“NSAI”), independent petroleum engineers.

	Estimated Net Proved Reserves at December 31, 2016 (MMBoe)	
	ProvedProved	2016 Net Daily

	Developed Producing	Developed Non-Producing	Proved Undeveloped	Total Proved	Production (Boe per day)
Aneth Field Properties	19.9	2.4	2.1	24.4	6,161
Permian Properties	15.4	—	20.5	35.9	7,996
Total	35.3	2.4	22.6	60.3	14,157

Future operating costs ($ millions)	$756.6
Future production taxes ($ millions)	175.4
Future capital costs ($ millions)	287.9
Future operating costs ($/Boe)	12.6
Future production taxes ($/Boe)	2.9
Future capital costs ($/Boe)	11.5

Description of Properties

Permian Basin Properties

As of December 31, 2016, we had interests in approximately 23,900 gross (20,000 net) acres in the Permian Basin of Texas and southeast New Mexico. Approximately 35.9 MMBoe of proved reserves are associated with these assets as of December 31, 2016.

During the year, we completed 14 gross (12.0 net) wells in the Permian Basin Properties and had 86 gross (76.7 net) producing wells at year-end 2016. As of December 31, 2016, we were in the process of drilling 1 gross (1.0 net) well and had 1 gross (1.0 net) well awaiting completion operations. During 2016, average net daily production from the Permian Basin Properties was 7,996 equivalent barrels of oil (“Boe”) and was 77% liquids. See “Business and Properties – Marketing and Customers” for more information on how production from this area is sold.

Delaware Basin Project. The Delaware Basin is our principal project area and includes approximately 20,000 gross (16,400 net) acres. The primary objective in this area is the Wolfcamp formation, particularly the Wolfcamp A and B subzones. Near our project area other operators are also developing the Wolfcamp C and D subzones, the X/Y and the Third Bone Spring formation. Based on drilling activity to date, approximately 77% of the gross acreage is held by production. Approximately 35.4 MMBoe of proved reserves are associated with these assets as of December 31, 2016. We believe that growth potential exists from more than 370 gross prospective wells targeting upper Wolfcamp A, lower Wolfcamp A and upper Wolfcamp B formations, which includes twenty proved undeveloped locations. We believe that significant additional opportunity exists from reduced spacing as well as additional subzones. For 2017, the Board has approved a two rig drilling program spudding 22 gross wells (provided that this program does not take into account additional potential drilling following the anticipated consummation of the Delaware Basin Orla Acquisition).

Divestiture of Southeast New Mexico Properties in the Permian Basin. In February 2017 we sold our Denton and South Knowles properties in the Northwest Shelf project area in Lea County, New Mexico, for approximately $14.5 million, subject to customary purchase price adjustments (the “New Mexico Sale”). The closing of the New Mexico Sale occurred on February 22, 2017, with an effective date of October 1, 2016. The proceeds of the sale will be used for general corporate purposes.

Acquisition of Reeves County Properties in the Delaware Basin. 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 common stock of the Company, par value $0.0001 per share, issued to Firewheel Energy, LLC (“Firewheel”) upon the closing of the purchase of the Firewheel properties (the “Firewheel Properties”) in the Delaware Basin (the “Delaware Basin Firewheel Acquisition”).

Divestiture of Midstream Assets in the Delaware Basin. In July 2016 Resolute Natural Resources Southwest, LLC (“Resolute Southwest”), a wholly owned subsidiary of Resolute, 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 a then 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), of which approximately $2 million was placed in an escrow account for a period of time to secure Resolute’s indemnity obligations under the Mustang Agreement and the Appaloosa Agreement. As the sale did not significantly alter the relationship between capital costs and proved reserves, no gain or loss was recognized.

The net proceeds of the midstream sale were used to repay amounts outstanding under our Revolving Credit Facility (as defined below) and for general corporate purposes.

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. On March 10, 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 received.

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 and processing 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.

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.

Aneth Field Properties

Aneth Field, a giant legacy oil field in southeast Utah, holds 41% of our net proved reserves as of December 31, 2016, and accounted for 44% of our production during 2016, averaging 6,161 Boe per day, of which 95% was oil. We own a majority of the working interests in, and are the operator of, three federal production units covering approximately 44,000 gross acres which constitute the Aneth Field Properties. These are the Aneth Unit, the McElmo Creek Unit and the Ratherford Unit, in which we own working interests of 62.4%, 67.5% and 58.6%, respectively, at December 31, 2016. We had interests in and operated 376 gross (238.5 net) producing wells and 324 gross (204.4 net) active water and CO_2 injection wells.

Aneth Field was discovered in 1956 by Texaco and has produced approximately 448 million barrels ("MMBbl") of oil to date. Aneth Field covers a single geologic structure with production coming from Pennsylvanian age Ismay and Desert Creek formations. For operational reasons, it was divided into the three separate operating units. In 1985, Mobil Oil Corporation (now "ExxonMobil"), as the operator of McElmo Creek Unit, initiated a successful CO_2 enhanced oil recovery project that has been in operation since then, resulting in significant incremental oil reserve production from the McElmo Creek Unit. While there is some reservoir heterogeneity in Aneth Field, development of the reserves has been accomplished generally with well-tested methodologies, including drilling and infilling vertical wells, horizontal drilling, waterflood activities and CO_2 flooding.

The majority of our interests in the field were acquired through two separate transactions from each of Chevron Corporation and its affiliates ("Chevron") and ExxonMobil, in 2004 and 2006, respectively. In November 2004, our predecessor company acquired a 53% operating working interest in the Aneth Unit, a 15% non-operating working interest in the McElmo Creek Unit and a 3% non-operating working interest in the Ratherford Unit from Chevron (the "Chevron Properties"). In April 2006 our predecessor company acquired an additional 7.5% working interest in the Aneth Unit, a 60% operating working interest in the McElmo Creek Unit and a 56% operating working interest in the Ratherford Unit from ExxonMobil (the "ExxonMobil Properties"). In each transaction, the remaining available interest was acquired by Navajo Nation Oil and Gas Company ("NNOGC") in a strategic alliance that benefits both us and NNOGC. We have a Cooperative Agreement with NNOGC that outlines how future acquisitions in a defined area will be shared and divides responsibilities between the parties to assist in the efficient development of Aneth Field. Please read "Business and Properties — Relationship with the Navajo Nation."

In 2006, after becoming operator of the entire field, we began the infrastructure improvements required for us to expand the CO_2 flood to the Aneth Unit and began injecting CO_2 in 2007. Approximately 96 producing wells in the first four phases of this expansion are experiencing incremental oil production response due to the CO_2 flood. Production from the area covered by the first three phases of the Aneth CO_2 flood has increased by approximately 171% from 2006. During 2017 CO_2 injection will continue into the currently developed patterns of Phase 1, 2, 3 and 4.

The existing Aneth Unit CO_2 flood expansions and the projected CO_2 flood expansion in the Ratherford Unit are in the same field and producing formation as the existing McElmo Creek Unit CO_2 project. Initially, oil and gas reserves associated with expansions are classified as proved undeveloped ("PUD"). Following installation of the necessary infrastructure, these CO_2-related reserves are reclassified as proved developed non-producing ("PDNP"). Once a response is exhibited at a producing well, the tertiary reserves associated with that well are then reclassified to proved developed producing ("PDP").

