EVOLUTION PETROLEUM CORP
Form 10-K
September 10, 2018
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K
ý ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended June 30, 2018
o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission File Number 001-32942
EVOLUTION PETROLEUM CORPORATION
(Exact name of registrant as specified in its charter)

| | |
|---|---|
| Nevada | 41-1781991 |
| (State or other jurisdiction of incorporation or organization) | (IRS Employer Identification No.) |

1155 Dairy Ashford Road, Suite 425, Houston, Texas 77079
(Address of principal executive offices and zip code)
(713) 935-0122
(Registrant's telephone number, including area code)
Securities registered pursuant to Section 12(b) of the Act:

| Title of Each Class | Name of Each Exchange On Which Registered |
|---|---|
| Common Stock, $0.001 par value | NYSE American |
| 8.5% Series A Cumulative Preferred Stock, $0.001 par value | NYSE American |

Securities registered pursuant to Section 12(g) of the Act:
None
(Title of Class)
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes: o No: ý
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes: o No: ý
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: ý No: o
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: ý No: o
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

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

| | | |
|---|---|---|
| Large accelerated filer o | | Accelerated filer ý |
| Non-accelerated filer o | (Do not check if a smaller reporting company) | Smaller reporting company o |
| Emerging growth company o | | |

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act.). Yes: o No: ý

The aggregate market value of the voting and non-voting common equity held by non-affiliates on December 31, 2017, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price on that date of $6.85 on the NYSE American was $127,161,941.

The number of shares outstanding of the registrant's common stock, par value $0.001, as of September 4, 2018, was 33,171,514.

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DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement related to the registrant's 2018 Annual Meeting of Stockholders to be filed within 120 days of the end of the fiscal year covered by this report are incorporated by reference into Part III of this report.

EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES
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This Form 10-K and the information referenced herein contain forward-looking statements within the meaning of the Private Securities Litigations Reform Act of 1995, Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. The words "plan," "expect," "project," "estimate," "assume," "believe," "anticipate," "intend," "budget," "forecast," "predict" and other similar expressions are intended to identify forward-looking statements. These statements appear in a number of places and include statements regarding our plans, beliefs or current expectations, including the plans, beliefs and expectations of our officers and directors. When considering any forward-looking statement, you should keep in mind the risk factors that could cause our actual results to differ materially from those contained in any forward-looking statement. Important factors that could cause actual results to differ materially from those in the forward-looking statements herein include the timing and extent of changes in commodity prices for oil and natural gas, operating risks and other risk factors as described in this Annual Report on Form 10-K as filed with the Securities and Exchange Commission ("SEC"). Furthermore, the assumptions that support our forward-looking statements are based upon information that is currently available and is subject to change. We specifically disclaim all responsibility to publicly update any information contained in a forward-looking statement or any forward-looking statement in its entirety and therefore disclaim any resulting liability for potentially related damages. All forward-looking statements attributable to Evolution Petroleum Corporation are expressly qualified in their entirety by this cautionary statement.

We use the terms, "EPM," "Company," "we," "us" and "our" to refer to Evolution Petroleum Corporation, and unless the context otherwise requires, its wholly-owned subsidiaries.

# PART I

## Item 1. Business

Note: See Glossary of Selected Petroleum Industry Terms at the back of this document - refer to Table of Contents

### General

Evolution Petroleum Corporation is an oil and gas company focused on delivering a sustainable dividend yield to its shareholders through the ownership, management and development of producing oil and gas properties. The Company's long-term goal is to build a diversified portfolio of oil and gas assets primarily through acquisition, while seeking opportunities to maintain and increase production through selective development, production enhancement and other exploitation efforts on its properties. Our largest active investment is our interest in a $CO_2$ enhanced oil recovery project in Louisiana's Delhi field.

Our operations began in September 2003. In May 2004, our predecessor, Natural Gas Systems, Inc., merged into a wholly-owned subsidiary of Reality Interactive, Inc., an inactive public company, which was renamed Natural Gas Systems, Inc. ("NGS"). In connection with the listing of NGS shares on the American Stock Exchange (currently the NYSE American) in July 2006, NGS was renamed Evolution Petroleum Corporation. Our principal executive offices are located at 1155 Dairy Ashford Road, Suite 425, Houston, Texas 77079, and our telephone number is (713) 935-0122. We maintain a website at www.evolutionpetroleum.com, but information contained on our website does not constitute part of this document. Our common stock is traded on the NYSE American under the ticker symbol "EPM".

At June 30, 2018, we had four full-time employees, not including contract personnel and outsourced service providers. None of the Company's employees are currently represented by a union, and the Company believes that it has excellent relations with its employees. Our team is broadly experienced in oil and gas operations, development, acquisitions and financing. We follow a strategy of outsourcing most of our property accounting, human resources, administrative and other non-core functions. As a result of the retirement of Randy Keys, President and Chief Executive Officer on May 31, 2018, the Board of Directors immediately moved to name Robert Herlin to act as Interim Chief Executive Officer and to commence a search for a permanent Chief Executive Officer. Additionally, the Board of Directors created a temporary Transition Services Committee, consisting solely of Director William Dozier, to aid and assist management in primarily evaluating potential property acquisitions and operational matters. Both of these appointments are deemed temporary while the ongoing search for a permanent Chief Executive Officer is resolved.

### Business Strategy

Evolution Petroleum Corporation is an oil and gas company focused on delivering a sustainable dividend yield to its shareholders through the ownership, management and development of producing oil and gas properties. The Company's long-term goal is to build a diversified portfolio of oil and gas assets primarily through acquisition, while seeking opportunities to maintain and increase production through selective development, production enhancement and other exploitation efforts on its properties. Our largest current asset is our interest in a $CO_2$ enhanced oil recovery project in Louisiana's Delhi field.

### Delhi Field - Enhanced Oil Recovery - Onshore Louisiana

Our working and royalty interests in the Delhi Holt-Bryant Unit in the Delhi field (the "Unit"), located in Northeast Louisiana, are currently our sole producing assets. The Unit is approximately 13,636 acres in size and has had a prolific production history totaling approximately 195 million bbls of oil through primary and limited secondary recovery operations since its discovery in the mid-1940s. At the time of our purchase of the field in 2003, the Unit had minimal production. We conveyed our working interest in the field to a subsidiary of Denbury Resources, Inc. in May 2006 for $50 million for the purpose of installing an enhanced oil recovery ("EOR") project in the field. We retained a 23.9% reversionary working interest

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upon payout of the project, as defined in the purchase and sale agreements. Since EOR production began in March 2010, the Unit has produced over 17 million bbls of oil.

We own two types of interests in the Unit:

- 7.2% of overriding royalty interests that are in effect for the life of the Unit and mineral royalty interests, free of all operating and capital cost burdens; and
- A 23.9% working interest with an associated 19.0% net revenue interest. The working interest reverted to us effective November 1, 2014. Upon the occurrence of this contractual payout, we began bearing 23.9% of all operating expenses and capital expenditures.
- The above interests are separate and give us a combined net revenue interest of 26.2%.

Our independent reservoir engineers, DeGolyer & MacNaughton, assigned the following estimated reserves net to our interests at Delhi as of June 30, 2018. Equivalent oil reserves are defined as six MCF of gas and 42 gallons of natural gas liquids to one barrel of oil conversion ratio.

- 9.4 million bbls of proved oil equivalent reserves, with a Standardized Measure of Discounted Future Net Cash Flows ("Standardized Measure") of $119 million, and PV-10* of $146 million
- 4.5 million bbls of probable** oil equivalent reserves
- 4.6 million bbls of possible** oil equivalent reserves

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* PV-10 of Proved reserves is a non-GAAP measure, reconciled to the Standardized Measure at "Estimated Oil and Natural Gas Reserves and Estimated Future Net Revenues" under Item 2. Properties of this Form 10-K. Both the Standardized Measure and PV-10 are based on the average first day of the month net commodity prices received at the Delhi field in the twelve months ending June 30, 2018, which were $57.50 per barrel of oil and $38.97 per barrel of natural gas liquids ("NGL"). Probable and possible reserves are not recognized under GAAP nor is there a comparable GAAP measure for probable and possible reserves.

** With respect to the above reserve numbers, and references to Probable and Possible reserves throughout this document, estimates of Probable and Possible reserves are inherently imprecise. When producing an estimate of the amount of oil and natural gas that is recoverable from a particular reservoir, Probable reserves are those additional reserves that are less certain to be recovered than Proved reserves and there must be at least a 50% probability that the actual quantities recovered will equal or exceed the Proved plus Probable reserve estimates. Possible reserves are even less certain and there must be at least a 10% probability that the actual quantities recovered will equal or exceed the sum of Proved, Probable and Possible reserve estimates. All categories of reserves are continually subject to revisions based on production history, results of additional exploration and development, price changes and other factors. Estimates of Probable and Possible reserves are by their nature much more speculative than estimates of Proved reserves and are subject to greater uncertainties, and accordingly the likelihood of recovering those reserves is subject to substantially greater risk. These three reserve categories have not been adjusted to different levels of recovery risk among these categories and are therefore not comparable and are not meaningfully combined.

