Matador Resources Co
Form 10-K
March 01, 2019
Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)
ý ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2018
or
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission file number
001-34574
Matador Resources Company
(Exact name of registrant as specified in its charter)

Texas (State or other jurisdiction of incorporation or organization)	27-4662601 (I.R.S. Employer Identification No.)
5400 LBJ Freeway, Suite 1500 Dallas, Texas 75240 (Address of principal executive offices)	75240 (Zip Code)

Registrant's telephone number, including area code: (972) 371-5200

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

Title of each class	Name of each exchange on which registered
Common Stock, par value $0.01 per share	New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes ý No ¨
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes ¨ No 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 ¨
Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ý No ¨

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

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

Large accelerated filer	ý	Accelerated filer	¨
Non-accelerated filer	¨	Smaller reporting company	¨
		Emerging growth company	¨

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

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

The aggregate market value of the voting and non-voting common equity of the registrant held by non-affiliates, computed by reference to the price at which the common equity was last sold, as of the last business day of the registrant's most recently completed second fiscal quarter was $3,305,546,848.

As of February 26, 2019, there were 116,388,317 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

The information required by Part III of this Annual Report on Form 10-K, to the extent not set forth herein, is incorporated by reference to the registrant's definitive proxy statement relating to the 2019 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission within 120 days after the end of the fiscal year to which this Annual Report on Form 10-K relates.

Table of Contents

MATADOR RESOURCES COMPANY
FORM 10-K
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2018
TABLE OF CONTENTS

Table of Contents

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this Annual Report on Form 10-K (this "Annual Report") constitute "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). Additionally, forward-looking statements may be made orally or in press releases, conferences, reports, on our website or otherwise, in the future by us or on our behalf. Such statements are generally identifiable by the terminology used such as "anticipate," "believe," "continue," "could," "estimate," "expect," "forecasted," "hypothetical," "intend," "may," "might," "plan," "potential," "predict," "project," "should, similar words, although not all forward-looking statements contain such identifying words.

By their very nature, forward-looking statements require us to make assumptions that may not materialize or that may not be accurate. Forward-looking statements are subject to known and unknown risks and uncertainties and other factors that may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include, among others: general economic conditions, changes in oil, natural gas and natural gas liquids prices and the demand for oil, natural gas and natural gas liquids, the success of our drilling program, the timing of planned capital expenditures, the sufficiency of our cash flow from operations together with available borrowing capacity under our credit facilities, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as our ability to access them, the proximity to our properties and capacity of transportation facilities, availability of acquisitions, our ability to integrate acquisitions with our business, weather and environmental conditions, uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, and the other factors discussed below and elsewhere in this Annual Report and in other documents that we file with or furnish to the United States Securities and Exchange Commission (the "SEC"), all of which are difficult to predict. Forward-looking statements may include statements about:

- our business strategy;
- our estimated future reserves and the present value thereof;
- our cash flows and liquidity;
- our financial strategy, budget, projections and operating results;
- our oil and natural gas realized prices;
- the timing and amount of future production of oil and natural gas;
- the availability of drilling and production equipment;
- the availability of oil field labor;
- the amount, nature and timing of capital expenditures, including future exploration and development costs;
- the availability and terms of capital;
- our drilling of wells;
- our ability to negotiate and consummate acquisition and divestiture opportunities;
- government regulation and taxation of the oil and natural gas industry;
- our marketing of oil and natural gas;
- our exploitation projects or property acquisitions;
- the integration of acquisitions with our business;
- our ability and the ability of our midstream joint venture to construct and operate midstream facilities, including the operation and expansion of our Black River cryogenic natural gas processing plant and the drilling of additional salt water disposal wells;
- the ability of our midstream joint venture to attract third-party volumes;
- our costs of exploiting and developing our properties and conducting other operations;
- general economic conditions;
- competition in the oil and natural gas industry, including in both the exploration and production and midstream segments;
- the effectiveness of our risk management and hedging activities;
- our technology;
- environmental liabilities;

- counterparty credit risk;
- developments in oil-producing and natural gas-producing countries;
- our future operating results; and
- our plans, objectives, expectations and intentions contained in this Annual Report or in our other filings with the SEC that are not historical.

Table of Contents

Although we believe that the expectations conveyed by the forward-looking statements in this Annual Report are reasonable based on information available to us on the date hereof, no assurances can be given as to future results, levels of activity, achievements or financial condition.

You should not place undue reliance on any forward-looking statement and should recognize that the statements are predictions of future results, which may not occur as anticipated. Actual results could differ materially from those anticipated in the forward-looking statements and from historical results, due to the risks and uncertainties described above, as well as others not now anticipated. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are interdependent upon other factors. The foregoing statements are not exclusive and further information concerning us, including factors that potentially could materially affect our financial results, may emerge from time to time. We undertake no obligation to update forward-looking statements to reflect actual results or changes in factors or assumptions affecting such forward-looking statements, except as required by law, including the securities laws of the United States and the rules and regulations of the SEC.

PART I

Item 1. Business.

In this Annual Report, references to “we,” “our” or the “Company” refer to Matador Resources Company and its subsidiaries as a whole (unless the context indicates otherwise) and references to “Matador” refer solely to Matador Resources Company. For certain oil and natural gas terms used in this Annual Report, see the “Glossary of Oil and Natural Gas Terms” included in this Annual Report.

General

We are an independent energy company engaged in the exploration, development, production and acquisition of oil and natural gas resources in the United States, with an emphasis on oil and natural gas shale and other unconventional plays. Our current operations are focused primarily on the oil and liquids-rich portion of the Wolfcamp and Bone Spring plays in the Delaware Basin in Southeast New Mexico and West Texas. We also operate in the Eagle Ford shale play in South Texas and the Haynesville shale and Cotton Valley plays in Northwest Louisiana and East Texas. Additionally, we conduct midstream operations, primarily through our midstream joint venture, San Mateo Midstream, LLC (“San Mateo”), in support of our exploration, development and production operations and provide natural gas processing, oil transportation services, oil, natural gas and salt water gathering services and salt water disposal services to third parties.

We are a Texas corporation founded in July 2003 by Joseph Wm. Foran, Chairman and CEO. Mr. Foran began his career as an oil and natural gas independent in 1983 when he founded Foran Oil Company with $270,000 in contributed capital from 17 friends and family members. Foran Oil Company was later contributed to Matador Petroleum Corporation upon its formation by Mr. Foran in 1988. Mr. Foran served as Chairman and Chief Executive Officer of that company from its inception until it was sold in June 2003 to Tom Brown, Inc., in an all cash transaction for an enterprise value of approximately $388.5 million.

On February 2, 2012, our common stock began trading on the New York Stock Exchange (the “NYSE”) under the symbol “MTDR.” Prior to trading on the NYSE, there was no established public trading market for our common stock.

Our goal is to increase shareholder value by building oil and natural gas reserves, production and cash flows at an attractive rate of return on invested capital. We plan to achieve our goal by, among other items, executing the following business strategies:

- focus our exploration and development activities primarily on unconventional plays, including the Wolfcamp and Bone Spring plays in the Delaware Basin, the Eagle Ford shale play in South Texas and the Haynesville shale and Cotton Valley plays in Northwest Louisiana and East Texas;
- identify, evaluate and develop additional oil and natural gas plays as necessary to maintain a balanced portfolio of oil and natural gas properties;
- continue to improve operational and cost efficiencies;
- identify and develop midstream opportunities that support and enhance our exploration and development activities and that generate value for San Mateo;

- maintain our financial discipline; and
- pursue opportunistic acquisitions, divestitures and joint ventures.

Despite a challenging commodity price environment since 2014, the successful execution of our business strategies in 2018 led to significant increases in our oil and natural gas production and proved oil and natural gas reserves. We also continued to increase our leasehold and minerals position in the Delaware Basin, in particular through the BLM Acquisition (as defined below). In addition, we concluded several important financing transactions in 2018, including the May 2018 public

Table of Contents

offering of 7,000,000 shares of our common stock, the refinancing and issuance of senior unsecured notes and two increases in the borrowing base under our Credit Agreement (as defined below). San Mateo also achieved several important milestones in 2018, including the completion and successful start-up of the expansion of the Black River Processing Plant (as defined below), the formation of a strategic relationship between a subsidiary of San Mateo and a subsidiary of Plains All American Pipeline, L.P. ("Plains") to gather and transport crude oil for us and third-party customers in and around the Rustler Breaks asset area, the completion and start-up of the Rustler Breaks Oil Pipeline System (as defined below), the addition of several significant third-party customers for salt water gathering and disposal and natural gas gathering and processing and the closing of the San Mateo Credit Facility (as defined below). These achievements and transactions increased our operational flexibility and opportunities while preserving the strength of our balance sheet and our liquidity position.