We believe significant opportunity exists to increase production from existing proved reserves. We began recompleting the DC IIC in early 2010 with notable increases in production. This subzone was waterflooded by a previous operator, but was shut-in by the early 1980s due to high water cuts and low oil prices prevalent at the time, and has never been directly CO_2 flooded. We have reactivated the DC IIC as a waterflood with highly economic results and plan to implement a CO_2 flood in this zone. In the Ratherford Unit, we have two potential CO_2 flood projects, one targeting both the Desert Creek I and II zones and a second targeting primarily the Desert Creek I zone. In Aneth Field at December 31, 2016, we had estimated net proved reserves of 2.4 MMBoe classified as PDNP and 2.1 MMBoe classified as PUD. These reserves are largely comprised of newly identified compression and deepening projects.

Beyond those projects included in our proved reserves, we believe that there are opportunities to increase reserves and production in Aneth Field through infill drilling, projects designed to increase processing rates within the CO_2 floods and through technological improvements that may allow for greater recovery efficiency across the field. Projects in 2017 will be focused on testing these concepts for potential development.

CO_2 is available from McElmo Dome, the largest naturally occurring CO_2 source in the United States. McElmo Dome is operated by Kinder Morgan CO_2 Company, L.P. ("Kinder Morgan"), with whom we have a long-term contract, with CO_2 pricing based on a percentage of current NYMEX West Texas Intermediate ("WTI") oil prices. Aneth Field is connected directly to McElmo Dome through a 28 mile pipeline that we operate and in which we own a 68% interest. We believe our long-term contract with Kinder Morgan and our ownership and operatorship of the pipeline provide a high degree of certainty and visibility with regard to meeting our CO_2 supply needs. We are required to take, or pay for if not taken, 75% of the total of the maximum daily quantities for each month during the term of the Kinder Morgan contract. There are make-up provisions allowing any take-or-pay payments we make to be applied against future purchases for specified periods of time. At December 31, 2016, we have a credit of $0.2 million to be applied to future CO_2 purchases. We do not have the right to resell CO_2 required to be purchased under the Kinder Morgan contract.

Oil production from our Aneth Field is characterized as a light, sweet crude oil with an API gravity of 41 degrees. The field is connected by pipeline to a refinery located near Gallup, New Mexico, that is owned and operated by Western Refining Southwest, Inc., a subsidiary of Western Refining Inc. ("Western"). Western currently purchases all of the non-royalty oil production of Resolute and NNOGC from Aneth Field under a purchase agreement initially entered into in July 2014. On December 31, 2014, the Company entered into an amendment to the agreement, which provides for Resolute to receive a price equal to the NYMEX oil price minus a differential of $8.00 per barrel of oil. The amendment also extended the term of the agreement until March 31, 2015, and provided that the term would continue thereafter on a month-to-month basis until terminated by a party with ninety days prior notice. On December 8, 2015, the Company entered into a second amendment to the agreement, which provided for a reduction of the differential to $7.50 per barrel of oil. On May 9, 2016, the Company entered into a third amendment to the agreement which provided that Resolute and NNOGC will receive a price equal to NYMEX oil price minus a differential of $7.50 per barrel of oil for the first 6,000 barrels of oil purchased per day and differential of $5.50 per barrel for amounts in excess of 6,000 barrels per day, with such pricing effective on May 1, 2016. In 2016, Western entered into a pre-merger agreement with Tesoro Corporation. Upon closing of this agreement, we do not anticipate that our business relationship will be negatively impacted; however, we cannot provide assurance of such conclusion. If, for any reason, Western is unable to process our oil, there is alternative access to markets through rail and truck facilities or through the FERC-regulated Texas-New Mexico pipeline owned by Western. Furthermore, oil can be trucked to the refineries or oil pipelines in southern New Mexico, west Texas or Salt Lake City, Utah.

Resolute is party to a cooperative agreement with NNOGC related to the Aneth Field Properties (the "Cooperative Agreement"). Pursuant to the Cooperative Agreement, as modified on March 9, 2017, NNOGC holds an option to purchase an additional 10% of Resolute's interest in the Aneth Field Properties. The option is exercisable until July 2017 at the fair market value of such interest.

The following table presents, as of December 31, 2016, our estimate of the future capital expenditures, net to our interest, for purchases of CO_2 required to implement compression upgrades in the McElmo Creek Unit through 2036. The table also presents the estimated net PDNP reserves that we anticipate will be produced as a result of this project, as included in our December 31, 2016, reserve report.

	Estimated Future Capital Expenditures (excluding CO_2)	Proved Reserves (MMBoe)	Estimated Future Development Cost ($/Boe, excluding CO_2)	Estimated Future CO_2 Purchases
	(in $ millions, except as otherwise indicated)			

McElmo Creek Unit — C5 Upgrade and New Compressor (PDNP)	$7.6	2.3	$ 3.28	$ 15.1

Aneth Field — Gas Compression. Currently there are two types of gas production in Aneth Field, saleable gas and gas that is contaminated by CO_2. The contaminated gas stream, which is rich in valuable NGL and gas, is currently compressed and re-injected into the reservoir. As we continue our CO_2 injection and expansion plans, the volume of contaminated gas will increase. During 2011, we completed rebuilding of the gas compression plant at Aneth Unit, which processes all contaminated gas from the expansion project. This plant dehydrates and recovers condensate from the recycled gas stream, and we are exploring options to expand the plant to separate CO_2 and hydrocarbon gas as well. If economically feasible, the hydrocarbon gas would be sold, adding income streams to the field economics while the separated CO_2 stream would be reinjected into the producing zone. The plant hydrocarbon extraction expansion project has been through early stages of engineering design and is currently on hold pending recovery of gas and NGL prices.

The saleable gas stream is currently transported to the San Juan Gas Plant in Fruitland, New Mexico. We are paid on a percent of proceeds basis that resulted in an average price of $1.31 per Mcf during 2016.

Divestiture of Wyoming Properties

In October 2015 we sold our Hilight Field interests in the Powder River Basin for approximately $55 million. The sale was consummated on October 6, 2015, with an effective date of July 1, 2015.

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, 2016, 2015 and 2014 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,		
	2016	2015	2014
Net proved developed reserves			
Oil (MBbl)	30,026	25,672	34,359
Gas (MMcf)	24,209	7,098	25,775
NGL (MBbl)	3,595	1,019	2,791
MBoe [1]	37,656	27,874	41,446
Net proved undeveloped reserves			
Oil (MBbl)	13,778	3,076	29,356
Gas (MMcf)	28,238	6,761	11,023
NGL (MBbl)	4,127	1,043	1,579
MBoe [1]	22,611	5,246	32,772
Total net proved reserves			
Oil (MBbl)	43,804	28,747	63,715
Gas (MMcf)	52,448	13,859	36,798
NGL (MBbl)	7,722	2,063	4,370
MBoe [1]	60,267	33,120	74,218
PV-10 ($ in millions) [2][3]	344	199	973
Discounted future income taxes ($ in millions)	—	—	(140)
Standardized measure ($ in millions) [2][4]	344	199	833

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, 2016, 2015 and 2014, were determined utilizing prices equal to the respective twelve-month unweighted arithmetic average using first day of the month prices, resulting in an average NYMEX WTI oil price of $42.75, $50.28 and $94.99 per Bbl for the Aneth Properties and Plains Marketing, L.P. posted WTI oil price of $39.25, $46.79 and $91.48 per Bbl for the Permian Properties, and an average Platts Gas Daily El Paso San Juan Basin spot gas price of $2.33, $2.46, and $4.31 per MMBtu for the Aneth Properties and Platts Gas Daily El Paso Permian Basin spot gas price of $2.31, $2.45, and $4.25 per MMBtu for the Permian Properties, 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, which, in the case of year-end 2016 estimates, are significantly lower than prevailing prices. 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 from 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 facility construction and well development activities began on CO_2 flood projects in Aneth Field in 2006, with CO_2 injection commencing in 2007 in Aneth Unit, and are ongoing although at reduced levels due to the current low commodity price environment. No CO_2 flood project proved undeveloped reserves were converted to proved developed in 2016.