The operator originally planned six primary phases for the installation of the CO2 flood in the Delhi field. Four of these phases have been completed as of June 30, 2017 and two remain undeveloped. One of the remaining two phases (Phase V) is reflected as proved undeveloped in our current reserves report and the other was removed from proved reserves (Phase VI) as it was not deemed economic under current pricing guidelines for SEC purposes.

Phase I began CO2 injection in November 2009. First oil production response occurred in March 2010 and production in the field increased to approximately 1,000 gross barrels of oil per day by December 2010.

Implementation of Phase II, which was more than double the size of Phase I, commenced with incremental CO2 injection at the end of December 2010. First oil production response from Phase II occurred during March 2011, and field gross production increased to more than 4,000 barrels of oil per day by June 2011.

Phase III was installed during calendar 2011, and was expanded twice during calendar 2011. Production subsequently increased to more than 5,000 gross barrels of oil per day.

Phase IV was substantially installed during the first six months of calendar 2012. During early calendar 2013, the operator intensified development in the previously redeveloped western side of the field based on production results and new geological mapping that included the results of seismic data acquired over the last few years. Gross field production increased to more than 7,500 gross barrels of oil per day.

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In June 2013, following a fluid release event that consisted of the uncontrolled release of CO2, water, natural gas and a small amount of oil from a previously plugged well in the southwest part of the field, the operator temporarily suspended CO2 injection in most of the southwestern tip of the field. The operator has fully remediated the affected area, but has isolated that part of the field with a water curtain, thus removing that area from the $CO_2$ flood.
This fluid release event, along with other contractual disputes, caused the Company to file suit against the operator in December 2013. In June 2016, we reached a settlement with the operator as described in Note 21 – Delhi Field Litigation Settlement.
Subsequent to the reversion of our working interest to us in November 2014, the operator initiated work on the Phase V expansion of the CO2 flood in the undeveloped eastern part of the field. This project is sometimes referred to as Test Site 5. These operations were suspended shortly after reversion when the operator made significant cuts in its capital budget as a result of declining oil prices. Resumption of this work has been electively delayed due to prevailing oil prices and the partners' allocation of capital to other Delhi projects, primarily the large investment in the NGL plant discussed below. It was further electively delayed based on the conclusion that the economics of the project would be improved if it were implemented after completion of the NGL plant, which has now occurred. We believe that the Phase V expansion of the CO2 flood has favorable economics, particularly in the current oil price environment, and we expect this project to expand the CO2 flood to resume within the next year.
In February 2015, we began construction of an NGL recovery plant in the Delhi Field, which was completed and operational in December 2016. Our net cost for the NGL plant totaled $27 million, which included $0.3 million in September 2017 for capital upgrades to the inlet of recycle plant to bring output capacity up to its expected level.
The NGL plant extracts methane and NGL's from the CO2 recycle stream. The methane and part of the ethane produced by the NGL plant are used to generate electrical power in the field. The extracted NGL's are sold at the field to a purchaser who transports them by truck to a plant for further processing. In addition to the value of these hydrocarbon products, the increased purity of the CO2 stream re-injected into the field should result in operational benefits to the CO2 flood.
In March 2018, the operator began a planned twelve-well infill drilling program in the Delhi field. This program, which has an expected net cost to the Company of approximately $4.7 million, targets productive oil zones in the developed areas of the field that are not being swept effectively by the current $CO_2$ flood. This infill program is expected to both add production and increase ultimate recoveries above the current proved producing oil reserves. Evolution's forecast for the remaining net cost to the Company for this project is approximately $1.9 million.
In conjunction with the infill drilling program, the operator plans to drill the last two wells of a six-well water injection program on the eastern edge of the planned Phase V expansion of the Delhi field. The Company expects all of these projects to be completed by the end of calendar year 2018. In addition to the planned capital spending discussed above, the Company continues to identify and execute successful capital workover projects to improve conformance and production in the field. These projects are not individually material and are unlikely to have a significant impact on capital spending going forward. The operator has further identified other areas in the Delhi field for potential expansion of the $CO_2$ flood, but the Company has not yet quantified any reserves with respect to such areas.
Artificial Lift Technology (GARP®)
We previously owned artificial lift technology registered as GARP® (Gas Assisted Rod Pump) that was developed internally by our former Senior Vice President of Operations. Its design is intended to increase production and extend the life of horizontal and vertical wells with gas, oil or associated water production with the expectation of recovering additional reserves at an economically attractive cost per BOE. We received a patent on our GARP® technology on August 30, 2011, which provides U.S. patent protection for the technology through early 2028. We have further filed for a continuation in part to our patent for recent improvements in the technology, including a concentric design which allows the technology to work in narrower diameter casing.
Subsequent to receiving our patent, we entered into demonstration joint venture projects and commercialization projects with industry operators between 2012 and early 2015. Most of these projects were successful in establishing or restoring commercial rates of production. However, with the severe decline in oil prices that began in late 2014, a

significant portion of these projects were not sufficiently profitable to justify continuation.

As a result of the declining commodity price environment and reduced capital spending by the industry overall, the timing for commercial success of this technology was slower than previously anticipated. Based on a strategic review of these operations, we undertook the separation and transfer of these operations to a new entity controlled by the inventor of the technology and certain former employees of the Company, effective December 31, 2015. We invested $108,750 in common and preferred stock and retained a minority interest in the new entity, Well Lift Inc., together with a 5% royalty on all future gross

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revenues derived from the technology. We have the option to convert our preferred stock investment in Well Lift Inc, into a larger, non-controlling equity stake in the new entity. Consequently, we have retained upside for our shareholders from the potential future commercial success of the technology, while eliminating approximately $1.0 million of annual overhead expenses. We have also retained the right to use the technology in our current wells and any future wells we develop or acquire.

Other Projects

Mississippi Lime—Kay County, Oklahoma

In 2012, we acquired a 45% interest in a joint venture with Orion Exploration, a private company based in Tulsa, Oklahoma. The joint venture was operated by Orion and engaged in the horizontal development of the Mississippi Lime reservoir in Kay County, Oklahoma. Our leasehold position, totaling approximately 6,600 acres, was located in the eastern, more oil-prone side of the play. We drilled one gross salt water disposal well and reached total depth on two horizontally drilled wells in the Mississippi Lime formation. While both wells produced at the fluid rates expected, the quantities of oil and gas were far less than expected. We subsequently reworked both wells to test the role of structure in production, and determined that this play is a structural play requiring substantial geophysical and geological work and expertise in order to be successful, as opposed to a resource play in which engineering is the primary requirement. Accordingly, we elected in fiscal 2013 to reduce our joint venture interest in undeveloped leases to 33.9%, resulting in a $1.2 million reduction in both our net property and accounts payable. In October 2014, we completed the sale of all of our leasehold interests and wells and any associated assets and abandonment liabilities in the Mississippi Lime reservoir to the operator.

Markets and Customers

We market our production to third parties in a manner consistent with industry practices. In the U.S. market where we operate, crude oil and natural gas liquids are readily transportable and marketable. We do not currently market our share of crude oil production from Delhi separately from the operator's share of production. Although we have the right to take our working interest production in-kind, we are currently selling our oil under the Delhi operator's agreement with Plains Marketing L.P. pursuant to the delivery and pricing terms thereunder. The oil from Delhi is currently transported from the field by pipeline, which results in better net pricing than the alternative of transportation by truck. Delhi crude oil production sells at Louisiana Light Sweet ("LLS") pricing which generally trades at a premium to West Texas Intermediate ("WTI") crude oil pricing. The positive LLS Gulf Coast average price differential over WTI, as quoted daily on the New York Mercantile Exchange ("NYMEX"), was approximately $3.82 per barrel during our fiscal year ended June 30, 2018. The differential has increased from the prior year and we expect that a positive LLS price differential will continue, at least in the near future. Our overall average net oil price, including the LLS premium and after all adjustments for transportation, marketing and other price differentials, was $0.30 per barrel more than the average WTI NYMEX price for fiscal 2018.

Upon completion of the NGL plant in late 2016, we began selling natural gas liquids from the Delhi field to American Midstream Gas Solutions, L.P. Title to these products is transferred to the purchaser at the field and they are transported by truck to the purchaser's processing facility. We receive market prices, less transportation, processing and quality differential fees for the net yield of the individual natural gas liquid components, consisting of propane, butanes, and C5+ (pentanes and heavier components). There is a small component of residual ethane, but the overall yield of products is a higher value mix than is typical for natural gas liquids.

