UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 8-K

CURRENT REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE

SECURITIES EXCHANGE ACT OF 1934

Date of report (Date of earliest event reported): May 1, 2019

LAREDO PETROLEUM, INC.

(Exact name of registrant as specified in charter)

Delaware	**001-35380**	**45-3007926**
(State or other jurisdiction of incorporation or organization)	(Commission File Number)	(I.R.S. Employer Identification No.)

15 W. Sixth Street, Suite 900, Tulsa, Oklahoma	**74119**
(Address of principal executive offices)	(Zip code)

Registrant's telephone number, including area code: **(918) 513-4570**

Not Applicable

(Former name or former address, if changed since last report)

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

Title of each class	Trading Symbol	Name of each exchange on which registered
Common stock, $0.01 par value	**LPI**	**New York Stock Exchange ("NYSE")**

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

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

Item 2.02. Results of Operations and Financial Condition.

On May 1, 2019, Laredo Petroleum, Inc. (the "Company") announced its financial and operating results for the quarter ended March 31, 2019. Copies of the Company's press release and Presentation (as defined below) are furnished as Exhibit 99.1 and 99.2, respectively, to this Current Report on Form 8-K and are incorporated herein by reference. The Company plans to host a teleconference and webcast on May 2, 2019 at 7:30 am Central Time to discuss these results. To access the call, please dial 1.877.930.8286 or 1.253.336.8309 for international callers, and use conference code 8489007. A replay of the call will be available through Thursday, May 9, 2019, by dialing 1.855.859.2056, and using conference code 8489007. The webcast may be accessed at the Company's website, www.laredopetro.com, under the tab "Investor Relations."

In accordance with General Instruction B.2 of the Form 8-K, the information furnished under this Item 2.02 of this Current Report on Form 8-K and the exhibit attached hereto are deemed to be "furnished" and shall not be deemed "filed" for the purpose of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liabilities of that section, nor shall such information and exhibit be deemed incorporated by reference in any filing under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended.

Item 7.01. Regulation FD Disclosure.

On May 1, 2019, the Company issued the press release described above in Item 2.02 of this Current Report on Form 8-K. A copy of the press release is attached hereto as Exhibit 99.1 to this Current Report on Form 8-K and incorporated into this Item 7.01 by reference.

On May 1, 2019, the Company also posted to its website a Corporate Presentation (the "Presentation"). The Presentation is available on the Company's website, www.laredopetro.com, and is attached hereto as Exhibit 99.2 and incorporated into this Item 7.01 by reference.

All statements in the press release, teleconference and the Presentation, other than historical financial information, may be deemed to be forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Although the Company believes the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance, and actual results or developments may differ materially from those in the forward-looking statements. See the Company's Annual Report on Form 10-K for the year ended December 31, 2018 and the Company's other filings with the SEC for a discussion of other risks and uncertainties. The Company disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

In accordance with General Instruction B.2 of Form 8-K, the information furnished under this Item 7.01 of this Current Report on Form 8-K and the exhibit attached hereto are deemed to be "furnished" and shall not be deemed "filed" for the purpose of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liabilities of that section, nor shall such information and exhibit be deemed incorporated by reference into any filing under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended.

Item 9.01. Financial Statements and Exhibits.

(d) *Exhibits*.

Exhibit Number	Description
99.1	Press release dated May 1, 2019 announcing financial and operating results.
99.2	Presentation dated May 1, 2019.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

LAREDO PETROLEUM, INC.

Dated: May 1, 2019	By:	/s/ Michael T. Beyer
		Michael T. Beyer
		Senior Vice President & Chief Financial Officer

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Laredo Petroleum Announces 2019 First-Quarter Financial and Operating Results and Updates Full-Year 2019 Operating Plan

TULSA, OK - May 1, 2019 - Laredo Petroleum, Inc. (NYSE: LPI) ("Laredo" or "the Company") today announced its 2019 first-quarter results, reporting a net loss attributable to common stockholders of $9.5 million, or $0.04 per diluted share. Adjusted Net Income, a non-GAAP financial measure, for the first quarter of 2019 was $27.9 million, or $0.12 per diluted share. Adjusted EBITDA, a non-GAAP financial measure, for the first quarter of 2019 was $122.9 million. Please see supplemental financial information at the end of this news release for reconciliations of non-GAAP financial measures.

2019 First-Quarter Highlights

- Produced a Company record 75,276 barrels of oil equivalent ("BOE") per day, driven by continued operational efficiency improvements that resulted in 20 completions during the quarter, 33% more than originally anticipated
- Reduced combined unit lease operating expenses ("LOE") and unit cash general and administrative expense ("G&A") to $5.42 per BOE in the first quarter of 2019, an approximately 11% decrease from full-year 2018 of $6.07 per BOE, as the Company continued to focus on controllable cash costs in both field operations and corporate-level personnel expenses
- Drove down completion costs at the end of the first quarter of 2019, as the Company realized lower prices for in-basin sand and completion services, reducing per well capital costs by approximately $500,000 from originally budgeted amounts and decreasing the Company's per well capital cost to approximately $7 million per well for a 10,000-foot horizontal
- Efficiently managed capital expenditures during first-quarter 2019, resulting in a net debt to Adjusted EBITDA ratio of 1.8 times[1], which is expected to hold constant throughout 2019 as Laredo begins to generate free cash flow in the second quarter of 2019