Our operated drilling focus in 2016 was to preserve term leasehold acreage in the Permian Basin Properties primarily by targeting drilling on non-proved locations. During 2016, 22,491 gross MBoe of proved developed producing reserves were added to the proved reserves base through a successful blend of both operated and non-operated drilling of 15 gross non-proved locations in 2016 and late 2015, and through acquisition of additional ownership in those wells during 2016. No proved undeveloped reserves were converted into proved developed producing during 2016. An incremental 14 gross 2016 wells were drilled which, together with one later 2015 gross well, yielded total additions of 14,762 MBoe net of proved developed producing reserves and 17,957 MBoe net of proved undeveloped reserves through the addition of 20 gross immediate offset proved undeveloped Permian locations. These numbers include 907 MBoe of net proved producing reserves and 1,755 MBoe of net proved undeveloped reserves attributable to the acquisition of additional ownership in wells drilled, and existing leasehold, during 2016. These numbers also include 2016 production of 3,519 gross (2,214 net) MBoe.

Additionally, 4,486 MBoe 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

With respect to the properties included in our prior year reserve reports, we incurred development costs of $31.1 million in 2016 as compared to $39.8 million in 2015. The year over year change in developmental costs is also reflective of our operated drilling focus in 2016 to preserve term leasehold acreage in the Permian Basin. With respect to the total proved value, 2 gross (1.7 net) horizontal proved undeveloped drilling locations are scheduled to be drilled after some corresponding portion of primary term leasehold within each is set to expire. The Company plans to drill two alternative non-proven locations that will convert the leasehold to held-by-production status prior to any lease expiration. Without consideration of continuous drilling operations and lease conversion activity, total proved reserves would be adversely affected by 2.2% on a volumetric basis and 0.4% on a value basis.

At December 31, 2016, no proved undeveloped reserves have remained, or are scheduled to remain, undeveloped beyond five years from its corresponding initial booking date.

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Changes in Proved Reserves

Proved reserves reported by us at December 31, 2016, increased from those reported at December 31, 2015, as follows:

	Oil Equivalent (MBoe)
Proved reserves as of December 31, 2015	33,120
Production	(5,182)
Extensions, discoveries and other additions	34,543
Purchases of minerals in place	3,323
Sales of minerals in place	—
Revisions of previous estimates	(5,537)
Proved reserves as of December 31, 2016	60,267
Proved developed reserves:	
As of December 31, 2016	37,656
Proved undeveloped reserves:	
As of December 31, 2016	22,611

Extensions, discoveries and other additions to proved reserves were the result of drilling wells in the Permian Basin and new compression and well deepening projects in Aneth Field.

The Permian Basin 2016 drilling program resulted in total additions of 14,762 net MBoe of proved developed producing reserves, which included 13,855 net MBoe from the successful drilling of non-proved locations and 907 net MBoe from the acquisition of additional interests in these wells during 2016. These successful wells also created additional proved undeveloped offset locations of 17,957 net MBoe, which included 16,202 net MBoe related to the addition of the 20 immediate offset proved undeveloped Permian location and 1,755 net MBoe related to the acquisition of additional ownership in existing leases. No proved undeveloped locations were developed during 2016.

Additionally, 4,486 MBoe 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.

In accordance with SEC requirements, the oil reserves at December 31, 2016 and 2015, utilized average NYMEX West Texas Intermediate oil prices of $42.75 and $50.28 per Bbl, respectively, for the Aneth Properties and average Plains Marketing, L.P. posted West Texas Intermediate oil prices of $39.25 and $46.79 per Bbl, respectively, for the Permian Basin Properties. For gas, the reserves at December 31, 2016 and 2015, utilized average Platts Gas Daily El Paso San Juan Basin spot gas price of $2.33, $2.46, and $4.31 per MMBtu for the Aneth Properties and Platts Gas Daily El Paso Permian Basin spot gas price of $2.31, $2.45, and $4.25 per MMBtu for the Permian Properties, respectively.

Revisions of previous estimates primarily relate to projects that had economically proved reserves at December 2015 average prices, but were not economically proved reserves at December 2016 average prices.

Controls Over Reserve Report Preparation, Technical Qualification and Methodologies Used

Reserve estimates as of December 31, 2016, were prepared by Resolute and audited by Netherland Sewell and 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 32 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.

NSAI is a worldwide leader of petroleum property analysis to industry and financial organizations and government agencies. With offices in Dallas and Houston, NSAI delivers high quality, fully integrated engineering, operational, geologic, geophysical, petrophysical and economic solutions for all facets of the upstream energy industry. Within NSAI, the technical person primarily responsible for the NSAI audit is Mr. David Miller. Mr. Miller has been practicing consulting petroleum engineering at NSAI since 1997. He is a Registered Professional Engineer in the States of Texas and Louisiana and has more than 35 years of practical experience in petroleum engineering, with more than nineteen years of experience in the estimation and evaluation of reserves. He graduated from the University of Kentucky in 1981 with a Bachelor of Science degree in Civil Engineering and from Southern Methodist University in 1994 with a Master of Business Administration degree. Mr. Miller's qualifications meet or exceed the education, training, and experience requirements set forth in the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers. 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, 2016, 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 2016, 2015 and 2014.

	Year Ended December 31,		
	2016	2015	2014
Sales Data:			
Oil (MBbl)	3,821	3,271	3,488
Gas (MMcf)	4,811	5,194	5,023
NGL (MBbl)	559	400	320
Combined volumes (MBoe)	5,182	4,536	4,645
Daily combined volumes (Boe per day)	14,157	12,427	12,727
Average Realized Prices (excluding derivative settlements):			
Oil ($/Bbl)	$38.83	$42.16	$84.28
Gas ($/Mcf)	2.22	2.43	5.23
NGL ($/Bbl)	9.80	10.32	28.58
Average Production Costs ($/Boe):			
Lease operating expense	$12.29	$17.50	$24.26
Production and ad valorem taxes	3.14	4.41	8.01

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In each of the years presented above, total estimated proved reserves attributed to our Delaware Basin Project area and Aneth Field exceeded fifteen percent of our total proved reserves expressed on an equivalent basis. Therefore, the tables below summarize our operating data for the Delaware Basin Project area and Aneth Field for 2016, 2015 and 2014.