2018 Highlights

Increased Oil, Natural Gas and Oil Equivalent Production

For the year ended December 31, 2018, we achieved record oil, natural gas and average daily oil equivalent production. In 2018, we produced 11.1 million Bbl of oil, an increase of 42%, as compared to 7.9 million Bbl of oil produced in 2017. We also produced 47.3 Bcf of natural gas, an increase of 24% from 38.2 Bcf of natural gas produced in 2017. Our average daily oil equivalent production for the year ended December 31, 2018 was 52,128 BOE per day, including 30,524 Bbl of oil per day and 129.6 MMcf of natural gas per day, an increase of 34%, as compared to 38,936 BOE per day, including 21,510 Bbl of oil per day and 104.6 MMcf of natural gas per day, for the year ended December 31, 2017. The increase in oil and natural gas production was primarily attributable to our ongoing delineation and development drilling activities in the Delaware Basin throughout 2018, which offset declining production in the Eagle Ford and Haynesville shales where we have significantly reduced our operated activity since late 2014 and early 2015. Oil production comprised 59% of our total production (using a conversion ratio of one Bbl of oil per six Mcf of natural gas) for the year ended December 31, 2018, as compared to 55% for the year ended December 31, 2017.

Increased Oil, Natural Gas and Oil Equivalent Reserves

At December 31, 2018, our estimated total proved oil and natural gas reserves were 215.3 million BOE, including 123.4 million Bbl of oil and 551.5 Bcf of natural gas, an increase of 41% from 152.8 million BOE, including 86.7 million Bbl of oil and 396.2 Bcf of natural gas, at December 31, 2017. The associated Standardized Measure and PV-10 of our estimated total proved oil and natural gas reserves increased 79% and 93% to $2.25 billion and $2.58 billion, respectively, at December 31, 2018, from $1.26 billion and $1.33 billion, respectively, at December 31, 2017, primarily as a result of our ongoing delineation and development drilling activities in the Delaware Basin during 2018 and higher weighted average oil and natural gas prices used to estimate proved reserves. PV-10 is a non-GAAP financial measure. For a reconciliation of PV-10 to Standardized Measure, see "—Estimated Proved Reserves."

Our proved oil reserves grew 42% to 123.4 million Bbl at December 31, 2018 from 86.7 million Bbl at December 31, 2017. Our proved natural gas reserves increased 39% to 551.5 Bcf at December 31, 2018 from 396.2 Bcf at December 31, 2017. This growth in oil and natural gas reserves was primarily attributable to our ongoing delineation and development drilling activities in the Delaware Basin during 2018.

At December 31, 2018, proved developed reserves included 53.2 million Bbl of oil and 246.2 Bcf of natural gas, and proved undeveloped reserves included 70.2 million Bbl of oil and 305.2 Bcf of natural gas. Proved developed reserves and proved oil reserves comprised 44% and 57%, respectively, of our total proved oil and natural gas reserves at December 31, 2018. Proved developed reserves and proved oil reserves comprised 45% and 57%, respectively, of our total proved oil and natural gas reserves at December 31, 2017.

Operational Highlights

We focus on optimizing the development of our resource base by seeking ways to maximize our recovery per well relative to the cost incurred and to minimize our operating costs per BOE produced. We apply an analytical approach to track and monitor the effectiveness of our drilling and completion techniques and service providers. This allows us to better manage operating costs, the pace of development activities, technical applications, the gathering and marketing of our production and capital allocation. Additionally, we concentrate on our core areas, which allows us to achieve economies of scale and reduce operating costs. Largely as a result of these factors, we believe that we have increased our technical knowledge of drilling, completing and producing Delaware Basin wells, particularly over the past five years. We expect the Delaware Basin will continue to be our primary area of focus in 2019.

Table of Contents

We completed and began producing oil and natural gas from 141 gross (73.8 net) wells in the Delaware Basin in 2018, including 82 gross (66.8 net) operated and 59 gross (7.0 net) non-operated wells. We also added to and upgraded our acreage position in the Delaware Basin during 2018. As a result, at December 31, 2018, our total acreage position in the Delaware Basin had increased to approximately 222,200 gross (132,000 net) acres, primarily in Loving County, Texas and Lea and Eddy Counties, New Mexico. We have focused our Delaware Basin operations thus far on our seven main asset areas—the Wolf and Jackson Trust asset areas in Loving County, Texas, the Rustler Breaks and Arrowhead asset areas in Eddy County, New Mexico and the Antelope Ridge, Ranger and Twin Lakes asset areas in Lea County, New Mexico. Our Delaware Basin properties have become the most significant component of our asset portfolio. Our average daily oil equivalent production from the Delaware Basin increased approximately 54% to 45,237 BOE per day (87% of total oil equivalent production), including 28,026 Bbl of oil per day (92% of total oil production) and 103.3 MMcf of natural gas per day (80% of total natural gas production), in 2018, as compared to 29,463 BOE per day (76% of total oil equivalent production), including 18,023 Bbl of oil per day (84% of total oil production) and 68.6 MMcf of natural gas per day (66% of total natural gas production), in 2017. We expect our Delaware Basin production to increase in 2019 as we continue the delineation and development of these asset areas.
Operational highlights in the Delaware Basin (as further described below in "—Exploration and Production Segment—Southeast New Mexico and West Texas—Delaware Basin" and "—Midstream Segment") in 2018 included:

- in our Rustler Breaks asset area, the results from the David Edelstein State Com 12&11-24S-27E RB #203H well, our first operated two-mile horizontal well, the performance of our Wolfcamp A-XY completions moving to the northwest region of the asset area, positive tests of the Second Bone Spring formation and the continued delineation and development of previously tested horizons;
- in our Wolf asset area, the results from several wells with longer laterals (greater than one mile) drilled and completed in the Wolfcamp A-XY interval in the southern portion of the asset area;
- in our Jackson Trust asset area, the continued development of the Wolfcamp A-Lower interval;
- in our Arrowhead and Ranger asset areas, the results from our Second and Third Bone Spring completions, particularly in the SST and Stebbins acreage blocks in the Arrowhead asset area, and results from the recently completed Verna Rae Federal #204H well in the Ranger asset area, whose 24-hour initial potential ("IP") test results and subsequent well performance demonstrate the potential prospectivity of the Wolfcamp formation moving north in the Delaware Basin;
- in our Antelope Ridge asset area, the testing of six distinct intervals during 2018, including the Brushy Canyon, First, Second and Third Bone Spring, Wolfcamp A-XY and Wolfcamp A-Lower; and
- the significant progress made in our midstream operations, including (i) the completion and successful startup of the expansion of San Mateo's Black River cryogenic natural gas processing plant in the Rustler Breaks asset area (the "Black River Processing Plant") to a designed inlet capacity of 260 MMcf of natural gas per day, (ii) the completion of a natural gas liquids ("NGL") pipeline connection at the Black River Processing Plant to the NGL pipeline owned by EPIC Y-Grade Pipeline LP, (iii) the ongoing buildout of oil, natural gas and water pipeline systems in both the Rustler Breaks and Wolf asset areas, (iv) the entrance into a strategic relationship with Plains to gather and transport crude oil in the Rustler Breaks asset area, (v) placing into service crude oil gathering and transportation systems in the Wolf and Rustler Breaks asset areas, (vi) entering into long-term agreements with significant producers in Eddy County, New Mexico relating to the gathering and disposal of one such producer's salt water and the gathering and processing of another such producer's natural gas production and (vii) the drilling and completion of additional commercial salt water disposal wells and the construction of associated commercial facilities in the Rustler Breaks asset area, significantly increasing San Mateo's salt water disposal capacity.