"The strategy transition that Laredo committed to late last year is well underway," stated Randy A. Foutch, Chairman and Chief Executive Officer. "During the first quarter, we completed the two remaining packages of tightly-spaced wells and are currently wrapping up completion operations on the first package of wells developed on wider spacing sooner than expected. We have also delivered on our pledge to align personnel costs with activity levels by a recent reduction in force, which cut combined cash, non-cash and capitalized general and administrative costs by approximately 25% on an annualized basis. Most importantly, we have already improved on the plan to operate within cash flow that we put forth a little over two months ago by restructuring our oil hedges, securing additional cash flow to increase activity and substantially accelerating the time frame in which we expect to generate free cash flow while growing oil production."

"Institutional investors have fundamentally changed how they measure success for exploration and production companies over the last few years and we endeavor to listen to all of our shareholder's input on how we can better operate the Company," continued Mr. Foutch. "We have made substantial progress transitioning Laredo from a net asset value accretion philosophy to one focused on measured growth with free cash flow generation and expect to be cash flow neutral for full-year 2019, but recognize there is more work to do. We look forward to continuing our communication with all of our investors as we work together to realize our common goals."

Updated 2019 Operating Plan

Subsequent to the approval of the Company's 2019 capital plan, Laredo's expected cash flow has benefited from both tactical and strategic decisions the Company implemented to improve anticipated financial and operational performance in 2019 and beyond. The Company restructured its oil hedges in 2019 and 2020 to significantly raise the weighted-average floor price for both years, reduced in-basin sand and completion services costs from those previously budgeted by approximately 25%, settled previously announced litigation that resulted in a substantial cash payment to Laredo and delivered on the commitment to cut combined capitalized and expensed personnel costs. The Company expects to allocate the combined additional cash flows from these decisions to drilling and completion activities in 2019 and 2020. The additional activity improves Laredo's anticipated oil production versus previous guidance by approximately 3% in 2019 and by approximately 19% in 2020, while maintaining its previously-communicated target of cash flow neutrality.

The updated operating plan for 2019 increases anticipated well completions from approximately 36 gross completions to approximately 52, with the increased activity primarily in the second half of 2019. The additional activity leverages the benefits of the previous drilling and completion efficiency improvements Laredo has demonstrated in the past five years by continuously operating two drilling rigs and one completion crew through the second half of 2019.

Laredo now expects to invest approximately $465 million in 2019, excluding non-budgeted acquisitions, comprised of approximately $400 million for drilling and completion activities and approximately $65 million for production facilities, land and other capitalized costs. Activity and capital expenditures for 2019 continue to be first-half weighted, with approximately 60% of expected completions and capital expenditures occurring in the first half of 2019. The Company expects to be cash flow positive beginning in the second quarter of 2019 and to balance cash flow and capital expenditures for full-year 2019.

The Company's production profile for 2019 and 2020 should improve with this additional activity. Total production for full-year 2019 is now expected to grow approximately 11% versus full-year 2018 compared to approximately 9% in the original budget. Oil production for full-year 2019 is expected to decrease approximately 2% versus full-year 2018 compared to an approximate 5% decrease with the original budget.

The additional completions in the second half of 2019 significantly improve the Company's anticipated production for full-year 2020 versus the previous budget. Driven by the updated 2019 operating plan, Laredo now expects oil production for full-year 2020 to be approximately flat versus full-year 2019, compared to originally guided expectations of a decrease of approximately 13%. The Company's improved production profile in 2019 and 2020 better positions Laredo for mid-single digit oil production growth and free cash flow generation in 2021.

E&P Update

During the first quarter of 2019, Laredo continued to efficiently execute its operational plan, completing 20 gross (19.8 net) horizontal wells with an average completed lateral length of 10,900 feet, exceeding initial expectations of 15 gross horizontal completions. The 20 wells were completed as two 10-well packages and were the last of the tight-spacing packages the Company had previously drilled.

Both oil and total production exceeded guidance in the first quarter of 2019. Total production averaged a Company record 75,276 BOE per day, an increase of approximately 7% from the previous quarter and above Company-issued guidance of 74,000 BOE per day. First-quarter 2019 oil production averaged 28,157 BOPD, an increase of 1% from the previous quarter and exceeding Company-issued guidance by more than 2%.

In the second quarter of 2019, Laredo expects to complete 12 gross (11.5 net) horizontal wells with an average completed lateral length of approximately 11,700 feet. These wells were developed on the Company's wide-spacing development strategy. The first package to be completed during the quarter is an eight-well package co-developing two landing points in the Upper Wolfcamp formation. The second package is a four-well package developing a single landing point in the Upper Wolfcamp formation. These wider-spaced packages are expected to be more productive than the tighter-spaced packages Laredo focused on in 2017 and 2018 and are expected to improve the returns and capital efficiency of the Company's development program.

Laredo continues to take action to drive down capital costs. At the end of the first quarter of 2019, the Company realized lower pricing for completion services and in-basin sand than was budgeted, reducing the per well capital cost for a 10,000-foot horizontal well by approximately $500,000. The reduction is expected to be realized for completions through at least the end of 2019.