Delaware Basin Project area:

	Year Ended December 31,		
	2016	2015	2014
Sales Data:			
Oil (MBbl)	1,489	393	209
Gas (MMcf)	3,989	1,579	615
NGL (MBbl)	549	224	90
Combined volumes (MBoe)	2,704	880	401
Daily combined volumes (Boe per day)	7,387	2,412	1,099
Average Realized Prices (excluding derivative settlements):			
Oil ($/Bbl)	$42.25	$43.50	$75.51
Gas ($/Mcf)	2.40	2.29	4.20
NGL ($/Bbl)	9.64	7.89	22.32
Average Production Costs ($/Boe):			
Lease operating expense	$4.62	$7.47	$14.63
Production and ad valorem taxes	2.14	2.67	3.92

Aneth Field:

	Year Ended December 31,		
	2016	2015	2014
Sales Data:			
Oil (MBbl)	2,132	2,172	2,249
Gas (MMcf)	739	717	276
NGL (MBbl)	—	—	—
Combined volumes (MBoe)	2,255	2,292	2,295
Daily combined volumes (Boe per day)	6,161	6,279	6,287
Average Realized Prices (excluding derivative settlements):			
Oil ($/Bbl)	$36.37	$40.81	$84.76
Gas ($/Mcf)	1.31	1.87	4.76
NGL ($/Bbl)	—	—	—
Average Production Costs ($/Boe):			
Lease operating expense	$20.24	$21.55	$27.08
Production and ad valorem taxes	4.31	5.98	11.04

Oil and Gas Wells

The following table sets forth information as of December 31, 2016, 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. In addition to the wells below, we had interests in and operated 326 gross (206 net) active water and CO_2 injection wells as of December 31, 2016.

	Productive Wells[(1)]	
	Gross	Net
Oil	466	319
Gas	1	—
Total	467	319

1) We operated 458 gross (318 net) productive wells at December 31, 2016.

Drilling Activity

The following table sets forth information with respect to exploration, development and extension wells we completed during 2016, 2015 and 2014. The number of gross wells is the total number of wells we participated in, regardless of our ownership interest in the wells. Fluid injection wells for waterflood and other enhanced recovery projects are not included as gross or net wells.

	Year Ended December 31,		
	2016	2015	2014
Gross exploration wells:			
Productive [(1)]	—	—	1
Dry [(2)]	—	—	—
Total exploration wells	—	—	1
Gross development wells:			
Productive [(1)]	—	1	8
Dry [(2)]	—	—	—
Total development wells	—	1	8
Gross extension wells:			
Productive [(1)(3)]	14	5	11
Dry [(2)]	—	—	—
Total extension wells	14	5	11
Total gross wells drilled	14	6	20

	Year Ended December 31,		
	2016	2015	2014

Net exploration wells:			
Productive [1]	—	—	—
Dry [2]	—	—	—
Total exploration wells	—	—	—
Net development wells:			
Productive [1]	—	1	4
Dry [2]	—	—	—
Total development wells	—	1	4
Net extension wells:			
Productive [1][3]	12	2	6
Dry [2]	—	—	—
Total extension wells	12	2	6
Total net wells drilled	12	3	10

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) Included in the 2015 count is 1 gross (0.1 net) productive extension well sold to Qstar, LLC effective March, 1, 2015, closed May 1, 2015.

Acreage

All of our leasehold acreage is categorized as developed or undeveloped. The following table sets forth information as of December 31, 2016, relating to our leasehold acreage.

	Developed Acreage (1)	
Area	Gross (2)	Net (3)
Aneth Field (UT)	43,218	27,157
Permian Basin (TX)	15,393	12,703
Permian Basin (NM)	3,920	3,582
Wyoming	1,357	1,357
North Dakota	516	99
Total	64,404	44,898

	Undeveloped Acreage (4)	
Area	Gross (2)	Net (3)
Aneth Field (UT)	1,173	1,173
Permian Basin (TX)	4,564	3,681
Wyoming	2,196	2,196
Total	7,933	7,050

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 4,400 net acres (which includes 2,700 net acres of developed and undeveloped Wyoming acreage), 1,000 net acres and 1,000 net acres of undeveloped acreage will revert or expire in 2017, 2018 and 2019, respectively, absent activity to develop such acreage.

Present Activities

As of December 31, 2016, we were in the process of drilling 1 gross (1.0 net) well and there was 1 gross (1.0 net) well waiting on completion operations. Please read “Business and Properties – Descriptions of Properties” for additional discussion regarding our present activities.

Relationship with the Navajo Nation

The purchase of our Aneth Field Properties was facilitated by our strategic alliance with NNOGC and, through NNOGC, the Navajo Nation. The Navajo Nation formed NNOGC, a wholly-owned corporate entity, under Section 17 of the Indian Reorganization Act. We supply NNOGC with acquisition, operational and financial expertise and NNOGC helps us communicate and interact with the Navajo Nation agencies.

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Our strategic alliance with NNOGC is embodied in a Cooperative Agreement consummated with NNOGC and our predecessor company in 2004 to facilitate our joint acquisition of the Chevron Properties. The agreement was amended subsequently to facilitate the joint acquisition of the ExxonMobil Properties and was amended again in conjunction with the sale of 10% of our interest in Aneth Field to NNOGC. That transaction was closed and paid for in two equal installments, each for 5%, in July 2012 and January 2013, each with an effective date of January 1, 2012. Among other things, this agreement provides that:

- We and NNOGC will cooperate on the acquisition and subsequent development of our respective properties in Aneth Field.
- NNOGC will assist us in dealing with the Navajo Nation and its various agencies, and we will assist NNOGC in expanding its financial expertise and operating capabilities. Since acquisition of the Aneth Field Properties, NNOGC has helped facilitate interaction between the Company and the Navajo Nation Minerals Department and other agencies of the Navajo Nation.
- NNOGC has a right of first negotiation in the event of a sale by Resolute of all or substantially all of its Chevron or ExxonMobil Properties. This right is separate from and in addition to the statutory preferential purchase right held by the Navajo Nation. This right of first negotiation has been waived with respect to any transaction consummated prior to December 31, 2017 involving the Aneth Field assets.

In addition to these provisions, NNOGC was granted three separate but substantially similar purchase options. Each purchase option entitled NNOGC to purchase from us up to 10% of the undivided working interests that we acquired from Chevron or ExxonMobil, as applicable, as to each unit in the Aneth Field Properties (each a “Purchase Option”). The Cooperative Agreement amendment executed in 2012 provides for the cancellation of the second Purchase Option and stipulates that NNOGC has one remaining Purchase Option (as it stood prior to the current option exercise and excluding the interest acquired from Denbury and certain other minority interests). The remaining Purchase Option is exercisable until July 2017 at the fair market value of such interest. The exercise by NNOGC of its Purchase Option in full would not give it the right to remove us as operator of any of the Aneth Field Properties.

Marketing and Customers

Crude Oil Sales

Aneth Field. We currently sell all of our oil from our Aneth Field Properties to Western under a purchase agreement dated July 2014. On December 31, 2014, the Company entered into an amendment to the purchase agreement with Western which provides for Resolute to receive a price equal to the NYMEX oil price minus a differential of $8.00 per barrel of oil. The amendment also extended the term of the agreement until March 31, 2015 and provided that the term would continue thereafter on a month-to-month basis until terminated by a party with ninety days prior notice. On December 8, 2015, the Company entered into a second amendment to the agreement which provided for a reduction of the differential to $7.50 per barrel of oil. On May 9, 2016, the Company entered into a third amendment to the agreement which provides that Resolute and NNOGC will receive a price equal to NYMEX oil price minus a differential of $7.50 per barrel of oil for the first 6,000 barrels of oil purchased per day and a differential of $5.50 for amounts in excess of 6,000 barrels per day, with such pricing effective on May 1, 2016. In 2016, Western entered into a pre-merger agreement with Tesoro Corporation. Upon closing of this agreement, we do not anticipate that our business relationship will be negatively impacted; however, we cannot provide assurance of such conclusion. If, for any reason, Western is unable to process our oil, there is alternative access to markets through rail and truck facilities or through the FERC-regulated Texas-New Mexico pipeline owned by Western. Furthermore, oil can be trucked to refineries or oil pipelines in southern New Mexico, west Texas or Salt Lake City, Utah.