We also completed and began producing oil and natural gas from four gross (1.5 net) wells in the Eagle Ford shale in South Texas in 2018, including one gross (1.0 net) operated and three gross (0.5 net) non-operated wells. We did not conduct any operated drilling and completion activities on our leasehold properties in Northwest Louisiana and East Texas during 2018, although we did participate in the drilling and completion of eight gross (0.2 net) non-operated Haynesville shale wells that began producing in 2018.
Financing Arrangements

We concluded several important financing transactions in 2018 that increased our operational flexibility and opportunities, while preserving the strength of our balance sheet and improving our liquidity position. These transactions included:

- the completion of a public offering of 7,000,000 shares of our common stock, whereby we received net proceeds of approximately $226.4 million;
- a series of transactions whereby we (i) issued $1.05 billion aggregate principal amount of senior notes and received net proceeds of $1.04 billion, (ii) redeemed $575.0 million aggregate principal amount of senior notes, (iii) improved the coupon rate on our senior notes outstanding to 5.875% from 6.875% and (iv) extended the maturity date of our senior notes from 2023 to 2026;

Table of Contents

- the amendment of our third amended and restated credit agreement (the “Credit Agreement”) to, among other items, (i) increase the maximum facility amount to $1.5 billion, (ii) increase the borrowing base to $850.0 million, (iii) increase the elected borrowing commitment to $500.0 million, (iv) extend the maturity to October 31, 2023, (v) reduce borrowing rates by 0.25% per annum and (vi) set the maximum leverage ratio at 4.00 to 1.00; and
- San Mateo’s entrance into a $250.0 million credit facility led by The Bank of Nova Scotia, as administrative agent (the “San Mateo Credit Facility”), and the cash distribution of $195.0 million, which was distributed 51% to us and 49% to our partner.

See “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources” for additional information regarding these financing arrangements.

BLM Acquisition

On September 12, 2018, we announced the successful acquisition of 8,400 gross and net leasehold acres in Lea and Eddy Counties, New Mexico for approximately $387 million, or a weighted average cost of approximately $46,000 per net acre, in the Bureau of Land Management (the “BLM”) New Mexico Oil and Gas Lease Sale on September 5 and 6, 2018 (the “BLM Acquisition”). The acquired leasehold acreage includes approximately 2,800 gross and net acres in the Stateline asset area on the Texas/New Mexico border, 4,800 gross and net acres in the Antelope Ridge asset area, 400 gross and net acres in the Arrowhead asset area and 400 gross and net acres in the Twin Lakes asset area. The leases for all tracts covering the BLM Acquisition were issued in the fourth quarter of 2018.

At February 26, 2019, we were actively pursuing drilling permits on a number of these tracts, including the approximately 2,800 gross and net acres in the Stateline asset area and the approximately 1,200 gross and net acres in the western portion of the Antelope Ridge asset area. We expect to begin drilling operations on these Stateline and western Antelope Ridge properties as early as the fourth quarter of 2019 or the first quarter of 2020.

Midstream Highlights

On January 22, 2018, we announced a strategic relationship between a subsidiary of San Mateo and a subsidiary of Plains to gather and transport crude oil for upstream producers in and around the Rustler Breaks asset area in Eddy County, New Mexico. Subsidiaries of San Mateo and Plains have agreed to work together through a joint tariff arrangement and related transactions to offer third-party producers located within a joint development area of approximately 400,000 acres in Eddy County, New Mexico (the “Joint Development Area”) crude oil transportation services from the wellhead to Midland, Texas with access to other end markets, such as Cushing and the Gulf Coast.

San Mateo completed its expanded oil gathering system in the Wolf asset area in Loving County, Texas (the “Wolf Oil Pipeline System”) in May 2018, and, in December 2018, San Mateo placed into service its crude oil gathering and transportation system in the Rustler Breaks asset area in Eddy County, New Mexico (the “Rustler Breaks Oil Pipeline System”) following a successful open season to gauge shipper interest in committed crude oil interstate transportation service on the Rustler Breaks Oil Pipeline System earlier in 2018.

In late March 2018, San Mateo completed the expansion of the Black River Processing Plant, adding an incremental designed inlet capacity of 200 MMcf of natural gas per day and bringing the total designed inlet capacity of the Black River Processing Plant to 260 MMcf of natural gas per day. The expanded Black River Processing Plant supports our exploration and development activities in the Delaware Basin, and with the expanded capacity, San Mateo can offer natural gas processing services to other producers as well.

In October 2018, a subsidiary of San Mateo entered into a long-term agreement with a producer in Eddy County, New Mexico relating to the gathering and processing of such producer’s natural gas production. As a result of this agreement, along with prior natural gas gathering and processing agreements entered into by San Mateo with its customers, including the Company, at December 31, 2018, San Mateo had entered into contracts to provide firm gathering and processing services for over 200 MMcf of natural gas per day, or over 80% of the designed inlet capacity of 260 MMcf of natural gas per day, at the Black River Processing Plant. In addition, in June 2018, a subsidiary of San Mateo entered into a long-term agreement with another significant producer in Eddy County, New Mexico to gather and dispose of the customer’s produced salt water. The agreement includes the dedication of certain of the third party’s wells, which are or will be located near San Mateo’s existing salt water gathering system in Eddy County, New Mexico.

2019 Recent Developments

On February 25, 2019, we announced the formation of San Mateo Midstream II, LLC (“San Mateo II”), a strategic joint venture with a subsidiary of Five Point Energy LLC (“Five Point”) designed to expand our midstream operations in the Delaware Basin, specifically in Eddy County, New Mexico. San Mateo II is owned 51% by us and 49% by Five Point. As part of this transaction, we dedicated to San Mateo II acreage in the Stebbins area and the Stateline asset area pursuant to 15-year, fixed-fee agreements for oil, natural gas and salt water gathering, natural gas processing and salt water disposal. In addition, Five Point has committed to pay $125 million of the first $150 million of capital expenditures incurred by San Mateo II to

Table of Contents

develop facilities in the Stebbins area and the Stateline asset area. Five Point has also provided us the opportunity to earn deferred performance incentives of up to $150 million over the next five years as we execute our operational plans in and around the Stebbins area and the Stateline asset area, plus additional performance incentives for securing volumes from third-party customers.

Exploration and Production Segment

Our current operations are focused primarily on the oil and liquids-rich portion of the Wolfcamp and Bone Spring plays in the Delaware Basin in Southeast New Mexico and West Texas. We also operate in the Eagle Ford shale play in South Texas and the Haynesville shale and Cotton Valley plays in Northwest Louisiana and East Texas. During 2018, we devoted most of our efforts and most of our capital expenditures to our drilling and completion operations in the Wolfcamp and Bone Spring plays in the Delaware Basin, as well as our midstream operations there. Since our inception, our exploration and development efforts have concentrated primarily on known hydrocarbon-producing basins with well-established production histories offering the potential for multiple-zone completions. We have also sought to balance the risk profile of our asset areas by exploring for and developing more conventional targets as well, although for the year ended December 31, 2018, essentially all of our efforts were focused on unconventional plays.

The following table presents certain summary data for each of our operating areas as of and for the year ended December 31, 2018.

			Producing Wells		Total Identified Drilling Locations (1)		Estimated Net Proved Reserves (2)		
	Gross Acreage	Net Acreage	Gross	Net	Gross	Net	MBOE (3)	% Developed	Avg. Daily Production (BOE/d) (3)
Southeast New Mexico/West Texas:									
Delaware Basin (4)	222,200	132,000	630	290.7	5,442	2,472.2	191,490	42.3	45,237
South Texas:									
Eagle Ford (5)	32,000	28,900	148	122.5	238	206.9	12,189	61.5	3,158
Northwest Louisiana/East Texas:									
Haynesville	19,600	12,000	227	20.4	395	100.2	10,919	46.5	3,417
Cotton Valley (6)	21,100	18,600	79	53.3	71	49.2	715	100.0	316
Area Total (7)	25,500	22,800	306	73.7	466	149.4	11,634	49.8	3,733
Total	279,700	183,700	1,084	486.9	6,146	2,828.5	215,313	43.8	52,128

---

(1) Identified and engineered drilling locations. These locations have been identified for potential future drilling and were not producing at December 31, 2018. The total net engineered drilling locations are calculated by multiplying the gross engineered drilling locations in an operating area by our working interest participation in such locations. Each location represents a one-mile lateral. At December 31, 2018, these engineered drilling locations included only 301 gross (147.6 net) locations to which we have assigned proved undeveloped reserves, primarily in the Wolfcamp or Bone Spring plays, but also in the Brushy Canyon, Avalon and Strawn formations, in the Delaware Basin, 17 gross (17.0 net) locations to which we have assigned proved undeveloped reserves in the Eagle Ford and 14 gross (4.9 net) locations to which we have assigned proved undeveloped reserves in the Haynesville.

(2) These estimates were prepared by our engineering staff and audited by Netherland, Sewell & Associates, Inc., independent reservoir engineers. For additional information regarding our oil and natural gas reserves, see "—Estimated Proved Reserves" and Supplemental Oil and Natural Gas Disclosures included in the unaudited supplementary information in this Annual Report, which is incorporated herein by reference.

(3) Production volumes and proved reserves reported in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(4) Includes potential future engineered drilling locations in the Wolfcamp, Bone Spring, Brushy Canyon, Strawn and Avalon plays on our acreage in the Delaware Basin at December 31, 2018.