Additionally, the Company's continued focus on controllable cash costs reduced combined unit LOE and unit cash G&A to $5.42 per BOE in the first quarter of 2019 from $6.07 per BOE in full-year 2018. Laredo expects these combined costs to trend down on a unit basis through 2019 as the Company's reduction in force is expected to drive unit cash G&A savings and unit LOE is expected to remain among the lowest in the Midland Basin, driven by benefits derived from Laredo's field infrastructure investments.

2019 Capital Program

During the first quarter of 2019, Laredo invested approximately $144 million in drilling and completions activities. Other expenditures incurred during the quarter included approximately $4 million in bolt-on land acquisitions, lease extensions and data, approximately $9 million in infrastructure, including Laredo Midstream Services investments, and approximately $7 million in other capitalized costs.

Total costs incurred of approximately $164 million in the first quarter of 2019 was slightly below Laredo's expected capital expenditures for the quarter, putting the Company on pace to deliver on the plan to operate within cash flow.

Liquidity

At March 31, 2019, the Company had cash and cash equivalents of approximately $45 million and available capacity under its senior secured credit facility of $915 million, resulting in total liquidity of approximately $960 million.

On April 30, 2019, in connection with the semi-annual redetermination of the Company's senior secured credit facility, lenders set the Company's borrowing base at $1.1 billion.

At April 30, 2019, the Company had cash and cash equivalents of approximately $85 million and available capacity under its senior secured credit facility of $815 million, resulting in total available liquidity of approximately $900 million.

Commodity Derivatives

Subsequent to the end of the first quarter of 2019, Laredo executed a tactical restructuring of its oil hedges for the balance of 2019 and full-year 2020, and significantly increased hedged volumes in full-year 2020. This restructuring locked in WTI pricing approximately 10% higher than the Company's original budgeting and planning assumptions and approximately 25% higher than the Company's previous weighted-average floor price over the 21-month period.

Prior to the restructuring, Laredo's 2019 oil hedges were predominately puts with a weighted-average floor price of approximately $47 per barrel. The Company closed substantially all of its put contracts and in their place entered into swap contracts at a weighted-average price of $62.02 per barrel for the balance of 2019. This restructuring results in Laredo having approximately 90% of expected oil production for the balance of 2019 hedged at a weighted-average floor price of $60.42 per barrel, driving an anticipated cash flow increase of approximately $60 million as compared to the Company's initial 2019 budget.

For full-year 2020, the Company closed collars with $45 per barrel floors and entered into swap contracts at a weighted-average price of $60.28 per barrel. Laredo now has approximately 75% of anticipated oil production for full-year 2020 hedged at a weighted-average floor price of $58.79 per barrel.

Laredo has approximately 70% of its anticipated natural gas production for the balance of 2019 hedged for both product and basis. Currently, the Company has natural gas product swaps at a weighted-average Henry Hub price of $3.09 per MMBtu and WAHA/Henry Hub basis swaps at a weighted-average price of ($1.51) per MMBtu. Additionally, Laredo has hedged approximately 65% of anticipated NGL production for the balance of 2019.

The Company enters into contracts solely with banks that are part of its senior secured credit facility. Details of the Company's hedge positions are included in the current Corporate Presentation available on the Company's website at www.laredopetro.com.

Guidance

The Company is increasing its anticipated full-year 2019 total production growth guidance to approximately 11% from a previous estimate of approximately 9% and improving oil production guidance to a decrease of approximately 2% from a previous estimate of a 5% decrease, as compared to full-year 2018. The table below reflects the Company's guidance for the second quarter of 2019.

	2Q-2019E
Total production (MBOE/d)	78.5
Oil production (MBO/d)	28.5
Average sales price realizations (without derivatives):	
Oil (% of WTI)	95%
NGL (% of WTI)	20%
Natural gas (% of Henry Hub)	0%
Operating costs & expenses:	
Lease operating expenses ($/BOE)	$3.30
Production and ad valorem taxes (% of oil, NGL and natural gas revenues)	6.75%
Transportation and marketing expenses ($/BOE)	$0.75
Midstream service expenses ($/BOE)	$0.15
General and administrative:	
Cash ($/BOE)	$2.00
Non-cash stock-based compensation, net ($/BOE)	$0.65
Depletion, depreciation and amortization ($/BOE)	$9.30

Conference Call Details

On Thursday, May 2, 2019, at 7:30 a.m. CT, Laredo will host a conference call to discuss its first-quarter 2019 financial and operating results and management's outlook, the content of which is not part of this earnings release. A slide presentation providing summary financial and statistical information that will be discussed on the call will be posted to the Company's website and available for review. The Company invites interested parties to listen to the call via the Company's website at www.laredopetro.com, under the tab for "Investor Relations." Portfolio managers and analysts who would like to participate on the call should dial 877.930.8286 (international dial-in 253.336.8309), using conference code 8489007, approximately 10 minutes prior to the scheduled conference time. A telephonic replay will be available approximately two hours after the call on May 2, 2019 through Thursday, May 9, 2010. Participants may access this replay by dialing 855.859.2056, using conference code 8489007.