Western refines our oil at their 25,000 barrel per day refinery in Gallup, New Mexico. Our production is transported to the refinery via the Running Horse oil pipeline owned by NNOGC to its Bisti terminal, approximately 20 miles south of Farmington, New Mexico. From there, crude is transported through a Western pipeline that serves the refinery. Our and NNOGC’s oil has been jointly marketed to Western. The combined Resolute and NNOGC volumes were approximately 8,900 barrels of oil per day as of year-end. When combined with the royalty barrels owned by the

Navajo Nation, Aneth Field provides approximately 10,300 barrels per day to the Gallup refinery, more than 40% of total refinery capacity.

The Aneth Field oil is a sweet, light crude oil that is well suited to be refined in Western's refinery. Although we have sold all of our oil production to Western since acquiring the Chevron Properties in November 2004, and despite the value of our oil production to Western, we cannot be certain that the commercial relationship with Western will continue for the indefinite future and that the refinery will not suffer significant down-time or be closed. If for any reason Western is unable or unwilling to purchase our oil production, we have other production marketing alternatives. We have the ability to load up to 3,000 barrels per day at Western's Gallup refinery rail loading site in the event that Western is unable to process or otherwise does not take our oil volumes. NNOGC has completed construction of a high volume truck loading facility located at the terminal end of NNOGC's Running Horse pipeline that is capable of loading all of our and NNOGC's production. We have life-of-lease access to the truck loading facility pursuant to an agreement with NNOGC. Oil can be trucked a relatively short distance from the loading facility to rail loading sites near and south of Gallup, New Mexico, or longer distances to refineries or oil pipelines in southern New Mexico, west Texas, or Salt Lake City, Utah, where structural changes in the regional oil supply have created a long term premium market for oil sales to the refineries there and have positioned Salt Lake City as a potentially attractive alternative market for Aneth Field crude oil sales. We can also transport our oil by various combinations of truck and rail from the Aneth Field Properties to markets throughout the United States. The cost of selling our oil to alternative markets in the short term may result in a greater differential to the NYMEX price of oil than we currently receive. If we choose or are forced to sell to these alternative markets for a longer period of time, these costs could be lowered significantly. Under long term arrangements, which may require the investment of capital, we believe we would realize a NYMEX differential approximately equal to the current differential realized in the price received from Western.

Other fields. With respect to our oil production from all other fields, we generally sell our crude oil under 30-day contracts at the best available price in the area, the most significant purchasers of which were Western Refining Southwest Inc, Plains Marketing LP, and Holly Frontier LLC for 2016.

Gas and NGL Sales

Our gas and NGL are sold to various midstream processing companies under long-term percent of proceeds contracts, including Castleton Commodities International, LLC in the Aneth Field, Energy Transfer Partners, L.P. in the Delaware Basin Project area, and West Texas Gas and DCP Midstream in the Northwest Shelf Project area.

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."

Aneth Gas Processing Plant

We have an interest in gas gathering and compression facilities located within and adjacent to our Aneth Field Properties. Collectively called the Aneth Gas Processing Plant, the facility consists of: a) an active gas compression operation currently operated by us and b) a substantially dismantled gas processing facility for which Chevron remains the operator of record. In 2006, Chevron began the process of demolishing the inactive portions of the Aneth Gas Processing Plant. It continues to manage the project, and it retains a 39% interest in all demolition and environmental clean-up expenses. We acquired ExxonMobil's 25% interest in the decommissioned plant and an additional 6.5% interest through another acquisition and are responsible for that total of approximately 31.5% of decommissioning and cleanup costs. Activities performed to date include removal of asbestos-containing building and insulation materials, nearly complete dismantling of inactive gas plant buildings and facilities and limited remediation of hydrocarbon-affected soil.

As of December 31, 2016, we estimate the total cost to fully decommission the inactive portion of the Aneth Gas Processing Plant site to be $26.3 million, of which approximately $25.8 million had already been incurred and paid for. These costs do not include any costs for clean-up or remediation of the subsurface, nor for minor additional demolition and removal activity associated with buried piping and concrete foundations. In February 2016 Chevron notified the working interest owners of its intent to renew certain rights-of-way with the Navajo Nation in anticipation of renewed clean-up activity at the site. Chevron has budgeted approximately $0.4 million for right-of-way renewal and site assessment studies associated with possible asbestos contamination of soil at the site. Resolute's share of this cost is approximately $0.1 million. The Aneth Gas Processing Plant site was previously evaluated by the Environmental Protection Agency ("EPA") for possible listing on the National Priorities List ("NPL"), of sites contaminated with hazardous substances with the highest priority for clean-up under the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"). Based on its investigation, the EPA concluded no further investigation was warranted and that the site was not required to be listed on the NPL. The Navajo Nation Environmental Protection Agency ("Navajo Nation EPA") now has primary jurisdiction over the Aneth Gas Processing Plant site. We cannot predict whether Navajo Nation EPA will require further investigation and possible clean-up, and the ultimate clean-up liability may be affected by the Navajo Nation's recent enactment of a Navajo CERCLA statute. The Navajo CERCLA statute, in some cases, imposes broader obligations and liabilities than the federal CERCLA statute. We have been advised by Chevron that a significant portion of the subsurface clean-up or remediation costs, if any, would be covered by an indemnity agreement from the prior owner of the plant, and Chevron has provided us with a copy of the pertinent purchase agreement that appears to support its position. We cannot predict, however, whether any subsurface remediation will be required or what the cost of this clean-up or remediation could be. Additionally, we cannot be certain whether any of such costs will be reimbursable to us pursuant to the indemnity of the prior owner or whether the prior owner will be able to satisfy their indemnity obligations. Please read "Business and Properties — Environmental, Health and Safety Matters and Regulation — Waste Handling."

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.

In connection with our acquisition of the Chevron and ExxonMobil Properties, we obtained attorneys' title opinions showing good and defensible title in the seller to at least 80% of the proved reserves of the acquired properties as shown in the relevant reserve reports presented by the sellers. We also reviewed land files and public and private records on substantially all of the acquired properties containing proved reserves. Additionally, we reviewed 98% of the title opinions and public records related to the proved reserves in Lea County, New Mexico.

The Aneth Field Properties are subject to a statutory preferential purchase right for the benefit of the Navajo Nation to purchase at the offered price any Navajo Nation oil and gas lease or working interest in such a lease at the time a proposal is made to transfer the lease or interest. This could make it more difficult to sell our oil and gas leases and, therefore, could reduce the value of the Aneth Field leases if we attempt to sell them.

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, tribal, 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 or unpermitted releases may occur, however, 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 or unpermitted releases, 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 tribal and 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 tribal or state laws that are modeled after CERCLA. In the course of our operations, we generate waste that may fall within CERCLA's definition of hazardous substances, as well as under the Navajo Nation CERCLA which, unlike the federal CERCLA, broadly defines "hazardous substances" to include oil and other hydrocarbons, thereby subjecting us to potential liability under the Navajo Nation CERCLA. Therefore, governmental

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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 tribal and 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, that may be regulated as hazardous wastes under RCRA and tribal and state laws and regulations.

We have an interest in the Aneth Gas Processing Plant located in the Aneth Unit. This gas plant consists of a non-operational portion of the plant that has been substantially dismantled by Chevron, and an operational portion dedicated to compression. We are responsible for a portion of the costs of decommissioning, removal and clean-up of the non-operational portion of the plant and any restoration and other costs related to the operational processing facilities. For additional information concerning our obligations related to this plant, please read “Business and Properties — Aneth Gas Processing Plant.”