The following table sets forth purchasers of our oil and natural gas production for the years indicated:

| | Year Ended June 30, | | |
|---|---|---|---|
| Customer | 2018 | 2017 | 2016 |
| Plains Marketing L.P. (Oil sales from Delhi) | 92 % | 97 % | 99 % |
| American Midstream Gas Solutions (NGL sales from Delhi) | 8 % | 3 % | — % |
| All others | — % | — % | 1 % |
| Total | 100% | 100% | 100% |

The loss of our purchaser at the Delhi field or disruption to pipeline transportation from the field could adversely affect our net realized pricing and potentially our near-term production levels. The loss of any of our other purchasers would not be expected to have a material adverse effect on our operations.

Market Conditions

Marketing of crude oil, natural gas, and natural gas liquids and the prices we receive are influenced by many factors that are beyond our control, the exact effect of which is difficult to predict. These factors include changes in supply and demand, market prices, government regulation and actions of major foreign producers.

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Over the past 30 years, crude oil price fluctuations have been extremely volatile, with crude oil prices varying from less than \$10 to over \$140 per barrel. More recently, the price of oil per barrel dropped dramatically, starting in the fourth quarter of 2014 and continuing into 2017 before recovering somewhat in 2018. Worldwide factors such as geopolitical, macroeconomic, supply and demand, refining capacity, petrochemical production and derivatives trading, among others, influence prices for crude oil. Local factors also influence prices for crude oil and include increasing or decreasing production trends, quality differences, regulation and transportation issues unique to certain producing regions and reservoirs.

Also over the past 30 years, domestic natural gas prices have been extremely volatile, ranging from \$1 to \$15 per MMBTU. The spot market for natural gas, changes in supply and demand, derivatives trading, pipeline availability, BTU content of the natural gas and weather patterns, among others, cause natural gas prices to be subject to significant fluctuations. Due to the practical difficulties in transporting natural gas, local and regional factors tend to influence product prices more for natural gas than for crude oil.

Competition

The oil and natural gas industry is highly competitive for prospects, acreage and capital. Our competitors include major integrated crude oil and natural gas companies and numerous independent crude oil and natural gas companies, individuals and drilling and income programs. Many of our competitors are large, well-established companies with substantially larger operating staffs and greater capital resources than ours. Competitors are national, regional or local in scope and compete on the basis of financial resources, technical prowess or local knowledge. The principal competitive factors in our industry are expertise in given geographical and geological areas and the abilities to efficiently conduct operations, achieve technological advantages, identify, acquire economically producible reserves and obtain capital at rates which allow economic investments.

Seasonality

For a discussion of seasonal changes that affect our business, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Other Economic Factors - Seasonality in this Form 10-K.

Government Regulation

Numerous federal and state laws and regulations govern the oil and gas industry. These laws and regulations are often changed in response to changes in the political or economic environment. Compliance with this evolving regulatory burden is often difficult and costly, and substantial penalties may be incurred for noncompliance. To the best of our knowledge, we are in compliance with all laws and regulations applicable to our operations and we believe that continued compliance with existing requirements will not have a material adverse impact on us. The future annual capital cost of complying with the regulations applicable to our operations is uncertain and will be governed by several factors, including future changes to regulatory requirements which are unpredictable. However, we do not currently anticipate that future compliance with existing laws and regulations will have a materially adverse effect on our consolidated financial position or results of operations.

See "Government regulation and liability for environmental matters that may adversely affect our business and results of operations" under Item 1A. Risk Factors of this Form 10-K, for additional information regarding government regulation.

Insurance

We maintain insurance on our operated and non-operated properties and operations for risks and in amounts customary in the industry. Such insurance includes general liability, excess liability, control of well, operators extra expense, casualty, fraud and directors & officer's liability coverage. Not all losses are insured, and we retain certain risks of loss through deductibles, limits and self-retentions. We do not carry lost profits coverage and we do not have coverage for consequential damages.

Additional Information

We file Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other reports with the Securities and Exchange Commission ("SEC") . Our reports filed with the SEC are available free of charge to the general public through our website at www.evolutionpetroleum.com. These reports are accessible on our website as soon as reasonably practicable after being filed with, or furnished to, the SEC. This Annual Report on Form 10-K and our other filings can also be obtained by contacting: Corporate Secretary, 1155 Dairy Ashford Road, Suite 425, Houston, Texas 77079, or calling (713) 935-0122. These reports are also available at the SEC Public Reference Room at 450 Fifth Street, N.W., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC also maintains a website at www.sec.gov that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

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## Item 1A. Risk Factors

Our business involves a high degree of risk. If any of the following risks, or any risk described elsewhere in this Annual Report on Form 10-K, actually occurs, our business, financial condition or results of operations could suffer. The risks described below are not the only ones facing us. Additional risks not presently known to us or which we currently consider to be immaterial also may adversely affect us.

### Risks related to the oil and gas industry and our Company

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

The price we receive for our oil significantly influences our revenue, profitability, access to capital and future rate of growth. Oil is a commodity and its price is subject to wide fluctuations in response to relatively minor changes in supply and demand. For example, average daily prices for WTI crude oil ranged from a high of $74 per barrel to a low of $27 per barrel over the past three fiscal years ending June 30, 2018. Historically, the markets for oil and natural gas liquids have been volatile and these markets will likely continue to be volatile in the future. The prices we receive for our production depend on numerous factors beyond our control, including, but not limited to the following:

- worldwide and regional economic conditions impacting the global supply and demand for oil and gas;
- actions of OPEC or other groups of oil producing nations;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions in or affecting other oil-producing and natural gas-producing countries;
- the level of global oil and natural gas exploration and production;
- the level of global oil and natural gas inventories;
- localized supply and demand fundamentals of regional, domestic and international transportation availability;
- weather conditions and natural disasters;
- domestic and foreign governmental regulations;
- speculation as to the future price of oil and the speculative trading of oil and natural gas futures contracts;
- price and availability of competitors' supplies of oil and natural gas;
- technological advances effecting energy consumption; and
- the price and availability of alternative fuels.

Substantially all of our production is sold to purchasers under short-term (less than twelve-month) contracts at market-based prices. A decline in oil and natural gas liquids prices will reduce our cash flows, borrowing ability, the present value of our reserves and our ability to develop future reserves. We may be unable to obtain needed capital or financing on satisfactory terms. Low oil and natural gas liquids prices may also reduce the amount of oil and natural gas liquids that we can produce economically, which could lead to a decline in our oil and natural gas liquids reserves. Because approximately 86% of our proved reserves at June 30, 2018 are crude oil reserves and 14% are natural gas liquids reserves, we are heavily impacted by movements in crude oil prices, which also influence natural gas liquids prices. To the extent that we have not hedged our production with derivative contracts or fixed-price contracts, any significant and extended decline in oil and natural gas liquids prices may adversely affect our financial position.

Our revenues are concentrated in one asset and related declines in production or other events beyond our control could have a material adverse effect on our results of operations and financial results.

Substantially all of our revenues come from our royalty, mineral and working interests in the Delhi field in Louisiana and thus our current revenues are highly concentrated in this field. Any significant downturn in production, oil and gas prices, or other events beyond our control which impact the Delhi field could have a material adverse effect on our results of operations and financial results. We are not the operator of the Delhi field, and our revenues and future growth are heavily dependent on the success of operations, which we do not control.

Operating results from oil and natural gas production may decline; we may be unable to acquire and develop the additional oil and natural gas reserves that are required in order to sustain our business operations.

In general, the volumes of production from crude oil and natural gas properties decline as reserves are depleted, with the rate of decline depending on reservoir characteristics. Except to the extent we acquire additional properties containing proved reserves or conduct successful development activities, or both, our proved reserves will decline.

Our production is heavily dependent on our interests in EOR production that began during March 2010 in the Delhi field. Environmental or operating problems or lack of future investment at Delhi could cause our net production of oil and natural gas liquids to decline significantly over time, which could have a material adverse effect on our financial condition.

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

Substantially all of our property interests are not operated by the Company and also involve other third-party working interest owners. As a result, we have limited ability to influence or control the operation or future development of such properties, including compliance with environmental, safety and other regulations, or the amount of capital expenditures that we will be required to fund with respect to such properties. Operators of these properties may act in ways that are not in our best interest. Moreover, we are dependent on the other working interest owners of such projects to fund their contractual share of the capital expenditures of such projects. These limitations and our dependence on the operator and other working interest owners for these projects could cause us to incur unexpected future costs, result in lower production and materially and adversely affect our financial conditions and results of operations.

We are materially dependent upon our operator with respect to the successful operation of our principal asset, which consists of our interests the Delhi field. A materially negative change in our operator's financial condition could negatively affect operations (or timing thereof) in the Delhi field, and consequently our income (or timing thereof) from the field as well as the value of our interests in the Delhi field.