(5) Includes one well producing small quantities of oil from the Austin Chalk formation and two wells producing small quantities of natural gas from the San Miguel formation in Zavala County, Texas.

(6) Includes the Cotton Valley formation and shallower zones and also includes one well producing from the Frio formation in Orange County, Texas.

(7) Some of the same leases cover the net acres shown for both the Haynesville formation and the shallower Cotton Valley formation. Therefore, the sum of the net acreage for both formations is not equal to the total net acreage for Northwest Louisiana and East Texas. This total includes acreage that we are producing from or that we believe to be prospective for these formations.

We are active both as an operator and as a co-working interest owner with various industry participants. At December 31, 2018, we operated the majority of our acreage in the Delaware Basin in Southeast New Mexico and West Texas. In those wells where we are not the operator, our working interests are often relatively small. At December 31, 2018, we also were the operator for approximately 94% of our Eagle Ford acreage and approximately 64% of our Haynesville acreage, including approximately 32% of our acreage in what we believe is the core area of the Haynesville play. A large portion of our acreage in the core area of the Haynesville shale is operated by an affiliate of Chesapeake Energy Corporation.

While we do not always have direct access to our operating partners' drilling plans with respect to future well locations on non-operated properties, we do attempt to maintain ongoing communications with the technical staff of these operators in an effort to understand their drilling plans for purposes of our capital expenditure budget and our booking of any related proved undeveloped well locations and reserves. We review these locations with Netherland, Sewell & Associates, Inc., independent reservoir engineers, on a periodic basis to ensure their concurrence with our estimates of these drilling plans and our approach to booking these reserves.

Southeast New Mexico and West Texas — Delaware Basin

The greater Permian Basin in Southeast New Mexico and West Texas is a mature exploration and production region with extensive developments in a wide variety of petroleum systems resulting in stacked target horizons in many areas. Historically, the majority of development in this basin has focused on relatively conventional reservoir targets, but the combination of advanced formation evaluation, 3-D seismic technology, horizontal drilling and hydraulic fracturing technology is enhancing the development potential of this basin, particularly in the organic rich shales, or source rocks, of the Wolfcamp formation and in the low permeability sand and carbonate reservoirs of the Bone Spring, Avalon and Delaware formations.

In the western part of the Permian Basin, also known as the Delaware Basin, the Lower Permian age Bone Spring (also called the Leonardian) and Wolfcamp formations are several thousand feet thick and contain stacked layers of shales, sandstones, limestones and dolomites. These intervals represent a complex and dynamic submarine depositional system that also includes organic rich shales that are the source rocks for oil and natural gas produced in the basin. Historically, production has come from conventional reservoirs; however, we and other industry players have realized that the source rocks also have sufficient porosity and permeability to be commercial reservoirs. In addition, the source rocks are interbedded with reservoir layers that have filled with hydrocarbons, both of which can produce significant volumes of oil and natural gas when connected by horizontal wellbores with multi-stage hydraulic fracture treatments. Particularly in the Delaware Basin, there are multiple horizontal targets in a given area that exist within the several thousand feet of hydrocarbon bearing layers that make up the Bone Spring and Wolfcamp plays. Multiple horizontal drilling and completion targets are being identified and targeted by companies, including us, throughout the vertical section, including the Brushy Canyon, Avalon, Bone Spring (First, Second and Third Sand) and several intervals within the Wolfcamp shale, often identified as Wolfcamp A through D.

As noted above in "—2018 Highlights—Operational Highlights," we increased our acreage position in the Delaware Basin during 2018, and as a result, at December 31, 2018, our total acreage position in Southeast New Mexico and West Texas was approximately 222,200 gross (132,000 net) acres, primarily in Loving County, Texas and Lea and Eddy Counties, New Mexico. These acreage totals included approximately 34,200 gross (17,500 net) acres in our Ranger asset area in Lea County, 60,100 gross (25,700 net) acres in our Arrowhead asset area in Eddy County, 45,300 gross (26,200 net) acres in our Rustler Breaks asset area in Eddy County, 20,500 gross (17,300 net) acres in our Antelope Ridge asset area in Lea County, 14,400 gross (10,700 net) acres in our Wolf and Jackson Trust asset areas in Loving County, 2,800 gross (2,800 net) acres in our recently acquired Stateline asset area in Eddy County and 44,300 gross (31,300 net) acres in our Twin Lakes asset area in Lea County at December 31, 2018. We consider the vast majority of our Delaware Basin acreage position to be prospective for oil and liquids-rich targets in the Bone Spring and Wolfcamp formations. Other potential targets on certain portions of our acreage include the Avalon and Delaware formations, as well as the Abo, Strawn, Devonian, Penn Shale, Atoka and Morrow formations. At December 31, 2018, our acreage position in the Delaware Basin was approximately 54% held by existing production. Excluding the Twin Lakes asset area, where we have drilled only one vertical operated well and two horizontal operated wells, and the acreage acquired in the BLM Acquisition, which has 10-year leases with favorable lease-holding provisions, our acreage position in the Delaware Basin was approximately 73% held by existing production at December 31, 2018.

During the year ended December 31, 2018, we continued the delineation and development of our Delaware Basin acreage. We completed and began producing oil and natural gas from 141 gross (73.8 net) wells in the Delaware Basin, including 82 gross (66.8 net) operated wells and 59 gross (7.0 net) non-operated wells, throughout our various asset areas. At December 31, 2018, we had tested a number of different producing horizons at various locations across our acreage position, including the Brushy Canyon, Avalon, the First Bone Spring, two benches of the Second Bone Spring, the Third Bone Spring, three benches of the Wolfcamp A, including the X and Y sands and the more organic, lower section of the Wolfcamp A, three benches of the Wolfcamp B, the Wolfcamp D, the Morrow and the Strawn. Most of our delineation and development efforts have been focused on multiple completion targets between the First Bone Spring and the Wolfcamp B.

As a result of our ongoing drilling and completion operations in these asset areas, our Delaware Basin production increased significantly in 2018. Our average daily oil equivalent production from the Delaware Basin increased approximately 54% to 45,237 BOE per day (87% of total oil equivalent production), including 28,026 Bbl of oil per day (92% of total oil production) and 103.3 MMcf of natural gas per day (80% of total natural gas production), in 2018, as compared to 29,463 BOE per day (76% of total oil equivalent production), including 18,023 Bbl of oil per day (84% of total oil production) and 68.6

Table of Contents

MMcf of natural gas per day (66% of total natural gas production), in 2017. Our average daily oil equivalent production from the Delaware Basin also grew approximately 41% from 34,859 BOE per day in the fourth quarter of 2017 to 49,309 BOE per day in the fourth quarter of 2018.

At December 31, 2018, approximately 89% of our estimated total proved oil and natural gas reserves, or 191.5 million BOE, was attributable to the Delaware Basin, including approximately 114.8 million Bbl of oil and 460.0 Bcf of natural gas, a 48% increase, as compared to 129.0 million BOE for the year ended December 31, 2017. Our Delaware Basin proved reserves at December 31, 2018 comprised approximately 93% of our proved oil reserves and 83% of our proved natural gas reserves, as compared to approximately 89% of our proved oil reserves and 78% of our proved natural gas reserves at December 31, 2017.

At December 31, 2018, we had identified 5,442 gross (2,472.2 net) engineered locations for potential future drilling on our Delaware Basin acreage, primarily in the Wolfcamp or Bone Spring plays, but also including the shallower Brushy Canyon and Avalon formations and the deeper Strawn formation. These locations include 3,451 gross (2,278.0 net) locations that we anticipate operating as we hold a working interest of at least 25% in each of these locations. Each horizontal drilling location assumes a one-mile lateral, although we anticipate that many of our future wells will have lateral lengths longer than one mile. These engineered locations have been identified on a property-by-property basis and take into account criteria such as anticipated geologic conditions and reservoir properties, estimated rates of return, estimated recoveries from our Delaware Basin wells and other nearby wells based on available public data, drilling densities observed on properties of other operators, estimated drilling and completion costs, spacing and other rules established by regulatory authorities and surface considerations, among other criteria. Our engineered well locations at December 31, 2018 do not yet include all portions of our acreage position and do not include any horizontal locations in our Twin Lakes asset area in Lea County, New Mexico. Our identified well locations presume that these properties may be developed on 80- to 160-acre well spacing and that multiple intervals may be prospective at any one surface location. Although we believe that denser well spacing may be possible, at December 31, 2018, the majority of our estimated locations were based on the assumption of 160-acre well spacing. As we explore and develop our Delaware Basin acreage further, we anticipate that we may identify additional locations for future drilling. At December 31, 2018, these potential future drilling locations included 301 gross (147.6 net) locations in the Delaware Basin, primarily in the Wolfcamp and Bone Spring plays, but also in the Brushy Canyon, Avalon and Strawn formations, to which we have assigned proved undeveloped reserves.