Air Emissions. The federal Clean Air Act and comparable tribal and 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, tribal 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, tribal and state laws and regulations.

In June 2005, the EPA and ExxonMobil entered into a consent decree settling various alleged violations of the federal Clean Air Act associated with ExxonMobil’s prior operation of the McElmo Creek Unit. In response, ExxonMobil submitted amended Title V and Prevention of Significant Deterioration (“PSD”) permit applications for the McElmo Creek Unit main flare and other sources, and also paid a civil penalty and costs associated with a Supplemental Environmental Project, or “SEP.” Pursuant to the consent decree, ExxonMobil completed upgrades to the main flare in May 2006, and we have met all of the remaining material compliance measures of the consent decree. The EPA is processing the Title V application required by consent decree, and a final PSD permit was issued in the fourth quarter of 2016. We remain subject to the consent decree, including stipulated penalties for violations of emissions limits and compliance measures set forth in the consent decree. We believe the consent decree may be terminated in 2017 by the EPA, although the EPA has given us no definite confirmation, and such termination may not be possible until a final Title V permit is issued.

On July 1, 2011, the EPA promulgated final rules titled “Review of New Sources and Modifications in Indian Country” (Tribal Minor NSR Rules) 76 Fed. Reg. 38748-808 (July 1, 2011). These rules became effective on August 30, 2011 and were subsequently amended, and establish the phased implementation of a program of minor source permitting by the EPA in Indian Country over a period of 48 months. Under the Tribal Minor NSR Rules, new wells and associated equipment located in “Indian Country” that are minor sources even without emission controls did not need to obtain a permit prior to their construction for up to 48 months from the effective date of the rules, August 30, 2015 (although they needed to register with the EPA in most instances), while such sources that exceed major source thresholds without legally and practically enforceable emission control requirements in place must obtain a synthetic minor permit prior to their construction. The Tribal Minor NSR Rules specifically provide for a synthetic minor permit to be issued to an otherwise major source that takes permit restrictions, enforceable as a legal and practical matter, so that the source's potential to emit is less than the minimum amount set for major sources, i.e., 250 tons per year of criteria pollutants in so-called attainment areas. We have evaluated our existing and planned new sources in Indian Country for purposes of registering them, applying for permits as appropriate and evaluating the need to apply for any synthetic minor permits for existing facilities that may undergo modifications. Delays in obtaining such new permits from the EPA under the Tribal Minor NSR Rules could adversely affect our planned activities which previously were not subject to minor source permitting requirements or associated delays and expense.

On August 16, 2012, the EPA published final rules that established new air emission controls 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. On December 31, 2014, the EPA issued still further final revisions in response to stakeholder petitions for reconsideration of various regulatory provisions. Some of these final revisions are also now the subject of petitions for still further administrative reconsideration, specifically including petitions regarding the applicability of new source performance standards to tanks operated in parallel. 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, 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 without being offset by increased product capture. 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.

Actual air emissions reported for our facilities are in material compliance with the terms of existing air permits and the emission limits contained in the pending permit applications and the consent decree when emissions associated with qualified equipment malfunctions are taken into account.

Water Discharges. The federal Water Pollution Control Act, or the Clean Water Act, and analogous tribal and 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, tribal 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 tribal and 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. This report supported the final rule issued in June 2015 that clarifies the scope of the agencies' jurisdiction under section 404 of the CWA to regulate certain activities occurring in Waters of the United States. This rule, known as the Clean Water Rule, has been challenged by various parties in multiple federal courts, and as a result of this litigation is currently stayed and not yet effective.

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, 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.

In November 2001, the EPA issued an administrative order to ExxonMobil for removal and remediation of oil and hydrocarbon contaminated ground water released as a result of a shallow casing leak at the McElmo Creek P-20 well that occurred in January 2001. In response, ExxonMobil performed various site assessment activities and began recovering oil from the ground water. We were obligated to complete the remedial activities required under the administrative order issued to ExxonMobil, at an estimated cost of approximately $25,000 per year. Onsite activities were concluded and a transition to passive monitoring was implemented in 2014 with final closure anticipated in 2017.

Underground Injection Control. Our underground injection operations are subject to the federal Safe Drinking Water Act, as well as analogous tribal and state laws and regulations. Under Part C of the Safe Drinking Water Act, the EPA established the Underground Injection Control program, which established the minimum program requirements for tribal and state programs regulating underground injection activities. The Underground Injection Control program includes requirements for permitting, testing, monitoring, recordkeeping and reporting of injection well activities, as well as a prohibition against the migration of fluid containing any contaminant into underground sources of drinking water. Federal, tribal and state regulations require us to obtain a permit from applicable regulatory agencies to operate our underground injection wells. We believe we have obtained the necessary permits from these agencies for our underground injection wells and that we are in substantial compliance with permit conditions and applicable federal, tribal and state rules. Nevertheless, these regulatory agencies have the general authority to suspend or modify one or more of these permits if continued operation of one of the underground injection wells is likely to result in pollution of freshwater, the substantial violation of permit conditions or applicable rules, or leaks to the environment. Although we monitor the injection process of our wells, any leakage from the subsurface portions of the injection wells could cause degradation of fresh groundwater resources, potentially resulting in cancellation of operations of a well, issuance of fines and penalties from governmental agencies, incurrence of expenditures for remediation of the affected resource and imposition of liability by third parties for property damages and personal injuries. In 2009 and 2010, the EPA evaluated wellbores of producer and injector wells in Aneth Field and suggested that certain wells may not be adequately cased and / or cemented across the bottom of the underground source of drinking water. As a result, the Navajo EPA has required Resolute to perform remedial casing and cement work on selected wellbores concurrent with any significant well work on injection wells. In most cases, remedial work is limited to the affected injection well that is being worked over. In the case of drilling new injection wells or deepening of existing injection wells, the remedial action requirements could potentially impact identified deficient wellbores (producer or injector) within one-half mile of the well being drilled or deepened. Resolute estimates the cost to perform remedial activities, if and when required, could range from $0.1 million to over $0.3 million per deficient well.

Pipeline Integrity, Safety, and Maintenance. Our ownership interest in the McElmo Creek Pipeline has caused us to be subject to regulation by the federal Department of Transportation, or the DOT, under the Hazardous Liquid Pipeline Safety Act and comparable state statutes, which relate to the design, installation, testing, construction, operation, replacement and management of hazardous liquid pipeline facilities. Any entity that owns or operates such pipeline facilities must comply with such regulations, permit access to and copying of records, and file reports and provide required information. The DOT may assess fines and penalties for violations of these and other requirements imposed by its regulations. We believe we are in material compliance with all regulations imposed by the DOT pursuant to the Hazardous Liquid Pipeline Safety Act. Pursuant to the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006, the DOT was required to issue new regulations by December 31, 2007, setting forth specific integrity management program requirements applicable to low stress hazardous liquid pipelines. We believe that such regulations, which have yet to be issued, will not have a material adverse effect on our financial condition or results of operations.