Our royalty, mineral and working interests in the Delhi field, located in Northeast Louisiana, currently represent our sole producing asset. Over 99% of our revenues come from these interests and thus our current revenues are highly concentrated in this field. Any significant downturn in production or other events beyond our control which impact the Delhi field could have a material adverse effect on our results of operations and financial results (or timing thereof).

We are not the operator of the Delhi field. It is operated by a subsidiary of Denbury Resources Inc. ("DNR"). Our revenues and future growth are thus heavily dependent on the success of operations which we do not control.

Further, our $CO_2$ - Enhanced Oil Recovery ("$CO_2$-EOR") project in the Delhi field requires significant amounts of $CO_2$ reserves and technical expertise, the sources of which have been committed by the operator. Additional capital remains to be invested to fully develop this project, further increase production and maximize the value of this asset. The operator's failure to manage these and other technical, environmental, operating, strategic, financial and logistical matters could cause ultimate enhanced recoveries from the planned $CO_2$ - EOR project to fall short of our expectations in volume and/or timing. Such occurrences could have a material adverse effect on us, and our results of operations and financial condition.

Our economic success is thus materially dependent upon the Delhi field operator's ability to: (i) deliver sufficient quantities of $CO_2$ from its reserves in the Jackson Dome source, (ii) secure its share of capital necessary to fund development and operating commitments with respect to the field and (iii) successfully manage related technical, operating, environmental, strategic and logistical risks, among other things.

We are aware that DNR, which is publicly traded, has disclosed in its public SEC filings certain risks related to its current level of indebtedness and the related financial covenants. They have stated, for example, that their level of indebtedness could have important consequences, including, among others, requiring dedication of a substantial portion of DNR's cash flow from operations to servicing their indebtedness. They noted that their ability to meet their obligations under their debt instruments will depend in part upon prevailing economic conditions and commodity prices. DNR also noted that it has from time to time deferred development spending for certain projects.

Given the current stress in the global commodity markets and oil and gas in particular, our operator could be materially negatively impacted, which could in turn negatively affect the operator's ability to operate the Delhi field as well as its financial commitment to the $CO_2$-EOR project in the field, and thus our interests in the Delhi field could be materially negatively impacted.

The types of resources we focus on have substantial operational risks.

Our business plan focuses on the acquisition and development of known resources in partially depleted reservoirs, naturally fractured or low permeability reservoirs, or relatively shallow reservoirs. Shallower reservoirs usually have lower pressure, which generally translates into lower reserve volumes in place. Low permeability reservoirs require more wells and substantial stimulation for development of commercial production. Naturally fractured reservoirs require penetration of sufficient undepleted fractures to establish commercial production. Depleted reservoirs require successful application of newer technology to unlock incremental reserves.

Our $CO_2$-EOR project in the Delhi field, operated by a subsidiary of Denbury Resources Inc., requires significant amounts of $CO_2$ reserves, development capital and technical expertise, the sources of which to date have been committed by the operator. Although initial $CO_2$ injection began at Delhi in November 2009, initial oil production response began in March 2010 and a large part of the capital budget has already been expended, additional capital remains to be invested to fully develop the EOR project, further increase production and maximize the value of the asset. The operator's failure to manage these and other technical, environmental, operating, strategic, financial and logistical risks may cause ultimate enhanced recoveries from the

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planned $CO_2$-EOR project to fall short of our expectations in volume and/or timing. Such occurrences would have a material adverse effect on the Company, its results of operations and financial condition.

Crude oil and natural gas development, re-completion of wells from one reservoir to another reservoir, restoring wells to production and drilling and completing new wells are speculative activities and involve numerous risks and substantial uncertain costs.

Our growth will be materially dependent upon the success of our future development program. Drilling for crude oil and natural gas and re-working existing wells involve numerous risks, including the risk that no commercially productive crude oil or natural gas reservoirs will be encountered. The cost of drilling, completing and operating wells is substantial and uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors beyond our control, including, but not limited to:

- unexpected drilling conditions;
- pressure fluctuations or irregularities in formations;
- equipment failures or accidents;
- environmental events;
- inability to obtain or maintain leases on economic terms, where applicable;
- adverse weather conditions;
- adverse weather conditions;compliance with governmental requirements; and
- shortages or delays in the availability of drilling rigs or crews and the delivery of equipment.

Drilling or re-working is a highly speculative activity. Even when fully and correctly utilized, modern well completion techniques such as horizontal drilling or $CO_2$ injection or other injectants do not guarantee that we will find and produce crude oil and/or natural gas in our wells in economic quantities. Our future drilling activities may not be successful and, if unsuccessful, such failure would have an adverse effect on our future results of operations and financial condition. We cannot assure you that our overall drilling success rate or our drilling success rate for activities within a particular geographic area will not decline.

We may also identify and develop prospects through a number of methods, some of which do not include horizontal drilling or tertiary injectants, and some of which may be unproven. The drilling and results for these prospects may be particularly uncertain. We cannot assure you that these projects can be successfully developed or that the wells discussed will, if drilled, encounter reservoirs of commercially productive crude oil or natural gas.

The loss of a large single purchaser of our oil and natural gas could reduce the competition of our production.

For the year ended June 30, 2018, one purchaser accounted for 92% of our oil and natural gas liquid revenues. We do not currently market our share of crude oil production from the Delhi field. Although we have the right to take our working interest production in-kind, we are currently accepting terms under the Delhi operator's agreement with Plains Marketing L.P. for the delivery and pricing of our oil at the field. The loss of such large single purchaser for our oil and natural gas production could negatively impact the revenue we receive. We cannot assure you we could readily find other purchasers for our oil and natural gas production. In addition, the crude oil production from the Delhi field is transported by pipeline and if this pipeline transportation were disrupted and we were forced to use alternative transportation methods, our net realized pricing and potentially our near-term production levels could be adversely affected.

Our crude oil and natural gas reserves are only estimates and may prove to be inaccurate.

There are numerous uncertainties inherent in estimating crude oil and natural gas reserves and their estimated values. Our reserves are only estimates that may prove to be inaccurate because of these uncertainties. Reservoir engineering is a subjective and inexact process of estimating underground accumulations of crude oil and natural gas that cannot be measured in an exact manner. Estimates of economically recoverable crude oil and natural gas reserves depend upon a number of variable factors, such as historical production from the area compared with production from other producing areas and assumptions concerning effects of regulations by governmental agencies, future crude oil and natural gas product prices, future operating costs, severance and excise taxes, development costs and work-over and remedial costs. Some or all of these assumptions may vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of crude oil and natural gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery, and estimates of the future net cash flows expected therefrom prepared by different engineers or by the same engineers but at different times, may vary substantially.

Accordingly, reserve estimates may be subject to downward or upward adjustment. Actual production, revenue and expenditures with respect to our reserves will likely vary from estimates, and such variances may be material. The information regarding discounted future net cash flows included in this report should not be considered as the current market value of the

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estimated crude oil and natural gas reserves attributable to our properties. The estimated discounted future net cash flows from proved reserves are based on the 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by factors such as the amount and timing of actual production, supply and demand for crude oil and natural gas, increases or decreases in consumption, and changes in governmental regulations or taxation. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the crude oil and natural gas industry in general. The Standardized Measure and PV-10 do not necessarily correspond to market value.

Regulatory and accounting requirements may require substantial reductions in reporting proven reserves.

We review on a periodic basis the carrying value of our crude oil and natural gas properties under the applicable rules of the various regulatory agencies, including the SEC. Under the full cost method of accounting that we use, the after-tax carrying value of our oil and natural gas properties may not exceed the present value of estimated future net after-tax cash flows from proved reserves, discounted at 10%. Application of this "ceiling" test requires pricing future revenues at the previous 12-month average beginning-of-month price and requires a write down of the carrying value for accounting purposes if the ceiling is exceeded. We may in the future be required to write down the carrying value of our crude oil and natural gas properties when crude oil and natural gas prices are depressed or unusually volatile. Whether we will be required to take such a charge will depend in part on the prices for crude oil and natural gas during the previous period and the effect of reserve additions or revisions and capital expenditures during such period. If a write down is required, it would result in a current charge to our earnings but would not impact our current cash flow from operating activities. A large write-down could adversely affect our compliance with the current financial covenants under our credit facility and could limit our access to future borrowings under that facility or require repayment of any amounts that might be outstanding at the time.

Our derivative activities could result in financial losses or could reduce our income.

To achieve more predictable cash flows and to reduce our exposure to adverse fluctuations in the prices of oil and natural gas liquids, we have, and may in the future, enter into derivative arrangements for a portion of our oil and natural gas liquids production, including costless collars and fixed-price swaps. We have not designated any of our derivative instruments as hedges for accounting purposes and record all derivative instruments on our balance sheet at fair value. Changes in the fair value of our derivative instruments are recognized in earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair value of our derivative instruments. Derivative arrangements also expose us to the risk of financial loss in some circumstances, including, but not limited to, if:

- production is less than the volume covered by the derivative instruments;
- the counterparty to the derivative instrument defaults on its contract obligations; or
- there is a change in the expected differential between the underlying price in the derivative instrument and actual price received.