At December 31, 2018, we were operating six drilling rigs in the Delaware Basin, and we expect to operate these six rigs in the Delaware Basin throughout 2019, including two rigs in each of the Rustler Breaks and Antelope Ridge asset areas, one rig in the Wolf/Jackson Trust asset areas and one rig in the Ranger/Arrowhead and Twin Lakes asset areas. We have continued to build significant optionality into our drilling program. Three of our rigs operate on longer-term contracts with remaining average terms of approximately 12 months. The other three rigs are on short-term contracts with remaining obligations of six months or less. This affords us the ability to modify our drilling program as we may deem necessary based on changing commodity prices and other factors. We are also planning to participate in non-operated wells in the Delaware Basin as these opportunities arise in 2019.

Rustler Breaks Asset Area - Eddy County, New Mexico

We operated two to three drilling rigs in our Rustler Breaks asset area during most of 2018. We completed and turned to sales 83 gross (41.8 net) horizontal wells and two gross (1.5 net) vertical wells in the Rustler Breaks asset area in 2018, including 46 gross (38.0 net) operated and 39 gross (5.3 net) non-operated wells. Most of these wells were completed in the Wolfcamp A-XY or Wolfcamp B-Blair intervals.

One of the key achievements of our drilling and completions program in our Rustler Breaks asset area in 2018 was our first operated two-mile horizontal well—the David Edelstein State Com 12&11-24S-27E RB #203H (Edelstein #203H) well, a Wolfcamp A-XY completion. The Edelstein #203H well tested 2,378 BOE per day (77% oil) during a 24-hour IP test in the third quarter of 2018.

We were pleased in 2018 with the success of our wells drilled in the northwestern portion of our acreage position. For example, the Miss Sue 12-23S-27E RB #201H (Miss Sue #201H) and the Michael Collins 11-23S-27E RB #201H (Michael Collins #201H) wells tested 1,706 BOE per day (76% oil) and 2,125 BOE per day (78% oil), respectively, during 24-hour IP tests. The Joe Coleman 13-23S-27E RB #201H and #203H (Joe Coleman #201H and #203H) wells tested 1,702 BOE per day (80% oil) and 1,831 BOE per day (73% oil), respectively, during 24-hour IP tests. In seven months of production, the Joe Coleman #201H and #203H wells have produced approximately 210,000 BOE (69% oil) and 190,000 BOE (70% oil), respectively.

In addition, the Garrett Fed Com #122H (Garrett #122H) well, a Second Bone Spring completion in the Rustler Breaks asset area, flowed 2,411 BOE per day (84% oil) during a 24-hour IP test. We expect to further delineate the Second Bone Spring formation moving to the northwest in our Rustler Breaks asset area using two-mile laterals beginning in the latter part of 2019 or early 2020.

Wolf and Jackson Trust Asset Areas - Loving County, Texas

In the Wolf and Jackson Trust asset areas, we continued to focus primarily on the Wolfcamp A-XY and Wolfcamp A-Lower formations in 2018. We operated one drilling rig in our Wolf and Jackson Trust asset areas during 2018, and we completed and turned to sales 11 gross (8.0 net) operated horizontal wells in these asset areas. Most of these wells were completed in the Wolfcamp A-XY interval.

In the fourth quarter of 2018, we completed and placed on production the Wolf 80-TTT-B33 WF #206H and #208H (Wolf #206H and #208H) wells. These wells tested 2,509 BOE per day (41% oil) and 2,514 BOE per day (39% oil), respectively, during 24-hour IP tests. We attribute these well results to the selection of an improved landing target identified through the use of 3-D seismic data, the longer lateral lengths drilled and completed (5,600 and 6,200 feet, respectively) and an improved stimulation design.

Arrowhead and Ranger Asset Areas - Eddy and Lea Counties, New Mexico

We operated one drilling rig in our Arrowhead, Ranger and Twin Lakes asset areas during 2018. We completed and turned to sales 13 gross (7.9 net) horizontal wells in the Arrowhead and Ranger asset areas in 2018, including 10 gross (7.5 net) operated and three gross (0.4 net) non-operated wells. Most of these wells were completed in the Second Bone Spring and Third Bone Spring intervals.

The SST 6 State #123H and #124H wells, our first two Second Bone Spring wells drilled on the SST leasehold north of the Stebbins acreage in the Arrowhead asset area, tested 2,056 BOE per day (85% oil) and 1,845 BOE per day (86% oil), respectively, during 24-hour IP tests. The SST 6 State #123H well has produced approximately 240,000 BOE (70% oil) in its first eight months of production, and the SST 6 State #124H well has produced approximately 180,000 BOE (73% oil) in its first eight months of production.

In addition, we believe recent Wolfcamp wells drilled by Matador and other operators demonstrate the prospectivity of the Wolfcamp formation moving north in the Delaware Basin. We achieved positive Wolfcamp results in the Ranger asset area with the recent completion of the Verna Rae Federal Com #204H (Verna Rae #204H) well about three miles southwest of our Mallon wells. The Verna Rae #204H well flowed 1,586 BOE per day (90% oil) during a 24-hour IP test.

Antelope Ridge Asset Area - Lea County, New Mexico

We operated one to two drilling rigs in our Antelope Ridge asset area during 2018. We completed and turned to sales 29 gross (13.2 net) horizontal wells in this asset area in 2018, including 14 gross (12.3 net) operated and 15 gross (0.9 net) non-operated wells. As we began to delineate the Antelope Ridge asset area during 2018, we tested six different intervals, completing wells in the Brushy Canyon, First, Second and Third Bone Spring, Wolfcamp A-XY and Wolfcamp A-Lower.

In particular, we were pleased with our delineation of the Wolfcamp A-Lower in the Antelope Ridge asset area. The Strong 14-24S-33E AR #214H (Strong #214H) well, our second Wolfcamp A-Lower test in the Antelope Ridge asset area, flowed 3,670 BOE per day (77% oil) during a 24-hour IP test. The Strong #214H well was a successful follow-up to our initial Wolfcamp A-Lower well in the Antelope Ridge asset area, the Leo Thorsness 13-24S-33E AR #211H (Leo Thorsness #211H) well, which flowed 2,906 BOE per day (72% oil) during a 24-hour IP test. The Strong #214H well has produced approximately 225,000 BOE (75% oil) in its first four months of production, and the Leo Thorsness #211H well has produced approximately 325,000 BOE (72% oil) in its first 11 months of production.

We also achieved several strong results in the Bone Spring in the Antelope Ridge asset area. The Irvin Wall State Com #131H (Irvin Wall #131H) well, our initial Third Bone Spring test in the Antelope Ridge asset area, flowed 2,343 BOE per day (81% oil) during a 24-hour IP test. The Irvin Wall #131H well has produced approximately 150,000 BOE (85% oil) in its first seven months of production. In addition, the Bill Alexander State Com #111H (Bill Alexander #111H) well, our second First Bone Spring test in the Antelope Ridge asset area, flowed 1,808 BOE per day (79% oil) during a 24-hour IP test. The Bill Alexander #111H well was a strong follow-up test of the First Bone Spring formation north of our initial First Bone Spring completion in the Antelope Ridge asset area, the Marlan Downey 9-23S-35E AR #111H well, which tested 1,491 BOE per day (82% oil) during a 24-hour IP test. The Bill Alexander #111H well has produced approximately 175,000 BOE (80% oil) in its first seven months of production.

Twin Lakes Asset Area - Lea County, New Mexico

In 2018, we performed our first test of the Wolfcamp D formation in the western portion of our Twin Lakes asset area in northern Lea County, New Mexico. This well, the Northeast Kemnitz #233H well, tested approximately 675 BOE per day (84% oil) on electric submersible pump during a 24-hour IP test. This well has exhibited a shallow production decline similar to the D. Culbertson 26-15S-36E TL State #234H (D. Culbertson #234H) well, which was drilled and completed in 2017 and tested approximately 600 BOE per day (82% oil) during a 24-hour IP test. At December 31, 2018, we estimated an ultimate recovery of approximately 400,000 BOE from the D. Culbertson #234H well. Oil production from the D. Culbertson #234H well has been essentially flat, averaging approximately 110 Bbl of oil per day over the past 18 months, resulting in upward revisions to its estimated ultimate recovery.