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. All of our current exploration and production activities, as well as proposed exploration and development plans 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 emissions of gases commonly referred to as “greenhouse gases” or “GHG”, including CO_2, nitrogen dioxide and methane, may be contributing to warming of the Earth’s atmosphere. Other nations already have agreed to regulate emissions of GHG 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 GHG 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 yearly intervals starting in 2020. In response to such studies and international action, the U.S. Congress has considered but not yet passed legislation to reduce emissions of GHG. Also, as a result of the U.S. Supreme Court’s decision on April 2, 2007, in Massachusetts. v. EPA, the EPA may be required to regulate GHG emissions from mobile sources (e.g., cars and trucks) even if Congress does not adopt new legislation specifically addressing GHG emissions. The Court’s holding in Massachusetts v. EPA that GHG fall under the federal Clean Air Act’s definition of “air pollutant” has 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 inject CO_2 for enhanced oil recovery and geologic sequestration, regardless of the magnitude of associated CO_2 emissions, and also to operators of oil and gas systems 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, the Aneth Field is the only asset operated by the Company that is 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, 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, the new final rules in NSPS Subparts 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. In addition, the federal Bureau of Land Management (BLM) has proposed 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 also 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, it has also set an expedited briefing schedule for hearing the plaintiffs' arguments on the merits for overturning parts of the BLM rule, and a decision is expected in the Spring/Summer of 2017. The EPA and BLM actions are part of a series of steps by the Obama Administration that are 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 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 greenhouse gas emissions. Such cases may seek to challenge air emissions permits that greenhouse gas 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.

In November 2016, the EPA also issued a final Information Collection Request (ICR) to the oil and gas industry to support development of new regulations covering methane emissions at existing oil and gas sites. There will be both an "operator survey" and a "facility survey" response due in 2017, with greater detail required in the "facility survey". This process could result in additional regulations on existing oil and gas sites potentially leading to increased operating and compliance costs.

Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases 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 20, 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, tribal, 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 tribal and state health and safety requirements.

Laws and Regulations Pertaining to Oil and Gas Operations on Navajo Nation Lands

General. Laws and regulations pertaining to oil and gas operations on Navajo Nation lands derive from both Navajo law and federal law, including federal statutes, regulations and court decisions, generally referred to as federal Indian law.

The Federal Trust Responsibility. The federal government has a general trust responsibility to Indian tribes regarding lands and resources that are held in trust for such tribes. The trust responsibility may be a consideration in courts’ resolution of disputes regarding Indian trust lands and development of oil and gas resources on Indian reservations. Courts may consider the compliance of the Secretary of the U.S. Department of the Interior, or the Interior Secretary, with trust duties in determining whether leases, rights-of-way or contracts relative to tribal land are valid and enforceable.

Tribal Sovereignty and Dependent Status. The U.S. Constitution vests in Congress the power to regulate the affairs of Indian tribes. Indian tribes hold a sovereign status that allows them to manage their internal affairs, subject to the ultimate legislative power of Congress. Tribes are therefore often described as domestic dependent nations, retaining all attributes of sovereignty that have not been taken away by Congress. Retained sovereignty includes the authority and power to enact laws and safeguard the health and welfare of the tribe and its members and the ability to regulate commerce on the reservation. In many instances, tribes have the inherent power to levy taxes and have been delegated authority by the United States to administer certain federal health, welfare and environmental programs.

Because of their sovereign status, Indian tribes also enjoy sovereign immunity from suit and may not be sued in their own courts or in any other court absent Congressional abrogation or a valid tribal waiver of such immunity. The

United States Supreme Court has ruled that for an Indian tribe to waive its sovereign immunity from suit, such waiver must be clear, explicit and unambiguous.

NNOGC is a federally chartered corporation incorporated under Section 17 of the Indian Reorganization Act and is wholly owned by the Navajo Nation. Section 17 corporations generally have broad powers to sue and be sued. Courts will review and construe the charter of a Section 17 corporation to determine whether the tribe has either universally waived the corporation's sovereign immunity, or has delegated that power to the Section 17 corporation.

The NNOGC federal charter of incorporation provides that NNOGC shares in the immunities of the Navajo Nation, but empowers NNOGC to waive such immunities in accordance with processes identified in the charter. NNOGC has contractually waived its sovereign immunity, and certain other immunities and rights it may have regarding disputes with us relating to certain of the Aneth Field Properties, in the manner specified in its charter. Although the NNOGC waivers are similar to waivers that courts have upheld, if challenged, only a court of competent jurisdiction may make that determination based on the facts and circumstances of a case in controversy.

Tribal sovereignty also means that in some cases a tribal court is the only court that has jurisdiction to adjudicate a dispute involving a tribe, tribal lands or resources or business conducted on tribal lands or with tribes. Although language similar to that used in our agreements with NNOGC that provide for alternative dispute resolution and federal or state court jurisdiction has been upheld in other cases, there is no guarantee that a court would enforce these dispute resolution provisions in a future case.

Federal Approvals of Certain Transactions Regarding Tribal Lands. Under current federal law, the Interior Secretary (or the Interior Secretary's appropriate designee) must approve any contract with an Indian tribe that encumbers, or could encumber, for a period of seven years or more, (1) lands owned in trust by the United States for the benefit of an Indian tribe or (2) tribal lands that are subject to a federal restriction against alienation, or collectively "Tribal Lands." Failure to obtain such approval, when required, renders the contract void.

Except for our oil and gas leases, rights-of-way and operating agreements with the Navajo Nation, our agreements do not by their terms specifically encumber Tribal Lands, and we believe that no Interior Secretarial approval was required to enter into those agreements. With respect to our oil and gas leases and unit operating agreements, these and all assignments to us have been approved by the Interior Secretary. In the case of rights-of-way and assignments of these to us, some of these have been approved by the Interior Secretary and others are in various stages of applications for renewal and approval. It is common for these approvals to take an extended period of time, but such approvals are routine and we believe that all required approvals will be obtained in due course.

Federal Management and Oversight. Reflecting the federal trust relationship with tribes, the Bureau of Indian Affairs, or the BIA, exercises oversight of matters on the Navajo Nation reservation pertaining to health, welfare and trust assets of the Navajo Nation. Of relevance to us, the BIA must approve all leases, rights-of-way, applications for permits to drill, seismic permits, CO_2 pipeline permits and other permits and agreements relating to development of oil and gas resources held in trust for the Navajo Nation. While NNOGC has been successful in facilitating timely approvals from the BIA, such timeliness is not guaranteed and obtaining such approvals may cause delays in developing the Aneth Field Properties.

Resources and Development Committee of the Navajo Nation Council. The Resources and Development Committee (the "Resources Committee") is a standing committee of the Navajo Nation Tribal Council, and has oversight and regulatory authority over all lands and resources of the Navajo Nation. The Resources Committee reviews, negotiates and recommends to the Navajo Nation Tribal Council actions involving the approval of energy development agreements and mineral agreements; gives final approvals of rights of way, surface easements, geophysical permits, geological prospecting permits, and other surface rights for infrastructure; oversees and regulates all activities within the Navajo Nation involving natural resources and surface disturbance; sets policy for natural resource development and oversees the enforcement of federal and Navajo law in the development and utilization of resources, including issuing cease and desist orders and assessing fines for violation of its regulations and orders. The Resources Committee also has oversight authority over, among other agencies and matters, the Navajo Nation Environmental Protection Agency and Navajo Nation environmental laws, the Navajo Nation Minerals Department and Navajo Nation oil and gas laws and the Navajo Nation Land Department and Navajo Nation land use laws. While we have been successful thus far in obtaining timely approvals from the Resources Committee for our operations, such timeliness is not guaranteed and obtaining future approvals may cause delays in developing the Aneth Field Properties.