About Laredo

Laredo Petroleum, Inc. is an independent energy company with headquarters in Tulsa, Oklahoma. Laredo's business strategy is focused on the acquisition, exploration and development of oil and natural gas properties and midstream and marketing services, primarily in the Permian Basin of West Texas.

Additional information about Laredo may be found on its website at www.laredopetro.com.

Forward-Looking Statements

This press release and any oral statements made regarding the subject of this release, including in the conference call referenced herein, contain forward-looking statements as defined under Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, that address activities that Laredo assumes, plans, expects, believes, intends, projects, estimates or anticipates (and other similar expressions) will, should or may occur in the future are forward-looking statements. The forward-looking statements are based on management's current belief, based on currently available information, as to the outcome and timing of future events.

General risks relating to Laredo include, but are not limited to, the decline in prices of oil, natural gas liquids and natural gas and the related impact to financial statements as a result of asset impairments and revisions to reserve estimates, the increase in service and supply costs, tariffs on steel, pipeline transportation constraints in the Permian Basin, hedging activities, possible impacts of pending or potential litigation, the suspension or discontinuance of share repurchases at any time and other factors, including those and other risks described in its Annual Report on Form 10-K for the year ended December 31, 2018, and those set forth from time to time in other filings with the Securities and Exchange Commission ("SEC"). These documents are available through Laredo's website at www.laredopetro.com under the tab "Investor Relations" or through the SEC's Electronic Data Gathering and Analysis Retrieval System at www.sec.gov. Any of these factors could cause Laredo's actual results and plans to differ materially from those in the forward-looking statements. Therefore, Laredo can give no assurance that its future results will be as estimated. Laredo does not intend to, and disclaims any obligation to, update or revise any forward-looking statement.

The SEC generally permits oil and natural gas companies, in filings made with the SEC, to disclose proved reserves, which are reserve estimates that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions and certain probable and possible reserves that meet the SEC's definitions for such terms. In this press release and the conference call, the Company may use the terms "resource potential" and "estimated ultimate recovery," or "EURs," each of which the SEC guidelines restrict from being included in filings with the SEC without strict compliance with SEC definitions. These terms refer to the Company's internal estimates of unbooked hydrocarbon quantities that may be potentially added to proved reserves, largely from a specified resource play. A "resource play" is a term used by the Company to describe an accumulation of hydrocarbons known to exist over a large areal expanse and/or thick vertical section potentially supporting numerous drilling locations, which, when compared to a conventional play, typically has a lower geological and/or commercial development risk. EURs are based on the Company's previous operating experience in a given area and publicly available information relating to the operations of producers who are conducting operations in these areas. Unbooked resource potential or EURs do not constitute reserves within the meaning of the Society of Petroleum Engineer's Petroleum Resource Management System or SEC rules and do not include any proved reserves. Actual quantities of reserves that may be ultimately recovered from the Company's interests may differ substantially from those presented herein. Factors affecting ultimate recovery include the scope of the Company's ongoing drilling program, which will be directly affected by the availability of capital, decreases in oil and natural gas prices, well spacing, drilling and production costs, availability and cost of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory approvals, negative revisions to reserve estimates and other factors as well as actual drilling results, including geological and mechanical factors affecting recovery rates. Estimates of ultimate recovery from reserves may change significantly as development of the Company's core assets provides additional data. In addition, our production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases. "Type curve" refers to a production profile of a well, or a particular category of wells, for a specific play and/or area. In addition, the Company's production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases. The "standardized measure" of discounted future new cash flows is calculated in accordance with SEC regulations and a discount rate of 10%. The actual results may vary considerably and should not be considered to represent the fair market value of the Company's proved reserves.

Laredo Petroleum, Inc.
Condensed consolidated statements of operations

(in thousands, except per share data)	Three months ended March 31, 2019	Three months ended March 31, 2018
	(unaudited)	
Revenues:		
Oil, NGL and natural gas sales	$ 173,376	$ 197,434
Midstream service revenues	2,883	2,359
Sales of purchased oil	32,688	59,903
Total revenues	208,947	259,696
Costs and expenses:		
Lease operating expenses	22,609	21,951
Production and ad valorem taxes	7,219	11,812
Transportation and marketing expenses	4,759	—
Midstream service expenses	1,603	693
Costs of purchased oil	32,691	60,664
General and administrative	21,519	24,725
Depletion, depreciation and amortization	63,098	45,553
Other operating expenses	1,052	1,106
Total costs and expenses	154,550	166,504
Operating income	54,397	93,192
Non-operating income (expense):		
Gain (loss) on derivatives, net	(48,365)	9,010
Interest expense	(15,547)	(13,518)
Other, net	(72)	(2,164)
Non-operating expense, net	(63,984)	(6,672)
Income (loss) before income taxes	(9,587)	86,520
Income tax benefit:		
Deferred	96	—
Total income tax benefit	96	—
Net income (loss)	$ (9,491)	$ 86,520
Net income (loss) per common share:		
Basic	$ (0.04)	$ 0.36
Diluted	$ (0.04)	$ 0.36
Weighted-average common shares outstanding:		
Basic	230,476	238,228
Diluted	230,476	239,319