Stateline Asset Area - Eddy County, New Mexico

In early September 2018, we acquired the Stateline asset area in southern Eddy County, New Mexico as part of the BLM Acquisition. The Stateline asset area includes approximately 2,800 gross and net undeveloped leasehold acres prospective for multiple geologic targets. The acquired leases are federal leases and provide an 87.5% net revenue interest (“NRI”) as compared to approximately 75% NRI on most fee leases today. As a result, we will retain an additional 17% of the net production from each well drilled and completed on these properties. The large majority of the acquired acreage is believed to be conducive to drilling longer laterals of up to two miles or more, utilizing central facilities and multi-well pad development. The BLM has formally issued these leases, and we have begun actively pursuing drilling permits on these tracts. We expect to begin drilling operations on these properties in early 2020.

South Texas — Eagle Ford Shale and Other Formations

The Eagle Ford shale extends across portions of South Texas from the Mexican border into East Texas forming a band roughly 50 to 100 miles wide and 400 miles long. The Eagle Ford is an organically rich calcareous shale and lies between the deeper Buda limestone and the shallower Austin Chalk formation. Along the entire length of the Eagle Ford trend, the structural dip of the formation is consistently down to the south with relatively few, modestly sized structural perturbations. As a result, depth of burial increases consistently southwards along with the thermal maturity of the formation. Where the Eagle Ford is shallow, it is less thermally mature and therefore more oil prone, and as it gets deeper and becomes more thermally mature, the Eagle Ford is more natural gas prone. The transition between being more oil prone and more natural gas prone includes an interval that typically produces liquids-rich natural gas with condensate.

At December 31, 2018, our properties included approximately 32,000 gross (28,900 net) acres in the Eagle Ford shale play in Atascosa, DeWitt, Gonzales, Karnes, La Salle, Wilson and Zavala Counties in South Texas. We believe that approximately 88% of our Eagle Ford acreage is prospective predominantly for oil or liquids-rich natural gas with condensate, with the remainder being prospective for less liquids-rich natural gas. Approximately 93% of our Eagle Ford acreage was held by production at December 31, 2018, and essentially all of our Eagle Ford acreage was either held by production at December 31, 2018 or not burdened by lease expirations before 2020.

In early October 2018, we added one operated drilling rig to conduct a short-term drilling program in South Texas to drill up to 10 wells, primarily in the Eagle Ford shale, to take advantage of higher oil and natural gas prices in South Texas, to conduct at least one exploratory test of the Austin Chalk formation and to validate and to hold by production almost all of our remaining undeveloped Eagle Ford acreage. This rig operated in South Texas throughout the fourth quarter of 2018 and into early 2019. When drilling operations were finalized on the ninth well in early February 2019, this rig was released and was not moved to the Delaware Basin as we had previously anticipated. One of the Eagle Ford shale wells was completed and turned to sales during the fourth quarter of 2018, and the remaining eight wells, including one well drilled in the Austin Chalk, are expected to be completed and turned to sales late in the first quarter or early in the second quarter of 2019.

Our average daily oil equivalent production from the Eagle Ford shale decreased 28% to 3,158 BOE per day, including 2,485 Bbl of oil per day and 4.0 MMcf of natural gas per day, during 2018, as compared to 4,413 BOE per day, including 3,475 Bbl of oil per day and 5.6 MMcf of natural gas per day, during 2017. For the year ended December 31, 2018, 6% of our total daily oil equivalent production was attributable to the Eagle Ford shale, as compared to 11% for the year ended December 31, 2017.

At December 31, 2018, approximately 6% of our estimated total proved oil and natural gas reserves, or 12.2 million BOE, was attributable to the Eagle Ford shale, including approximately 8.5 million Bbl of oil and 21.9 Bcf of natural gas. Our Eagle Ford total proved reserves comprised approximately 7% of our proved oil reserves and 4% of our proved natural gas reserves at December 31, 2018, as compared to approximately 11% of our proved oil reserves and 5% of our proved natural gas reserves at December 31, 2017.

At December 31, 2018, we had identified 238 gross (206.9 net) engineered locations for potential future drilling on our Eagle Ford acreage. Each drilling location assumes a one-mile lateral, although we anticipate that many of our future wells may have lateral lengths longer than one mile. These locations have been identified on a property-by-property basis and take into

Table of Contents

account criteria such as anticipated geologic conditions and reservoir properties, estimated rates of return, estimated recoveries from our producing Eagle Ford wells and other nearby wells based on available public data, drilling densities anticipated on our properties and observed on properties of other operators, estimated drilling and completion costs, spacing and other rules established by regulatory authorities and surface considerations, among other factors. The identified well locations presume that we will be able to develop our Eagle Ford properties on 40- to 80-acre spacing, depending on the specific property and the wells we have already drilled. We anticipate that any Eagle Ford wells drilled on our acreage in central and northern La Salle, northern Karnes and southern Wilson Counties can be developed on 40- to 50-acre spacing, while other properties, particularly the eastern portion of our acreage in DeWitt County, are more likely to be developed on 80-acre spacing. At December 31, 2018, these 238 gross (206.9 net) identified drilling locations included 17 gross (17.0 net) locations to which we have assigned proved undeveloped reserves.

These engineered drilling locations include only a single interval in the lower portion of the Eagle Ford shale. We believe portions of our Eagle Ford acreage may be prospective for an additional target in the lower portion of the Eagle Ford shale and for other intervals in the upper portion of the Eagle Ford shale, from which we would expect to produce predominantly oil and liquids. In addition, we believe portions of our Eagle Ford acreage may also be prospective for the Austin Chalk, Buda and other formations, from which we would expect to produce predominantly oil and liquids. At December 31, 2018, we had not included any future drilling locations in the upper portion of the Eagle Ford shale, in any additional intervals of the lower portion of the Eagle Ford shale or in the Austin Chalk or Buda formations, even though recent activity from other operators in these formations around our South Texas acreage position has demonstrated the potential prospectivity of these intervals.

Northwest Louisiana and East Texas — Haynesville Shale, Cotton Valley and Other Formations

The Haynesville shale is an organically rich, overpressured marine shale found below the Cotton Valley and Bossier formations and above the Smackover formation at depths ranging from 10,500 to 13,500 feet across a broad region throughout Northwest Louisiana and East Texas, including principally Bossier, Caddo, DeSoto and Red River Parishes in Louisiana and Harrison, Rusk, Panola and Shelby Counties in Texas. The Haynesville shale produces primarily dry natural gas with almost no associated liquids. The Bossier shale is overpressured and is often divided into lower, middle and upper units. The Cotton Valley formation is a low permeability natural gas sand that ranges in thickness from 200 to 300 feet and has porosity ranging from 6% to 10%.

We did not conduct any operated drilling and completion activities on our leasehold properties in Northwest Louisiana and East Texas during 2018, although we did participate in the drilling and completion of eight gross (0.2 net) non-operated Haynesville shale wells that were turned to sales in 2018. We do not plan to drill any operated Haynesville shale or Cotton Valley wells in 2019.

At December 31, 2018, we held approximately 25,500 gross (22,800 net) acres in Northwest Louisiana and East Texas, including 19,600 gross (12,000 net) acres in the Haynesville shale play and 21,100 gross (18,600 net) acres in the Cotton Valley play. We operate substantially all of our Cotton Valley and shallower production on our leasehold interests in Northwest Louisiana and East Texas, as well as all of our Haynesville production on the acreage outside of what we believe to be the core area of the Haynesville shale play. We operate approximately 32% of the 13,200 gross (6,400 net) acres that we consider to be in the core area of the Haynesville shale play.

For the year ended December 31, 2018, approximately 7% of our average daily oil equivalent production, or 3,733 BOE per day, including 12 Bbl of oil per day and 22.3 MMcf of natural gas per day, was attributable to our leasehold interests in Northwest Louisiana and East Texas. Natural gas production from these properties comprised approximately 17% of our daily natural gas production during 2018, as compared to approximately 29% of our daily natural gas production during 2017. During the year ended December 31, 2017, approximately 13% of our average daily oil equivalent production, or 5,060 BOE per day, including 12 Bbl of oil per day and 30.4 MMcf of natural gas per day, was attributable to our properties in Northwest Louisiana and East Texas.

For the year ended December 31, 2018, approximately 16% of our daily natural gas production, or 20.5 MMcf of natural gas per day, was produced from the Haynesville shale, with approximately 1%, or 1.8 MMcf of natural gas per day, produced from the Cotton Valley and other shallower formations on these properties. For the year ended December 31, 2017, approximately 27% of our daily natural gas production, or 28.3 MMcf of natural gas per day, was produced from the Haynesville shale, with approximately 2%, or 2.1 MMcf of natural gas per day, produced from the Cotton Valley and other shallower formations on these properties. At December 31, 2018, approximately 5% of our estimated total proved reserves, or 10.9 million BOE, was attributable to the Haynesville shale with another 0.3% of our proved reserves, or 0.7 million BOE, attributable to the Cotton Valley and shallower formations underlying this acreage.