Navajo Nation Minerals Department of the Division of Natural Resources. The day-to-day operation of the Navajo Nation minerals program, including the initial negotiation of agreements, applications for approval of assignments, exercise of tribal preferential rights and most other permits and licenses relating to oil and gas development, is managed by the professional staff of the Navajo Nation Minerals Department, located within the Division of Natural

Resources and subject to the oversight of the Resources Committee. The Resources Committee and the Navajo Nation Council typically defer to the Minerals Department in decisions to approve all leases and other agreements relating to oil and gas resources held in trust for the Navajo Nation.

Taxation by the Navajo Nation. In certain instances, federal, state and tribal taxes may be applicable to the same event or transaction, such as severance taxes. State taxes are rarely applicable within the Navajo Nation Reservation except as authorized by Congress or when the application of such taxes does not adversely affect the interests of the Navajo Nation. Federal taxes of general application are applicable within the Navajo Nation, unless specifically exempted by federal law. We currently pay the following taxes to the Navajo Nation:

- Oil and Gas Severance Tax. We pay severance tax to the Navajo Nation. The severance tax is payable monthly and is 4% of our gross proceeds from the sale of oil and gas. Approximately 84% of the Aneth Unit is subject to the Navajo Nation severance tax. The other 16% of the Aneth Unit is exempt because it is either located off of the reservation or it is incremental enhanced oil recovery production, which is not subject to the severance tax. Presently all of the McElmo Creek and Ratherford Units are subject to the severance tax.
- Possessory Interest Tax. We pay a possessory interest tax to the Navajo Nation. The possessory interest tax applies to all property rights under a lease within the Navajo Nation boundaries, including natural resources.
- Sales Tax. We pay the Navajo Nation a 5% sales tax in lieu of the Navajo Business Activity Tax. All goods and services purchased for use on the Navajo Nation reservation are subject to the sales tax. The sale of oil and gas is exempt from the sales tax.

Royalties from Production on Navajo Nation Lands. Under our agreements and leases with the Navajo Nation, we pay royalties to the Navajo Nation. The Navajo Nation is entitled to take its royalties in kind, which it currently does for its oil royalties. The Minerals Management Service of the United States Department of the Interior has the responsibility for managing and overseeing royalty payments to the Navajo Nation as well as the right to audit royalty payments.

Navajo Preference in Employment Act. The Navajo Nation has enacted the Navajo Preference in Employment Act, or the Employment Act, requiring preferential hiring of Navajos by non-governmental employers operating within the boundaries of the Navajo Nation. The Employment Act requires that any Navajo candidate meeting job description requirements receives a preference in hiring. The Employment Act also provides that Navajo employees can only be terminated, penalized, or disciplined for “just cause,” requires a written affirmative action plan that must be filed with the Navajo Nation, establishes the Navajo Labor Commission as a forum to resolve employment disputes and provides authority for the Navajo Labor Commission to establish wage rates on construction projects. The restrictions imposed by the Employment Act and its recent broad interpretations by the Navajo Supreme Court may limit our pool of qualified candidates for employment.

Navajo Business Opportunity Act. Navajo Nation law requires companies doing business in the Navajo Nation to provide preference priorities to certified Navajo-owned businesses by giving them a first opportunity and contracting preference for all contracts within the Navajo Nation. While this law does not apply to the granting of mineral leases, subleases, permits, licenses and transactions governed by other applicable Navajo and federal law, we treat this law as applicable to our material non-mineral contracts and procurement relating to our general business activities within the Navajo Nation.

Navajo Environmental Laws. The Navajo Nation has enacted various environmental laws that may be applicable to our Aneth Field Properties. As a practical matter, these laws are patterned after similar federal laws, and the Navajo EPA currently enforces these laws in conjunction with the EPA. The current practice does not preclude the Navajo Nation from taking a more active role in enforcement or from changing direction in the future. Some of the Navajo Nation environmental laws not only provide for civil, criminal and administrative penalties, but also provide for third-party suits brought by Navajo Nation tribal members directly against an alleged violator, with specified jurisdiction in the Navajo Nation District Court in Window Rock. An example of this relates to the March 2008 adoption by the Navajo Nation of the Navajo Comprehensive Environmental Response, Compensation, and Liability Act (“Navajo CERCLA”), which gives the Navajo EPA broad authority over environmental assessment and remediation of facilities contaminated with hazardous substances. Navajo CERCLA is patterned after federal CERCLA with the important exception that, unlike federal CERCLA, Navajo CERCLA considers oil and other hydrocarbons to be hazardous substances subject to CERCLA response actions and damages. Navajo CERCLA also imposes a tariff on the transportation of hazardous substances, including petroleum and petroleum products, across Navajo lands. In 2008, we began negotiating with representatives of the Navajo Nation Council, Navajo Department of Justice, Navajo Environmental Protection Agency, NNOGC, an industry group headed by the New Mexico Oil and Gas Association and Colorado Oil and Gas Association, ("the NMOGA Group"), and others, to mitigate Navajo CERCLA's potential impact on oilfield operations on Navajo lands. The NMOGA Group challenged the validity of the law and entered into a tolling agreement with the Navajo EPA (which was subsequently amended several times) that forestalled material implementation of Navajo CERCLA at oil and gas facilities while appropriate rules and guidelines are developed with input from the oil and gas sector. A partial settlement agreement was entered into in January 2012 among the NMOGA Group parties and the Navajo Nation. Under the terms of this agreement, enforcement of most of the material provisions of Navajo CERCLA is delayed for at least five years and the NMOGA Group retains its ability to file suit to challenge the law at such five-year period. Although the five year period has passed since entering into this agreement, Navajo Nation has not taken any steps to enforce Navajo CERCLA. In the interim, the Navajo Nation EPA has indicated it will require routine reporting of spills of oil and other hazardous substances to now go directly to the Navajo CERCLA program personnel within the Navajo Nation EPA, in addition to that information going to other spill reporting contacts within the Navajo Nation EPA.

Thirty-Two Point Agreement. An explosion at an ExxonMobil facility in Aneth Field in December 1997 prompted protests by local tribal members and temporary shutdown of the field. The protesters asserted concerns about environmental degradation, health problems, employment opportunities and renegotiating leases. The protest was settled among the local residents, ExxonMobil and the Navajo Nation by the Thirty-Two Point Agreement that provided, among other things, for ExxonMobil to pay partial salaries for two Navajo public liaison specialists, follow Navajo hiring practices, and settle further issues addressed in the Thirty-Two Point Agreement in the Navajo Nation's "peacemaker" courts, which follow a community-level conflict resolution format. After the Thirty-Two Point Agreement was executed, Aneth Field resumed normal operations. While we did not formally assume the obligations of ExxonMobil under the Thirty-Two Point Agreement when we acquired the ExxonMobil Properties in 2006, it has been our policy to voluntarily comply with this agreement. While we believe that our relations with the Navajo Nation are satisfactory, it is possible that employee relations or community relations degrade to a point where protests and shutdown occur in the future.

Moratorium on Future Oil and Gas Development Agreements and Exploration. In February 1994, the Navajo Nation issued a moratorium on future oil and gas development agreements and exploration on lands situated within the Aneth Chapter on the Navajo Reservation. All of the Aneth Unit and a significant portion of the McElmo Creek Unit are located within the Aneth Chapter. The Navajo Nation has recently taken the position that the term of the moratorium is indefinite. Given that our operations within the Aneth Chapter are based on existing agreements and that we currently do not contemplate new exploration in this mature field, the moratorium has had and is expected to continue to have minor impact to our operations.