Laredo Petroleum, Inc.
Condensed consolidated statements of cash flows

(in thousands)	Three months ended March 31, 2019	2018
	(unaudited)	
Cash flows from operating activities:		
Net income (loss)	$ (9,491)	$ 86,520
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Deferred income tax benefit	(96)	—
Depletion, depreciation and amortization	63,098	45,553
Non-cash stock-based compensation, net	7,406	9,339
Mark-to-market on derivatives:		
(Gain) loss on derivatives, net	48,365	(9,010)
Settlements received (paid) for matured derivatives, net	102	(2,236)
Premiums paid for derivatives	(4,016)	(4,024)
Other, net	7,776	5,308
Cash flows from operating activities before changes in assets and liabilities	113,144	131,450
(Increase) decrease in current assets and liabilities, net	(36,750)	15,495
Decrease (increase) in other noncurrent assets and liabilities, net	1,064	(474)
Net cash provided by operating activities	77,458	146,471
Cash flows from investing activities:		
Capital expenditures:		
Oil and natural gas properties	(152,729)	(195,025)
Midstream service assets	(2,262)	(3,362)
Other fixed assets	(505)	(3,963)
Proceeds from disposition of equity method investee, net of selling costs	—	1,655
Proceeds from dispositions of capital assets, net of selling costs	43	1,021
Net cash used in investing activities	(155,453)	(199,674)
Cash flows from financing activities:		
Borrowings on Senior Secured Credit Facility	80,000	55,000
Share repurchases	—	(53,714)
Stock exchanged for tax withholding	(2,612)	(4,353)
Net cash provided by (used in) financing activities	77,388	(3,067)
Net decrease in cash and cash equivalents	(607)	(56,270)
Cash and cash equivalents, beginning of period	45,151	112,159
Cash and cash equivalents, end of period	$ 44,544	$ 55,889

Laredo Petroleum, Inc.
Selected operating data

	Three months ended March 31,	
	2019	2018
	(unaudited)	
Sales volumes:		
Oil (MBbl)	2,534	2,439
NGL (MBbl)	2,099	1,563
Natural gas (MMcf)	12,849	10,173
Oil equivalents (MBOE)(1)(2)	6,775	5,698
Average daily sales volumes (BOE/D)(2)	75,276	63,314
% Oil(2)	37%	43%
Average sales prices(2):		
Oil, without derivatives ($/Bbl)(3)	$ 50.97	$ 61.87
NGL, without derivatives ($/Bbl)(3)	$ 15.36	$ 18.14
Natural gas, without derivatives ($/Mcf)(3)	$ 0.93	$ 1.79
Average price, without derivatives ($/BOE)(3)	$ 25.59	$ 34.65
Oil, with derivatives ($/Bbl)(4)	$ 47.66	$ 58.53
NGL, with derivatives ($/Bbl)(4)	$ 15.33	$ 18.11
Natural gas, with derivatives ($/Mcf)(4)	$ 1.11	$ 1.85
Average price, with derivatives ($/BOE)(4)	$ 24.68	$ 33.34
Average costs and expenses per BOE sold(2):		
Lease operating expenses	$ 3.34	$ 3.85
Production and ad valorem taxes	1.07	2.07
Transportation and marketing expenses	0.70	—
Midstream service expenses	0.24	0.12
General and administrative:		
Cash	2.08	2.70
Non-cash stock-based compensation, net	1.09	1.64
Depletion, depreciation and amortization	9.31	7.99
Total costs and expenses	$ 17.83	$ 18.37
Cash margins per BOE sold(2)(5):		
Realized	$ 18.16	$ 25.91
Hedged	$ 17.25	$ 24.60

(1) BOE is calculated using a conversion rate of six Mcf per one Bbl.

(2) The numbers presented are based on actual results and are not calculated using the rounded numbers presented in the table above.

(3) Realized oil, NGL and natural gas prices are the actual prices received when control passes to the purchaser/customer adjusted for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead.

(4) Price reflects the after-effects of our derivative transactions on our average sales prices. Our calculation of such after-effects includes settlements of matured derivatives during the respective periods in accordance with GAAP and an adjustment to reflect premiums incurred previously or upon settlement that are attributable to derivatives that settled during the respective periods.

(5) On a per BOE basis, cash margins are calculated as average price less, (i) lease operating expenses, (ii) production and ad valorem taxes, (iii) transportation and marketing expenses, (iv) midstream service expenses and (v) cash general and administrative.

Laredo Petroleum, Inc.
Costs incurred

The following table presents costs incurred in the acquisition, exploration and development of oil and natural gas properties, with asset retirement obligations included in development costs, for the periods presented:

	Three months ended March 31,	
(in thousands)	**2019**	**2018**
	(unaudited)	
Property acquisition costs:		
Evaluated	$ —	$ —
Unevaluated	—	—
Exploration costs	7,505	6,137
Development costs	152,717	149,038
Total costs incurred	$ 160,222	$ 155,175

Laredo Petroleum, Inc.
Supplemental reconciliations of GAAP to non-GAAP financial measures

Non-GAAP financial measures

The non-GAAP financial measures of Adjusted Net Income and Adjusted EBITDA, as defined by us, may not be comparable to similarly titled measures used by other companies. Therefore, these non-GAAP measures should be considered in conjunction with net income or loss and other performance measures prepared in accordance with GAAP, such as operating income or loss or cash flows from operating activities. Adjusted Net Income and Adjusted EBITDA should not be considered in isolation or as a substitute for GAAP measures, such as net income or loss, operating income or loss or any other GAAP measure of liquidity or financial performance.