In addition, some of these types of derivative arrangements limit the benefit we would receive from increases in the prices for oil and natural gas liquids and may expose us to cash margin requirements.

We may have difficulty managing future growth and the related demands on our resources and may have difficulty in achieving future growth.

Although we hope to experience growth through acquisitions and development activity, any such growth may place a significant strain on our financial, technical, operational and administrative resources. Our ability to grow will depend upon a number of factors, including, but not limited to the following:

- our ability to identify and acquire new development or acquisition projects;
- our ability to develop existing properties;
- our ability to continue to retain and attract skilled personnel;
- the results of our development program and acquisition efforts;
- the success of our technologies;

- hydrocarbon prices;
- drilling, completion and equipment prices;
- our ability to successfully integrate new properties;
- our access to capital; and
- the Delhi field operator's ability to: (i) deliver sufficient quantities of $CO_2$ from its reserves in the Jackson Dome, secure all of the development capital necessary to fund its and our cost interests, (ii)

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successfully manage technical, operating, environmental, strategic and logistical development and operating risks, and (iii) maintain its own financial stability, among other things.

We cannot assure you that we will be able to successfully grow or manage any such growth.

Our operations may require significant amounts of capital and additional financing may be necessary in order for us to continue our exploitation activities, including meeting potential future drilling obligations.

Our cash flow from our reserves may not be sufficient to fund our ongoing activities at all times. From time to time, we may require additional financing in order to carry out our oil and gas acquisitions, exploitation and development activities. Certain of our undeveloped leasehold acreage may be subject to leases that will expire unless production is established. If our revenues from our reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect our ability to expend the necessary capital to replace our reserves or to maintain our current production. If our cash flow from operations is not sufficient to satisfy our capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or available to us on favorable terms.

We may be subject to risks in connection with acquisitions because of uncertainties in evaluating recoverable reserves, well performance and potential liabilities, as well as uncertainties in forecasting oil and gas prices and future development, production and marketing costs, and the integration of significant acquisitions may be difficult.

We periodically evaluate acquisitions of reserves, properties, prospects and leaseholds and other strategic transactions that appear to fit within our overall business strategy. The successful acquisition of producing properties requires an assessment of several factors, including, but not limited to:

- recoverable reserves
- future oil and natural gas prices and their appropriate differentials;
- development and operating costs;
- potential for future drilling and production;
- validity of the seller's title to properties, which may be less than expected at closing; and
- potential environmental issues, litigation and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and potential recoverable reserves. Inspections may not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. Moreover, in the event of such an acquisition, there is a risk that we could ultimately be liable for unknown obligations related to acquisitions, which could materially adversely affect our financial condition, results of operations or cash flows.

Significant acquisitions and other strategic transactions may involve other risks, including, but not limited to:

- our lean management team's capacity could be challenged by the demands of evaluating, negotiating and integrating significant acquisitions and strategic transactions in concert with the Company's on going business demands;
- the challenge and cost of integrating acquired operations, information management and other technology systems and business cultures with those of our operations while carrying on our ongoing business;
- difficulty associated with coordinating geographically separate organizations;
- an inability to secure, on acceptable terms, sufficient financing that my be required in connection with expanded operations and unknown liabilities; and
- the challenge of attracting and retaining personnel associated with acquired operations.

The process of integrating assets could cause an interruption of, or loss of momentum in, the activities of our business. Members of our senior management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our business. If our senior management is not able to effectively manage the integration process, or if any significant business activities are interrupted as a result of the integration process, our business could suffer. In addition, even if we successfully integrate the assets acquired in an acquisition, it may not be possible to realize the full benefits we may expect in estimated proved reserves, production volumes, cost savings from operating synergies or other benefits anticipated from an acquisition or realize these benefits within the expected time frame.

Government regulation and liability for environmental matters may adversely affect our business and results of operations.

Crude oil and natural gas operations are subject to extensive federal, state and local government regulations, which may be changed from time to time. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, reports concerning operations, the spacing of wells, unitization and pooling of properties and taxation. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of crude oil and natural gas wells below actual production capacity in order to conserve supplies of crude oil and natural gas. There are federal, state and local laws and regulations primarily relating to protection of human health and the environment applicable to the development, production, handling, storage, transportation and disposal of crude oil and natural gas, by-products thereof, the emission of $CO_2$ or other greenhouse gases, and other substances and materials produced or used in connection with crude oil and natural gas operations. In addition, we may inherit liability for environmental damages, whether actual or not, caused by previous owners of property we purchase or lease or nearby properties. As a result, we may incur substantial liabilities to third parties or governmental entities. We are also subject to changing and extensive tax laws, the effects of which cannot be predicted. The implementation of new, or the modification of existing, laws or regulations could have a material adverse effect on us, such as diminishing the demand for our products through legislative enactment of proposed new penalties, fines and/or taxes on carbon that could have the effect of raising prices to the end user.

Our insurance may not protect us against all of the operating risks to which our business is exposed.

The crude oil and natural gas business involves numerous operating hazards such as well blowouts, mechanical failures, explosions, uncontrollable flows of crude oil, natural gas or well fluids, fires, formations with abnormal pressures, hurricanes, flooding, pollution, releases of toxic gas and other environmental hazards and risks, which can result in (i) damage to or destruction of wells and/or production facilities, (ii) damage to or destruction of formations, (iii) injury to persons, (iv) loss of life, or (v) damage to property, the environment or natural resources. While we carry general liability, control of well, and operator's extra expense coverage typical in our industry, we are not fully insured against all risks incidental to our business. Environmental events similar to that experienced in the Delhi field in June 2013 could defer revenue, increase operating costs and/or increase maintenance and repair capital expenditures.

The loss of key personnel could adversely affect us.

We depend to a large extent on the services of certain key management personnel, including our executive officers, the loss of any of whom could have a material adverse effect on our operations. In particular, our future success is dependent upon the abilities of Robert S. Herlin, our Chairman of the Board and Interim Chief Executive Officer, R. Steven Hicks, our Senior Vice President of Engineering and Business Development, and David Joe, Senior Vice President, Chief Financial Officer and Treasurer, to source, evaluate and close deals, raise capital, and oversee our development activities and operations. Presently, the Company is not a beneficiary of any key man life insurance.

Oil field service and materials' prices may increase, and the availability of such services and materials may be inadequate to meet our needs.

Our business plan to develop or redevelop crude oil and natural gas resources requires third party oilfield service vendors and various material providers, which we do not control. We also rely on third-party carriers for the transportation and distribution of our production. As our production increases, so does our need for such services and materials. Generally, we do not have long-term agreements with our service and materials providers. Accordingly, there is a risk that any of our service providers could discontinue servicing our crude oil and natural gas fields for any reason or we may not be able to source the materials we need. Any delay in locating, establishing relationships, and training our sources could result in production shortages and maintenance problems, with a resulting loss of revenue to us. In addition, if costs for such services and materials increase, it may render certain or all of our projects uneconomic, as compared to the earlier prices we may have assumed when deciding to redevelop newly purchased or existing properties. Further adverse economic outcomes may result from the long lead times often necessary to execute and complete our redevelop plans.

We cannot market the crude oil and natural gas that we produce without the assistance of third parties.

The marketability of the crude oil and natural gas that we produce depends upon the proximity of our reserves to, and the capacity of, facilities and third-party services, including crude oil and natural gas gathering systems, pipelines, trucking or terminal facilities, and processing facilities necessary to make the products marketable for end use. The unavailability or lack of capacity of such services and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. A shut-in or delay or discontinuance could adversely affect our financial condition.

We face strong competition from larger oil and gas companies.

Our competitors include major integrated crude oil and natural gas companies and numerous independent crude oil and natural gas companies, individuals and drilling and income programs. Many of our competitors are large, well-established companies with substantially larger operating staffs and greater capital resources than ours. We may not be able to successfully conduct our operations, evaluate and select suitable properties and consummate transactions in this highly competitive environment. Specifically, these larger competitors may be able to pay more for development projects and productive crude oil and natural gas properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, such companies may be able to expend greater resources on hiring contract service providers, obtaining oilfield equipment and acquiring the existing and changing technologies that we believe are and will be increasingly important to attaining success in our industry.

We have been, and in the future may become, involved in legal proceedings related to our Delhi interest or other properties or operations and, as a result, may incur substantial costs in connection with those proceedings.