At December 31, 2018, we had identified 395 gross (100.2 net) engineered locations for potential future drilling in the Haynesville shale play and 71 gross (49.2 net) engineered locations for potential future drilling in the Cotton Valley formation. Each drilling location assumes a one-mile lateral, although we anticipate that many of our future wells may have lateral lengths longer than one mile. These locations have been identified on a property-by-property basis and take into account criteria such as anticipated geologic conditions and reservoir properties, estimated rates of return, estimated recoveries from our producing Haynesville and Cotton Valley wells and other nearby wells based on available public data, drilling densities observed on properties of other operators, including on some of our non-operated properties, estimated drilling and completion costs, spacing and other rules established by regulatory authorities and surface conditions, among other criteria. Of the 395 gross (100.2 net) locations identified for future drilling on our Haynesville acreage, 321 gross (47.2 net) locations have been identified within the 13,200 gross (6,400 net) acres that we believe are located in the core area of the Haynesville shale play. As we explore and develop our Northwest Louisiana and East Texas acreage further, we believe it is possible that we may identify additional locations for future drilling. At December 31, 2018, these potential future drilling locations included 14 gross (4.9 net) locations in the Haynesville shale (and no locations in the Cotton Valley) to which we have assigned proved undeveloped reserves.

Midstream Segment

Our midstream segment conducts midstream operations in support of our exploration, development and production operations and provides natural gas processing, oil transportation services, oil, natural gas and salt water gathering services and salt water disposal services to third parties.

Southeast New Mexico and West Texas — Delaware Basin

On February 17, 2017, we announced the formation of San Mateo, a strategic joint venture with a subsidiary of Five Point. The midstream assets that were contributed to San Mateo included (i) the Black River Processing Plant; (ii) one salt water disposal well and a related commercial salt water disposal facility in the Rustler Breaks asset area; (iii) three salt water disposal wells and related commercial salt water disposal facilities in the Wolf asset area and (iv) substantially all related oil, natural gas and salt water gathering systems and pipelines in both the Rustler Breaks and Wolf asset areas (collectively, the “Delaware Midstream Assets”). We received $171.5 million in connection with the formation of San Mateo. We earned $14.7 million in performance incentives effective January 31, 2018, which was paid by Five Point in the first quarter of 2018. Through January 31, 2019, we had earned an additional $14.7 million in performance incentives that we expect to be paid by Five Point in the first quarter of 2019 and may earn up to an additional $44.1 million in performance incentives over the next three years. We continue to operate the Delaware Midstream Assets and retain operational control of San Mateo. The Company and Five Point own 51% and 49% of San Mateo, respectively. San Mateo continues to provide firm capacity service to us at market rates, while also being a midstream service provider to other customers in and around our Wolf and Rustler Breaks asset areas.

In February 2019, we announced an expansion of our midstream business with the formation of San Mateo II. For additional information regarding this strategic joint venture, see “—2019 Recent Developments.”

Natural Gas Gathering and Processing Assets

The Black River Processing Plant and associated gathering system were originally built to support our ongoing and future development efforts in the Rustler Breaks asset area and to provide us with firm takeaway and processing services for our Rustler Breaks natural gas production. We had previously completed the installation and testing of a 12-inch natural gas trunk line and associated gathering lines running throughout the length of our Rustler Breaks acreage position, and these natural gas gathering lines are being used to gather almost all of our operated natural gas production at Rustler Breaks.

During 2017, San Mateo began expanding the Black River Processing Plant in our Rustler Breaks asset area in Eddy County, New Mexico to add an incremental designed inlet capacity of 200 MMcf of natural gas per day to the existing designed inlet capacity of 60 MMcf of natural gas per day. As noted above in “—2018 Highlights—Midstream Highlights,” San Mateo completed this expansion of the Black River Processing Plant in late March 2018, bringing the total designed inlet capacity of the Black River Processing Plant to 260 MMcf of natural gas per day. The expanded Black River Processing Plant supports our exploration and production development activities in the Delaware Basin and offers processing opportunities for other producers’ development efforts.

As noted above in “—2018 Highlights—Midstream Highlights,” in October 2018, a subsidiary of San Mateo entered into a long-term agreement with a significant producer in Eddy County, New Mexico relating to the gathering and processing of such producer’s natural gas production. As a result of this agreement, along with prior natural gas gathering and processing agreements entered into by San Mateo with its customers, including us, at December 31, 2018, San Mateo had entered into contracts to provide firm gathering and processing services for over 200 MMcf of natural gas per day, or over 80% of the designed inlet capacity of 260 MMcf of natural gas per day, at the Black River Processing Plant.

In addition, in early 2018, San Mateo completed an NGL pipeline connection at the Black River Processing Plant to the NGL pipeline owned by EPIC Y-Grade Pipeline LP. This NGL connection provides several significant benefits to us and other San Mateo customers compared to transporting the NGLs by truck. San Mateo's customers receive (i) firm NGL takeaway out of the Delaware Basin, (ii) increased NGL recoveries, (iii) improved pricing realizations through lower transportation and fractionation costs and (iv) increased optionality through San Mateo's ability to operate the Black River Processing Plant in ethane recovery mode, if desired.

In our Wolf asset area in Loving County, Texas, San Mateo gathers our natural gas production with the natural gas gathering system we retained following the sale of our wholly-owned subsidiary that owned certain natural gas gathering and processing assets in the Wolf asset area (the "Loving County Processing System") to an affiliate of EnLink Midstream Partners, LP ("EnLink") in October 2015. The Loving County Processing System included a cryogenic natural gas processing plant (the "Wolf Processing Plant") and approximately six miles of high-pressure gathering pipeline that connected our gathering system to the Wolf Processing Plant. Substantially all of our remaining midstream assets in the Wolf asset area were contributed to San Mateo in February 2017.

At December 31, 2018, San Mateo's natural gas gathering systems included natural gas gathering pipelines and related compression and treating systems. During the year ended December 31, 2018, San Mateo gathered approximately 46.1 Bcf of natural gas, as compared to 32.1 Bcf of natural gas gathered during the year ended December 31, 2017. In addition, during the year ended December 31, 2018, San Mateo processed approximately 32.3 Bcf of natural gas, as compared to 18.4 Bcf of natural gas processed during the year ended December 31, 2017.

Crude Oil Gathering and Transportation Assets

As noted above in "—2018 Highlights—Midstream Highlights," subsidiaries of San Mateo and Plains have entered into a strategic relationship to gather and transport crude oil for upstream producers in Eddy County, New Mexico and have agreed to work together through a joint tariff arrangement and related transactions to offer producers located within the Joint Development Area crude oil transportation services from the wellhead to Midland, Texas with access to other end markets.

Also, as noted above in "—2018 Highlights—Midstream Highlights," San Mateo completed its expanded Wolf Oil Pipeline System in May 2018 and placed into service the Rustler Breaks Oil Pipeline System in December 2018. With the Wolf Oil Pipeline System and the Rustler Breaks Oil Pipeline System (collectively, the "San Mateo Oil Pipeline Systems") in service, at December 31, 2018, we estimated we had on pipe almost all of our oil production from the Wolf and Rustler Breaks asset areas, which comprised approximately 70% of our Delaware Basin oil production in the fourth quarter of 2018. With the San Mateo Oil Pipeline Systems in service, we expect to improve our oil price realizations in the Wolf and Rustler Breaks asset areas through the elimination of higher priced trucking services.

At December 31, 2018, the San Mateo Oil Pipeline Systems included crude oil gathering and transportation pipelines from origin points in Loving County, Texas and Eddy County, New Mexico to interconnects with Plains Pipeline, L.P. and two trucking facilities. During the year ended December 31, 2018, the San Mateo Oil Pipeline Systems had throughput of approximately 2.0 million Bbl of oil, as compared to 0.5 million Bbl of oil throughput during the year ended December 31, 2017.

Produced Water Gathering and Disposal Assets

During 2018, San Mateo placed into service three commercial salt water disposal wells in the Rustler Breaks asset area and placed into service one additional commercial salt water disposal well there in February 2019, bringing San Mateo's commercial salt water disposal well count in the Rustler Breaks asset area to six at February 26, 2019. In addition to its six commercial salt water disposal wells and associated facilities in the Rustler Breaks asset area, at February 26, 2019, San Mateo had three commercial salt water disposal wells and associated facilities in the Wolf asset area, and San Mateo's salt water gathering systems included salt water gathering pipelines in the Rustler Breaks and Wolf asset areas. At February 26, 2019, San Mateo had a designed disposal capacity of approximately 250,000 Bbl of salt water per day.