Adjusted Net Income (Unaudited)

Adjusted Net Income is a non-GAAP financial measure we use to evaluate performance, prior to income taxes, mark-to-market on derivatives, premiums paid for derivatives, gains or losses on disposal of assets and other non-recurring income and expenses and after applying adjusted income tax expense. We believe Adjusted Net Income helps investors in the oil and natural gas industry to measure and compare our performance to other oil and natural gas companies by excluding from the calculation items that can vary significantly from company to company depending upon accounting methods, the book value of assets and other non-operational factors.

Including a higher weighted-average common shares outstanding in the denominator of a diluted per share computation results in an anti-dilutive per share amount when an entity is in a loss position. As such, our net income (loss) (GAAP) per common share calculation utilizes the same denominator for both basic and diluted net income (loss) per common share. However, our calculation of Adjusted Net Income (non-GAAP) results in income for both periods presented. Therefore, we believe it appropriate and more conservative to calculate an adjusted diluted weighted-average common shares outstanding utilizing our fully dilutive weighted-average common shares. As such, we present a line item that calculates Adjusted Net Income per adjusted diluted common share.

The following table presents a reconciliation of income (loss) before income taxes (GAAP) to Adjusted Net Income (non-GAAP):

	Three months ended March 31,	
(in thousands, except per share data)	**2019**	**2018**
	(unaudited)	
Income (loss) before income taxes	$ (9,587)	$ 86,520
Plus:		
Mark-to-market on derivatives:		
(Gain) loss on derivatives, net	48,365	(9,010)
Settlements received (paid) for matured derivatives, net	102	(2,236)
Premiums paid for derivatives	(4,016)	(4,024)
Loss on disposal of assets, net	939	2,617
Adjusted income before adjusted income tax expense	35,803	73,867
Adjusted income tax expense(1)	(7,877)	(16,251)
Adjusted Net Income	$ 27,926	$ 57,616
Net income (loss) per common share:		
Basic	$ (0.04)	$ 0.36
Diluted	$ (0.04)	$ 0.36
Adjusted Net Income per common share:		
Basic	$ 0.12	$ 0.24
Adjusted diluted	$ 0.12	$ 0.24
Weighted-average common shares outstanding:		
Basic	230,476	238,228
Diluted	230,476	239,319
Adjusted diluted	231,531	239,319

(1) Adjusted income tax expense is calculated by applying a statutory tax rate of 22% for each of the three months ended March 31, 2019 and 2018.

Adjusted EBITDA (Unaudited)

Adjusted EBITDA is a non-GAAP financial measure that we define as net income or loss plus adjustments for income taxes, depletion, depreciation and amortization, non-cash stock-based compensation, net, accretion expense, mark-to-market on derivatives, premiums paid for derivatives, interest expense, gains or losses on disposal of assets and other non-recurring income and expenses. Adjusted EBITDA provides no information regarding a company's capital structure, borrowings, interest costs, capital expenditures, working capital movement or tax position. Adjusted EBITDA does not represent funds available for discretionary use because those funds are required for debt service, capital expenditures, working capital, income taxes, franchise taxes and other commitments and obligations. However, our management believes Adjusted EBITDA is useful to an investor in evaluating our operating performance because this measure:

- is widely used by investors in the oil and natural gas industry to measure a company's operating performance without regard to items excluded from the calculation of such term, which can vary substantially from company to company depending upon accounting methods, the book value of assets, capital structure and the method by which assets were acquired, among other factors;

- helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure from our operating structure; and

- is used by our management for various purposes, including as a measure of operating performance, in presentations to our board of directors and as a basis for strategic planning and forecasting.

There are significant limitations to the use of Adjusted EBITDA as a measure of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect our net income or loss, the lack of comparability of results of operations to different companies and the different methods of calculating Adjusted EBITDA reported by different companies. Our measurements of Adjusted EBITDA for financial reporting as compared to compliance under our debt agreements differ.

The following table presents a reconciliation of net income (loss) (GAAP) to Adjusted EBITDA (non-GAAP):

	Three months ended March 31,	
(in thousands)	**2019**	**2018**
	(unaudited)	
Net income (loss)	$ (9,491)	$ 86,520
Plus:		
Deferred income tax benefit	(96)	—
Depletion, depreciation and amortization	63,098	45,553
Non-cash stock-based compensation, net	7,406	9,339
Accretion expense	1,052	1,106
Mark-to-market on derivatives:		
(Gain) loss on derivatives, net	48,365	(9,010)
Settlements received (paid) for matured derivatives, net	102	(2,236)
Premiums paid for derivatives	(4,016)	(4,024)
Interest expense	15,547	13,518
Loss on disposal of assets, net	939	2,617
Adjusted EBITDA	$ 122,906	$ 143,383

[1]Net Debt to Adjusted EBITDA

Net debt to Adjusted EBITDA is calculated as net debt as of March 31, 2019 divided by trailing twelve-month Adjusted EBITDA ending March 31, 2019 of $568 million. Net debt as of March 31, 2019 was $1.025 billion, calculated as the face value of debt of $1.070 billion reduced by cash and cash equivalents of $45 million.