From time to time we may be a defendant or plaintiff in various lawsuits. The nature of our operations exposes us to further possible litigation claims in the future. There is risk that any matter in litigation could be decided unfavorably against us regardless of our belief, opinion, and position, which could have a material adverse effect on our financial condition, results of operations, and cash flow. Litigation can be very costly, and the costs associated with defending litigation could also have a material adverse effect on our financial condition. Adverse litigation decisions or rulings may damage our business reputation.

Ownership of our oil, gas and mineral production depends on good title to our property.

Good and clear title to our oil, gas and mineral properties is important to our business. Although title reviews will generally be conducted prior to the purchase of most oil, gas and mineral producing properties or the commencement of drilling wells, such reviews do not assure that an unforeseen defect in the chain of title will not arise to defeat our claim which could result in a reduction or elimination of the revenue received by us from such properties.

Poor general economic, business, or industry conditions may have a material adverse effect on our results of operations, liquidity, and financial condition.

During the last few years, concerns over inflation, energy costs, declining oil and gas prices, geopolitical issues, the availability and cost of credit, the U.S. mortgage market, uncertainties with regard to European sovereign debt, the slowdown in economic growth in large emerging and developing markets, such as China, regional or worldwide increases in tariffs or other trade restrictions, and other issues have contributed to increased economic uncertainty and diminished expectations for the global economy. Concerns about global economic conditions have had a significant adverse impact on domestic and international financial markets and commodity prices. If uncertain or poor economic, business or industry conditions in the United States or abroad remain prolonged, demand for petroleum products could diminish or stagnate, production costs could increase, any of which could impact the price at which we can sell our oil, natural gas, and NGLs, affect our vendors', suppliers' and customers' ability to continue operations, and ultimately adversely impact our results of operations, liquidity, and financial condition.

Risks Associated with Our Stock

Our stock price has been and may continue to be volatile.

Our common stock has relatively low trading volume and the market price has been, and is likely to continue to be, volatile. For example, during the fiscal year ending June 30, 2018, our stock price as traded on the NYSE American ranged from $6.35 to $10.50. The variance in our stock price makes it difficult to forecast with certainty the stock price at which an investor may be able to buy or sell shares of our common stock. The market price for our common stock could be subject to fluctuations as a result of factors that are out of our control, such as:

- actual or anticipated variations in our results of operations;
- naked short selling of our common stock and stock price manipulation;
- changes or fluctuations in the commodity prices of crude oil and natural gas;
- general conditions and trends in the crude oil and natural gas industry;

- redemption demands on institutional funds that hold our stock; and
- general economic, political and market conditions.

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Our executive officers, directors and affiliates may be able to control the election of our directors and all other matters submitted to our stockholders for approval.

As of June 30, 2018 our executive officers and directors, in the aggregate, beneficially owned approximately 2.6 million shares, or approximately 7.9% of our beneficial common stock base. JVL Advisors LLC controlled approximately 3.6 million shares or approximately 10.1% of our outstanding common stock. ArrowMark Colorado Holdings LLC controlled approximately 2.3 million shares, or approximately 6.9% of our outstanding common stock. Advisory Research, Inc. controlled approximately 2.5 million shares, or approximately 7.5% of our outstanding common stock and Blackrock Fund Advisors controlled approximately 2.2 million shares, or approximately 6.5% of our outstanding common stock. As a result, any of these holders could potentially exercise significant influence over matters submitted to our stockholders for approval (including the election and removal of directors and any merger, consolidation or sale of all or substantially all of our assets). This concentration of ownership may have the effect of delaying, deferring or preventing a change in control of our company, impede a merger, consolidation, takeover or other business combination involving our company or discourage a potential acquirer from making a tender offer or otherwise attempting to obtain control of our company, which in turn could have an adverse effect on the market price of our common stock.

The market for our common stock is limited and may not provide adequate liquidity.

Our common stock trades on the NYSE American. Our trading volume decreased in fiscal 2018 compared to fiscal 2017. Trading volume in our common stock is relatively low compared to larger companies. During the fiscal year ended June 30, 2018, the daily trading volume in our common stock ranged from a low of 20,600 shares to a high of 807,500 shares, with average daily trading volume of 112,015 shares compared to average daily volume of 127,419 in fiscal 2017. Our holders may find it more difficult to sell their shares, should they desire to do so, based on the trading volume and price of our stock at that time relative to the quantity of shares to be sold.

If securities or industry analysts do not publish research reports about our business, or if they downgrade our stock, the price of our common stock could decline.

Small, relatively unknown companies can achieve visibility in the trading market through research and reports that industry or securities analysts publish. To our knowledge there are four independent analysts that cover our company. The limited number of published reports by independent securities analysts could limit the interest in our common stock and negatively affect our stock price. We do not have any control over the research and reports these analysts publish or whether they will be published at all. If any analyst who does cover us downgrades our stock, our stock price could decline. If any analyst ceases coverage of our company or fails to regularly publish reports on us, we could lose visibility in the financial markets, which in turn could cause our stock price to decline.

The issuance of additional common stock and preferred stock could dilute existing stockholders.

We currently have in place a registration statement which allows the Company to publicly issue up to $500 million of additional securities, including debt, common stock, preferred stock, and warrants. At any time we may make private offerings of our securities. The shelf registration is intended to provide greater flexibility to the company in financing growth or changing our capital structure. We are authorized to issue up to 100,000,000 shares of common stock. To the extent of such authorization, our board of directors has the ability, without seeking stockholder approval, to issue additional shares of common stock in the future for such consideration as our board may consider sufficient. The issuance of additional common stock in the future would reduce the proportionate ownership and voting power of the common stock now outstanding. We are also authorized to issue up to 5,000,000 shares of preferred stock, the rights and preferences of which may be designated in series by our board of directors. Such designation of any new series of preferred stock may be made without stockholder approval, and could create additional securities which would have dividend and liquidation preferences over the common stock now outstanding. Preferred stockholders could adversely affect the rights of holders of common stock by:

- exercising voting, redemption and conversion rights to the detriment of the holders of common stock;
- receiving preferences over the holders of common stock regarding our surplus funds in the event of our dissolution, liquidation or the payment of dividends to preferred stockholders;
- delaying, deferring or preventing a change in control of our company; and

- discouraging bids for our common stock.

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Continued payment of dividends on our common stock could be impacted.

Our Board of Directors declared cash dividends on our common stock for the first time in December 2013 and we have declared and paid quarterly cash dividends since that time. However, there is no certainty that dividends will be declared by the Board of Directors in the future. Any payment of cash dividends on our common stock in the future will be dependent upon the amount of funds legally available, our earnings, if any, our financial condition and business plan, restrictions contained in current or future debt instruments, contractual covenants or arrangements we may enter into, our anticipated capital requirements and other factors that our board of directors may think are relevant. Accordingly, there is no guarantee that we will be able or choose to continue to pay cash dividends on our common stock.

## Item 1B. Unresolved Staff Comments

None.

## Item 2. Properties

Certain parts of the information required by Item 2. is contained in Item 1. Business

### Oil & Gas Properties

Additional detailed information describing the types of properties we own can be found in "Business Strategy" under Item 1. Business of this Form 10-K.

### Estimated Oil and Natural Gas Reserves and Estimated Future Net Revenues

The SEC sets rules related to reserve estimation and disclosure requirements for oil and natural gas companies. These rules require disclosure of oil and gas proved reserves by significant geographic area, using the trailing 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, rather than year-end prices, and allows the use of new technologies in the determination of proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. Subject to limited exceptions, the rules also require that proved undeveloped reserves may only be classified as such if a development plan has been adopted indicating that they are scheduled to be drilled within five years.

There are numerous uncertainties inherent in estimating quantities of proved reserves and estimates of reserves quantities and values must be viewed as being subject to significant change as more data about the properties becomes available.

Estimates of Probable and Possible reserves are inherently imprecise. When producing an estimate of the amount of oil and natural gas liquids that is recoverable from a particular reservoir, Probable reserves are those additional reserves that are less certain to be recovered than Proved reserves but which, together with Proved reserves, are as likely as not to be recovered, generally described as having a 50% probability of recovery of that amount or more. Possible reserves are even less certain and generally require only a 10% or greater probability of that amount or more being recovered. All categories of reserves are continually subject to revisions based on production history, results of additional exploration and development, price changes and other factors. Estimates of Probable and Possible reserves are by their nature much more speculative than estimates of Proved reserves and are subject to greater uncertainties, and accordingly the likelihood of recovering those reserves is subject to substantially greater risk. These three reserve categories have not been adjusted to different levels of recovery risk among these categories and are therefore not comparable and are not meaningfully combined.