As noted above in "—2018 Highlights—Midstream Highlights," in June 2018, a subsidiary of San Mateo entered into a long-term agreement with a significant producer in Eddy County, New Mexico to gather and dispose of the customer's produced salt water. The agreement includes the dedication of certain of the third party's wells, which are or will be located near San Mateo's existing salt water gathering system in Eddy County, New Mexico.

During the year ended December 31, 2018, San Mateo gathered approximately 44.0 million Bbl of salt water, as compared to 20.0 million Bbl of salt water gathered during the year ended December 31, 2017. In addition, during the year ended December 31, 2018, San Mateo disposed of approximately 47.5 million Bbl of salt water, as compared to 23.6 million Bbl of salt water disposed of during the year ended December 31, 2017.

South Texas / Northwest Louisiana and East Texas

In South Texas, we own a natural gas gathering system that gathers natural gas production from certain of our operated Eagle Ford leases. In Northwest Louisiana and East Texas, we have midstream assets that gather and treat natural gas from most of our operated leases and from third parties and five non-commercial salt water disposal wells that dispose of our salt water. Our midstream assets in South Texas and Northwest Louisiana and East Texas are not part of San Mateo.

Table of Contents

Operating Summary

The following table sets forth certain unaudited production and operating data for the years ended December 31, 2018, 2017 and 2016.

	Year Ended December 31,		
	2018	2017	2016
Unaudited Production Data:			
Net Production Volumes:			
Oil (MBbl)	11,141	7,851	5,096
Natural gas (Bcf)	47.3	38.2	30.5
Total oil equivalent (MBOE) (1)	19,026	14,212	10,180
Average daily production (BOE/d) (1)	52,128	38,936	27,813
Average Sales Prices:			
Oil, without realized derivatives (per Bbl)	$57.04	$49.28	$41.19
Oil, with realized derivatives (per Bbl)	$57.38	$48.81	$42.34
Natural gas, without realized derivatives (per Mcf)	$3.49	$3.72	$2.66
Natural gas, with realized derivatives (per Mcf)	$3.46	$3.70	$2.78
Operating Expenses (per BOE):			
Production taxes, transportation and processing	$4.00	$4.10	$4.23
Lease operating	$4.89	$4.74	$5.52
Plant and other midstream services operating	$1.29	$0.92	$0.53
Depletion, depreciation and amortization	$13.94	$12.49	$11.99
General and administrative	$3.64	$4.65	$5.41

---

(1) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

The following table sets forth information regarding our production volumes, sales prices and production costs for the year ended December 31, 2018 from our operating areas, which we consider to be distinct fields for purposes of accounting for production.

	Southeast New Mexico/West Texas	South Texas	Northwest Louisiana/East Texas		
	Delaware Basin	Eagle Ford (1)	Haynesville	Cotton Valley (2)	Total
Annual Net Production Volumes					
Oil (MBbl)	10,230	907	—	4	11,141
Natural gas (Bcf)	37.7	1.5	7.5	0.6	47.3
Total oil equivalent (MBOE) (3)	16,512	1,152	1,247	115	19,026
Percentage of total annual net production	86.8 %	6.0 %	6.6 %	0.6 %	100.0 %
Average Net Daily Production Volumes					
Oil (Bbl/d)	28,026	2,485	—	12	30,523
Natural gas (MMcf/d)	103.3	4.0	20.5	1.8	129.6
Total oil equivalent (BOE/d)	45,237	3,158	3,417	316	52,128
Average Sales Prices (4)					
Oil (per Bbl)	$ 56.12	$67.40	$—	$64.72	$57.04
Natural gas (per Mcf)	$ 3.55	$5.46	$2.85	$2.80	$3.49
Total oil equivalent (per BOE)	$ 42.88	$60.02	$17.09	$18.59	$42.08
Production Costs (5)					
Lease operating, transportation and processing (per BOE)	$ 4.79	$17.25	$5.41	$19.11	$5.68

(1) Includes one well producing small volumes of oil from the Austin Chalk formation and two wells producing small quantities of natural gas from the San Miguel formation in Zavala County, Texas.
(2) Includes the Cotton Valley formation and shallower zones and also includes one well producing from the Frio formation in Orange County, Texas.
(3) Production volumes reported in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.
(4) Excludes impact of derivative settlements.

Table of Contents

(5) Excludes plant and other midstream services operating expenses, ad valorem taxes and oil and natural gas production taxes.

The following table sets forth information regarding our production volumes, sales prices and production costs for the year ended December 31, 2017 from our operating areas, which we consider to be distinct fields for purposes of accounting for production.

	Southeast New Mexico/West Texas	South Texas	Northwest Louisiana/East Texas		
	Delaware Basin	Eagle Ford (1)	Haynesville	Cotton Valley (2)	Total
Annual Net Production Volumes					
Oil (MBbl)	6,579	1,268	—	4	7,851
Natural gas (Bcf)	25.1	2.0	10.3	0.8	38.2
Total oil equivalent (MBOE) (3)	10,754	1,611	1,714	133	14,212
Percentage of total annual net production	75.7 %	11.3 %	12.1 %	0.9 %	100.0 %
Average Net Daily Production Volumes					
Oil (Bbl/d)	18,023	3,475	—	12	21,510
Natural gas (MMcf/d)	68.6	5.6	28.3	2.1	104.6
Total oil equivalent (BOE/d)	29,463	4,413	4,697	363	38,936
Average Sales Prices (4)					
Oil (per Bbl)	$ 49.08	$50.29	$—	$45.52	$49.28
Natural gas (per Mcf)	$ 4.03	$4.69	$2.83	$2.79	$3.72
Total oil equivalent (per BOE)	$ 39.41	$45.58	$16.96	$17.69	$37.20
Production Costs (5)					
Lease operating, transportation and processing (per BOE)	$ 5.80	$10.92	$4.21	$16.77	$6.29

(1) Includes one well producing small volumes of oil from the Austin Chalk formation and two wells producing small quantities of natural gas from the San Miguel formation in Zavala County, Texas.

(2) Includes the Cotton Valley formation and shallower zones and also includes one well producing from the Frio formation in Orange County, Texas.

(3) Production volumes reported in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(4) Excludes impact of derivative settlements.

(5) Excludes plant and other midstream services operating expenses, ad valorem taxes and oil and natural gas production taxes.

Table of Contents

The following table sets forth information regarding our production volumes, sales prices and production costs for the year ended December 31, 2016 from our operating areas, which we consider to be distinct fields for purposes of accounting for production.

	Southeast New Mexico/West Texas	South Texas	Northwest Louisiana/East Texas		
	Delaware Basin	Eagle Ford [1]	Haynesville	Cotton Valley [2]	Total
Annual Net Production Volumes					
Oil (MBbl)	3,805	1,286	—	5	5,096
Natural gas (Bcf)	12.2	3.1	14.3	0.9	30.5
Total oil equivalent (MBOE) [3]	5,834	1,813	2,385	148	10,180
Percentage of total annual net production	57.3 %	17.8 %	23.4 %	1.5 %	100.0 %
Average Net Daily Production Volumes					
Oil (Bbl/d)	10,395	3,517	—	12	13,924
Natural gas (MMcf/d)	33.3	8.6	39.1	2.3	83.3
Total oil equivalent (BOE/d)	15,941	4,952	6,517	403	27,813
Average Sales Prices [4]					
Oil (per Bbl)	$ 41.76	$39.49	$—	$38.78	$41.19
Natural gas (per Mcf)	$ 3.15	$3.11	$2.17	$2.27	$2.66
Total oil equivalent (per BOE)	$ 33.81	$33.46	$13.04	$14.39	$28.60
Production Costs [5]					
Lease operating, transportation and processing (per BOE)	$ 7.32	$12.74	$4.73	$17.07	$7.82

(1) Includes one well producing small volumes of oil from the Austin Chalk formation and two wells producing small quantities of natural gas from the San Miguel formation in Zavala County, Texas.

(2) Includes the Cotton Valley formation and shallower zones and also includes one well producing from the Frio formation in Orange County, Texas.

(3) Production volumes reported in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(4) Excludes impact of derivative settlements.

(5) Excludes plant and other midstream services operating expenses, ad valorem taxes and oil and natural gas production taxes.

Our total oil equivalent production of approximately 19.0 million BOE for the year ended December 31, 2018 increased 34% from our total oil equivalent production of approximately 14.2 million BOE for the year ended December 31, 2017. This increased production was primarily due to our delineation and development operations in the Delaware Basin, wh