# # #

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L A R E D O   P E T R O L E U M

First-Quarter 2019
Earnings Presentation

Forward-Looking / Cautionary Statements

This presentation, including any oral statements made regarding the contents of this presentation, contains forward-looking statements as defined under Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, that address activities that Laredo Petroleum, Inc. (together with its subsidiaries, the "Company", "Laredo" or "LPI") assumes, plans, expects, believes, intends, projects, estimates or anticipates (and other similar expressions) will, should or may occur in the future, including, but not limited to, the share repurchase program, which may be suspended or discontinued by the Company at any time, are forward-looking statements. The forward-looking statements are based on management's current belief, based on currently available information, as to the outcome and timing of future events.

General risks relating to Laredo include, but are not limited to, the decline in prices of oil, natural gas liquids and natural gas and the related impact to financial statements as a result of asset impairments and revisions to reserve estimates, the increase in service costs, hedging activities, possible impacts of pending or potential litigation and other factors, including those and other risks described in its Annual Report on Form 10-K for the year ended December 31, 2018, and those set forth from time to time in other filings with the Securities Exchange Commission ("SEC") including, but not limited to, its Annual Report on Form 10-K for the year ended December 31, 2018, to be filed with the SEC. These documents are available through Laredo's website at www.laredopetro.com under the tab "Investor Relations" or through the SEC's Electronic Data Gathering and Analysis Retrieval System at www.sec.gov. Any of these factors could cause Laredo's actual results and plans to differ materially from those in the forward-looking statements. Therefore, Laredo can give no assurance that its future results will be as estimated. Laredo does not intend to, and disclaims any obligation to, update or revise any forward-looking statement.

Any forward-looking statement speaks only as of the date on which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

The SEC generally permits oil and natural gas companies, in filings made with the SEC, to disclose proved reserves, which are reserve estimates that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions and certain probable and possible reserves that meet the SEC's definitions for such terms. In this presentation, the Company may use the terms "resource potential," "estimated ultimate recovery" ("EURs") or "type curve," each of which the SEC guidelines restrict from being included in filings with the SEC without strict compliance with SEC definitions. These terms refer to the Company's internal estimates of unbooked hydrocarbon quantities that may be potentially discovered through exploratory drilling or recovered with additional drilling or recovery techniques. "Resource potential" is used by the Company to refer to the estimated quantities of hydrocarbons that may be added to proved reserves, largely from a specified resource play potentially supporting numerous drilling locations. A "resource play" is a term used by the Company to describe an accumulation of hydrocarbons known to exist over a large areal expanse and/or thick vertical section potentially supporting numerous drilling locations, which, when compared to a conventional play, typically has a lower geological and/or commercial development risk. "Estimated ultimate recovery," or "EURs," are based on the Company's previous operating experience in a given area and publicly available information relating o the operations of producers who are conducting operations in these areas. Unbooked resource potential or EURs do not constitute reserves within the meaning of the Society of Petroleum Engineer's Petroleum Resource Management System or SEC rules and do not include any proved reserves. Actual quantities of reserves that may be ultimately recovered from the Company's interests may differ substantially from those presented herein. Factors affecting ultimate recovery include the scope of the Company's ongoing drilling program, which will be directly affected by the availability of capital, decreases in oil, natural gas liquids and natural gas prices, well spacing, drilling costs and production costs, availability and costs of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory approvals, negative revisions to reserve estimates and other factors as well as actual drilling results, including geological and mechanical factors affecting recovery rates. Estimates of EURs may change significantly as development of the Company's core assets provides additional data. In addition, our production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases. "Type curve" refers to a production profile of a well, or a particular category of wells, for a specific play and/or area. In addition, the Company's production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases.

This presentation includes financial measures that are not in accordance with generally accepted accounting principles ("GAAP"), including Adjusted EBITDA. While management believes that such measures are useful for investors, they should not be used as a replacement for financial measures that are in accordance with GAAP. For a reconciliation of Adjusted EBITDA to the nearest comparable measure in accordance with GAAP, please see the Appendix.

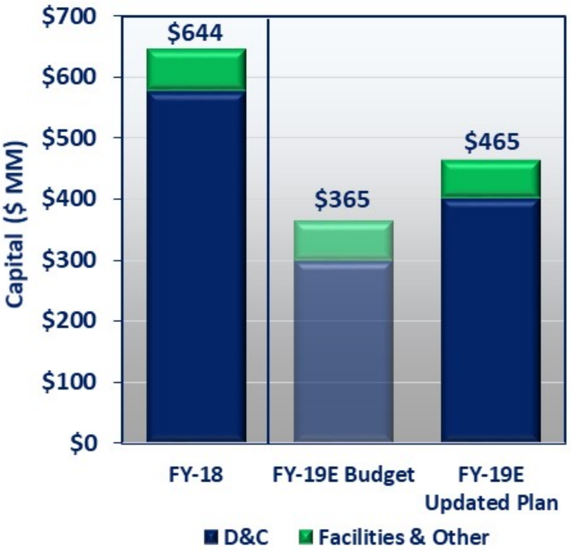
"Type curve" refers to a production profile of a well, or a particular category of wells, for a specific play and/or area. In addition, the Company's production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases. The "standardized measure" of discounted future new cash flows is calculated in accordance with SEC regulations and a discount rate of 10%. The actual results may vary considerably and should not be considered to represent the fair market value of the Company's proved reserves.