### Information About the Standardized Measure of Discounted Future Net Cash Flows ("Standardized Measure") and pre-tax PV-10 of Proved Reserves

Estimated pre-tax future net revenues from the production of Proved reserves discounted at 10%, or PV-10, is a financial measure that is not recognized by GAAP. We believe that the presentation of the non-GAAP financial measure of PV-10 provides useful information to investors because it is widely used by analysts and investors in evaluating oil and natural gas companies, and that it is relevant and useful for evaluating the relative monetary significance of oil and natural gas properties. Further, analysts and investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies' reserves. We also use this pre-tax measure when assessing the potential return on investment related to oil and natural gas properties and in evaluating acquisition opportunities. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, we believe the use of a pre-tax measure is valuable for evaluating our Company. PV-10 is not a measure of financial or operating performance under GAAP, nor is it intended to represent the current market value of our estimated oil and natural gas reserves. PV-10 should not be considered in isolation or as a substitute for the Standardized Measure as defined under GAAP, and reconciled herein this Item 2. Properties.

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Summary of Oil & Gas Reserves for Fiscal Year Ended 2018

Our proved, probable and possible reserves at June 30, 2018, denominated in equivalent barrels using six MCF of gas and 42 gallons of natural gas liquids to one barrel of oil conversion ratio, were estimated by our independent petroleum engineer, DeGolyer and MacNaughton ("D&M"). D&M was selected to estimate reserves for our interests in the Delhi field due to their expertise in CO2-EOR projects and to ensure consistency with the operator. The scope and results of their procedures are summarized in a letter from the firm, which is included as exhibit 99.1 to this Annual Report on Form 10-K.

The following table sets forth our estimated proved, probable and possible reserves as of June 30, 2018. For additional reserve information see Note 23 – Supplemental Disclosures about Oil and Natural Gas Producing Properties (Unaudited) of the consolidated financial statements. The NYMEX previous 12-month unweighted arithmetic average first-day-of-the-month price used to calculate estimated revenues was $57.50 per barrel of crude oil. The net price per barrel of natural gas liquids was $38.97, which does not have any single comparable reference index price. The NGL price was based on historical prices received. For periods for which no historical price information was available, we used comparable pricing in the area. Pricing differentials were applied based on quality, processing, transportation, location and other pricing aspects for each individual property and product.

Reserves as of June 30, 2018

| Reserve Category | Oil (MBbls) | | NGLs (MBbls) | | Total Reserves (MBOE)* | |
|---|---|---|---|---|---|---|
| PROVED | | | | | | |
| Developed (78% of Proved) | 6,292 | | 994 | | 7,286 | |
| Undeveloped (22% of Proved) | 1,798 | | 284 | | 2,082 | |
| TOTAL PROVED | 8,090 | | 1,278 | | 9,368 | |
| Product Mix | 86 | % | 14 | % | 100 | % |
| PROBABLE | | | | | | |
| Developed (80% of Probable) | 3,123 | | 493 | | 3,616 | |
| Undeveloped (20% of Probable) | 757 | | 120 | | 877 | |
| TOTAL PROBABLE | 3,880 | | 613 | | 4,493 | |
| Product Mix | 86 | % | 14 | % | 100 | % |
| POSSIBLE | | | | | | |
| Developed (88% of Possible) | 3,458 | | 546 | | 4,004 | |
| Undeveloped (12% of Possible) | 488 | | 77 | | 565 | |
| TOTAL POSSIBLE | 3,946 | | 623 | | 4,569 | |
| Product Mix | 86 | % | 14 | % | 100 | % |

*BOE computed on units of production using a six to one conversion ratio of MCF's to barrels.

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The following tables present a reconciliation of changes in our proved, probable and possible reserves by major property, on the basis of equivalent MBOE quantities.

Reconciliation of Changes in Proved Reserves by Major Property

| Proved reserves, MBOE | Delhi Field Proved Total MBOE |
|---|---|
| June 30, 2017 | 10,058.4 |
| Production | (745.3 ) |
| Revisions | 54.9 |
| Sales of minerals in place | — |
| Improved recovery, extensions and discoveries | — |
| June 30, 2018 | 9,368.0 |

Reconciliation of Changes in Probable Reserves by Major Property

| Probable reserves, MBOE | Delhi Field Probable Total MBOE |
|---|---|
| June 30, 2017 | 5,268.0 |
| Revisions | (775.0 ) |
| Sales of minerals in place | — |
| Improved recovery, extensions and discoveries | — |
| June 30, 2018 | 4,493.0 |

Reconciliation of Changes in Possible Reserves by Major Property

| Possible reserves, MBOE | Delhi Field Possible Total MBOE |
|---|---|
| June 30, 2017 | 3,216.2 |
| Revisions | 1,353.3 |
| Sales of minerals in place | — |
| Improved recovery, extensions, and discoveries | — |
| June 30, 2018 | 4,569.5 |

Reconciliation of PV-10 to the Standardized Measure of Discounted Future Net Cash Flows

The following table provides a reconciliation of PV-10 of our proved properties to the Standardized Measure as shown in Note 23 – Supplemental Disclosures about Oil and Natural Gas Producing Properties (Unaudited) of the consolidated financial statements.

| | For the Years Ended June 30, | |
|---|---|---|
| | 2018 | 2017 |
| Estimated future net revenues | $270,842,377 | $189,347,437 |
| 10% annual discount for estimated timing of future cash flows | 124,798,505 | 78,452,886 |
| Estimated future net revenues discounted at 10% (PV-10) | 146,043,872 | 110,894,551 |
| Estimated future income tax expenses discounted at 10% | (27,085,458 ) | (27,956,998 ) |
| Standardized Measure | $118,958,414 | $82,937,553 |

Our sole producing assets as of June 30, 2018 and 2017 were our interests in the Delhi field. Additional information about the properties we own can be found in Item 1. Business.

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Internal Controls Over Reserves Estimation Process and Qualifications of Technical Persons with Oversight for the Company's Overall Reserve Estimation Process

Our policies regarding internal controls over reserves estimates require such estimates to be prepared by an independent engineering firm under the supervision of our Chairman of the Board and interim Chief Executive Officer and Senior Vice President of Engineering and Business Development, a professional petroleum engineer. Such reserves estimates are to be in compliance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC. Our Chairman of the Board and interim Chief Executive Officer holds B.S. and M.E. degrees from Rice University in chemical engineering and earned an M.B.A. from Harvard University. He has over 30 years of experience in engineering, energy transactions, operations and finance with small independents, larger independents and major integrated oil companies. Our Senior Vice President of Engineering and Business Development received Bachelor of Science degree in petroleum engineering from the University of Oklahoma in 1979 and has over 39 years of experience in the energy industry with upstream oil and gas companies. Our outside consultant who assisted the Company in preparing its reserves estimates is a licensed professional engineer with over 30 years of experience in oil and gas operations and petroleum reservoir engineering and holds a Bachelor of Science in Petroleum Engineering from Texas A&M University.

The reserves information in this filing is based on estimates prepared by DeGolyer and MacNaughton, our independent engineering firm. The person responsible for preparing the reserves report with D&M is a Registered Professional Engineer in the State of Texas and a Senior Vice President of the firm. He received a Bachelor of Science degree in petroleum engineering from the University of Texas in 1984, has over 35 years of experience in the energy industry and is a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers. We provide our engineering firm with property interests, production, current operating costs, current production prices and other information. This information is reviewed by our Senior Vice President of Engineering and Business Development and outside consultant to ensure accuracy and completeness of the data prior to submission to our independent engineering firm. The scope and results of our independent engineering firm's procedures, as well as their professional qualifications, are summarized in the letter included as exhibit 99.1 to this Annual Report on Form 10-K.

Proved Undeveloped Reserves

Our proved undeveloped reserves were 2,082 MBOE at June 30, 2018, with associated future development costs of approximately $12.8 million. Our proved undeveloped reserves are comprised of (a) 1,545 MBOE of reserves and $10.9 million of future development costs associated with the Phase V development in the eastern portion of the field and (b) 537 MBOE of reserves and $1.9 million of future development costs associated with a proposed twelve-well infill drilling program to increase production and recover reserves which are not believed to be effectively producible with the existing well configuration. The infill project has aspects of both acceleration of production and an increase in ultimate reserves recovery and is being treated as a proved undeveloped project.

During the year ended June 30, 2018 our proved undeveloped reserves changed as follows:

| | Oil (MBbls) | NGLs (MBbls) | Total Reserves (MBOE) |
|---|---|---|---|
| June 30, 2017 | 1,755 | 353 | 2,108 |
| Revisions to previous estimates | 43 | (69) | (26) |
| Conversion to proved developed reserves | — | — | — |
| June 30, 2018 | 1,798 | 284 | 2,082 |

NGL reserves were revised downward 69 MBOE reflecting lower than originally expected plant production partially offset by 43 MBOE of oil reserves due to better performance.

During fiscal 2018 we spent $2.8 million on development of the twelve-well infill project, which during the year had been expanded from its original eight-well program, and $1.1 million on infrastructure for Test Site 5, or Phase V, primarily for water facilities and water curtain wells and related infrastructure. The twelve-well infill program consists of eight producer wells and four CO2 injection wells. Three producer wells and one CO2 injection well went online at the end of our fourth quarter, and the remaining five producer wells and three CO2 injection wells are expected to be completed and brought online by the end of October 2018.

The initial assignment of proved undeveloped reserves in the Delhi field was made on June 30, 2010, which encompassed a large scale $CO_2$ enhanced oil recovery project. The operator's development plans for the field have remained essentially unchanged and were originally scheduled to be completed by June 30, 2015, within five years from the initial recording of such

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proved reserves. Developed reserves are approximately 78% of total proved reserves as of June 30, 2018. However, as a result of the adverse fluid release event in the field in June 2013 and the resulting delay in reversion of our working interest, development of the field has not proceeded as originally scheduled. Expansion of the CO2 flood to the remaining undeveloped eastern portion of the field commenced subsequent to reversion of our working interest in late calendar 2014. We incurred $3.8 million of capital expenditures before the operator electively deferred this project as a result of a reduction in its cash flows and capital spending from the significant drop in oil prices. This project was further electively deferred as we began work on the NGL recovery plant in the Delhi field in February 2015. It was determined that the economics of development of the remaining eastern portion of the field would be significantly improved after the NGL plant was completed.

During the year ended June 30, 2015, we authorized the NGL plant project and from late in that fiscal year until January 2017 when production of NGL began, we incurred $26.0 million of related capital expenditures. The NGL plant was completed in December 2016 and we converted approximately 1,377 MBOE of proved undeveloped reserves to proved developed reserves during the year ended June 30, 2017.

As of June 30, 2018, we had estimated future net capital expenditures of $10.9 million remaining for development of the eastern part of the field. This work was suspended in late 2014 and further deferred until the NGL recovery plant was complete. We believe this project is economic in the current oil price environment and we expect it to be completed within the next two fiscal years. This would be nine years after the initial recording of proved reserves. During this period, we have been continuously developing the Delhi field and have spent over $35 million subsequent to reversion of our working interest in November 2014. Within the first half of fiscal 2019, we will incur an additional $1.9 million to complete the infill project and an additional $1.7 million of infrastructure for Test Site 5 as described above. Given the long-term nature of CO2 EOR development projects, we believe that the remaining undeveloped reserves in the Delhi field satisfy the conditions to continue to be treated as proved undeveloped reserves because (1) we initially established the development plan for the Delhi field in 2010 and continue to follow that plan, as adjusted to incorporate the completion of the NGL plant in late 2016 and delays relating to the 2013 fluid release event; (2) we have had significant ongoing development activities at this project that, as budgeted and currently being expended, reflect a significant and sufficient portion of remaining capital expenditures to convert proved undeveloped reserves to proved developed reserves; and (3) the operator has a historical record of completing the development of comparable long-term projects.

As of June 30, 2018, no proved, probable or possible reserves were attributed to (a) the suspended southwestern tip area of the field, (b) the area beneath the inhabited portion of the Town of Delhi in the northeast and (c) the farthest east of the two remaining undeveloped sites in the eastern portion of field (Phase VI) due to the current economics and other technical aspects of our future development plans. In addition, no probable reserves are currently attributed to three smaller reservoirs within the Unit in similar formations with similar production history due to the lower oil price utilized in our reserves calculation. We also do not have proved or probable reserves associated with the Mengel Sand, a separate interval within the Unit that is not currently producing, which was received in the litigation settlement in June 2016.

Sales Volumes, Average Sales Prices and Average Production Costs

The following table shows the Company's sales volumes and average sales prices received for crude oil, natural gas liquids, and natural gas for the periods indicated:

| | Year Ended June 30, 2018 | | Year Ended June 30, 2017 | | Year Ended June 30, 2016 | |
|---|---|---|---|---|---|---|
| Product | Volume | Price | Volume | Price | Volume | Price |
| Crude oil (Bbls) | 651,931 | $58.52 | 724,523 | $46.31 | 658,041 | $39.71 |
| Natural gas liquids (Bbls) | 93,366 | $33.50 | 43,907 | $21.28 | 491 | $16.06 |
| Natural gas (Mcf) | — | $— | 16 | $(0.25 ) | 1,620 | $1.79 |
| Average price per BOE* | 745,297 | $55.39 | 768,433 | $44.88 | 658,802 | $39.68 |
| | | | | | | |
| Production costs | Amount | | Amount | | Amount | |

| | | per BOE | | per BOE | | per BOE |
|---|---|---|---|---|---|---|
| Production costs, excluding ad valorem and production taxes | $12,005,444 | $16.11 | $10,621,256 | $13.82 | $8,767,490 | $13.31 |
| Total production costs, including ad valorem and production taxes | $12,193,502 | $16.36 | $10,835,809 | $14.10 | $9,062,179 | $13.76 |

* BOE computed on units of production using a six to one conversion ratio of MCF's to barrels.

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Drilling Activity

Our productive drilling activity during the past three fiscal years ended June 30, 2018, was limited to five (1.2 net) producer wells completed in fiscal 2018. We completed one (.239 net) $CO_2$ injection well during fiscal 2018 and had no completions in the previous two fiscal years. In connection with establishing a water curtain in advance of Phase V site development, we completed one (.239 net) well in fiscal 2018 and one (.239 net) well in fiscal 2017, the initial well of the program. No dry wells were drilled in the past three fiscal years.

Present Activities

As of June 30, 2018, the Company had commenced drilling of one (.239 net) producer well, two (.48 net) $CO_2$ injection wells and two (.48 net) wells in the water curtain program. Additional on-going development activities also include related flowlines and other infrastructure.

For further discussion, see "Highlights for our fiscal year 2018" and "Capital Budget" under Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations of this Form 10-K.

Delivery Commitments

As of June 30, 2018, we were neither committed to provide a fixed and determinable quantity of oil, NGLs or gas under existing agreements, nor do we currently intend to enter into any such agreements.

Productive Wells

The following table sets forth the number of productive oil and gas wells in which we owned a working interest as of June 30, 2018.

| | Company Operated | | Non-Operated | | Total | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| Crude oil | — | — | 102 | 24.3 | 102 | 24.3 |
| Natural gas | — | — | — | — | — | — |
| Total | — | — | 102 | 24.3 | 102 | 24.3 |

Acreage Data

The following table sets forth certain information regarding our developed and undeveloped lease acreage as of June 30, 2018. Developed acreage refers to acreage on which wells have been drilled or completed to a point that would permit production of oil and gas in commercial quantities. Undeveloped acreage refers to acreage on which wells have not been drilled or completed to a point that would permit production of oil and gas in commercial quantities whether or not the acreage contains proved reserves.

| Field | Developed Acreage | | Undeveloped Acreage | | Total | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| Delhi Field, Louisiana* | 9,126 | 2,180 | 4,510 | 1,077 | 13,636 | 3,257 |

When the Company acquired the Delhi field in 2003, the field had been fully developed through primary and secondary recovery and all of such acreage was reflected as developed acreage. With the addition of a CO2-EOR project in the field, certain acreage is now reflected as undeveloped using tertiary recovery operations. We estimate that our developed acreage currently includes 9,126 gross (2,180 net) acres in the Delhi field, with approximately 4,510 gross (1,077 net) acres attributable to the remaining undeveloped areas in the eastern part of the field. We own a 23.9% working interest in the field, along with certain mineral and royalty interests. We are not the operator of the EOR project.

Our interests include all depths from the surface of the earth to the top of the Massive Anhydride, including the Delhi Holt Bryant Unit, which is currently under CO2 flood, and the Mengel Sand Interval, which is within the boundary of the field, but is currently not producing. As the Delhi field is unitized, all acreage, including any undeveloped, nonproductive or undrilled acreage is held by existing production as long as continuous production is maintained in the unit.

* This table excludes acreage attributable to small overriding royalty interests retained in various formations in the Giddings Field area. None of such acreage is currently producing and our interests are subject to expiration if leases

are not maintained by others or commercial production is not established. It does not currently appear likely that we will obtain any significant value from these interests.

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For more complete information regarding current year activities, including crude oil and natural gas production, refer to Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations of this Form 10-K.

## Item 3. Legal Proceedings

See Note 16 – Commitments and Contingencies under Item 8. Financial Statements for a description of legal proceedings, which is incorporated herein by reference.

## Item 4. Mine Safety Disclosures

Not Applicable.

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## PART II

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

Common Stock

Our common stock is currently traded on the NYSE American under the ticker symbol "EPM". The following table shows, for each quarter of the fiscal years ended June 30, 2018 and 2017, the high and low sales prices for EPM as reported by the NYSE American.

NYSE American: EPM

| 2018: | High | Low |
|---|---|---|
| Fourth quarter ended June 30, 2018 | $10.50 | $7.75 |
| Third quarter ended March 31, 2018 | $8.30 | $6.70 |