2019: A Transitional Year

Operating within Cash Flow	▪ Tailoring operational cadence & corporate cost structure to balance capital expenditures and cash flow from operations ▪ Protected cash flow by restructuring Bal-19 and FY-20 hedges, increasing the wtd.-avg. WTI floors to $60.42/BO & $58.79/BO for Bal-19 & FY-20, respectively
Optimized Operations	▪ ~$700,000 of negotiated Bal-19 per-well savings, reducing YE-18 well costs by ~9% and bolstering per-well returns by ~5% ▪ Widening of spacing is anticipated to improve well results, rates of return and capital efficiency versus FY-18
Reconstructed Management Team	▪ Named new President and announced CEO succession plan ▪ Promoted new COO, CFO & General Counsel, and reduced officer-level positions by ~40%
Right-Sized Employee Base	▪ ~20% reduction in employee base ▪ ~$20 MM of YoY FY-19E cash & non-cash G&A expense & capitalized savings ▪ ~$10 MM of additional annual cash & non-cash G&A expense & capitalized savings expected beyond FY-19

Strategy evolution is expected to drive long-term capital efficiency improvements and higher returns versus 2018

2019 Capital Program Demonstrates Flexibility & Discipline



	FY-19E Budget	FY-19E Updated Plan
Average FY Rig Count	1.8	2.3
Average FY Completions Crew Count	0.9	1.3
Completions Activity	Thru July	FY-19
# Gross Completions	~36	~52
YoY Production Growth - BOE	+9%	+11%
YoY Production Growth - BO	(-5%)	(-2%)

Higher FY-19 operational cadence underpinned by hedge restructure while maintaining focus on cash flow neutrality

Note: Excludes non-budgeted acquisitions & includes cash & non-cash capital
FY-19E budget capital plan based on $54/BO WTI & $2.90/MMBtu HH
FY-19E updated capital plan based on $58/BO WTI & $2.90/MMBtu HH

Restructured Hedges Underpin Updated Plan

Original Budget – Bal-19

$54.00 Per BO	$47.91 Per BO
Internal Price Deck	Weighted-Avg. Floor
~90%	(-5%)
Hedged Production	YoY Oil Growth

Original Budget – FY-20

$54.15 Per BO	$47.27 Per BO
Internal Price Deck	Weighted-Avg. Floor
~20%	(-13%)
Hedged Production	YoY Oil Growth

Updated Plan – Bal-19

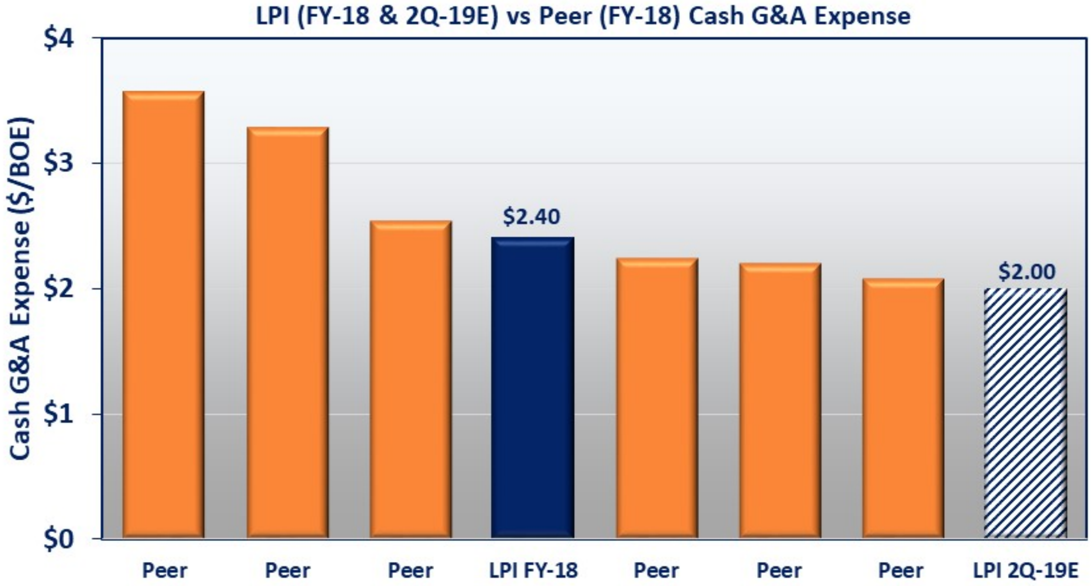
$59.25 Per BO	$60.42 Per BO
Internal Price Deck	Weighted-Avg. Floor
~90%	(-2%)
Hedged Production	YoY Oil Growth

Updated Plan – FY-20

$58.00 Per BO	$58.79 Per BO
Internal Price Deck	Weighted-Avg. Floor
~75%	~flat
Hedged Production	YoY Oil Growth

Updated plan improves expected YoY oil production within protected cash flow by 3% and 19% in FY-19 & FY-20, respectively

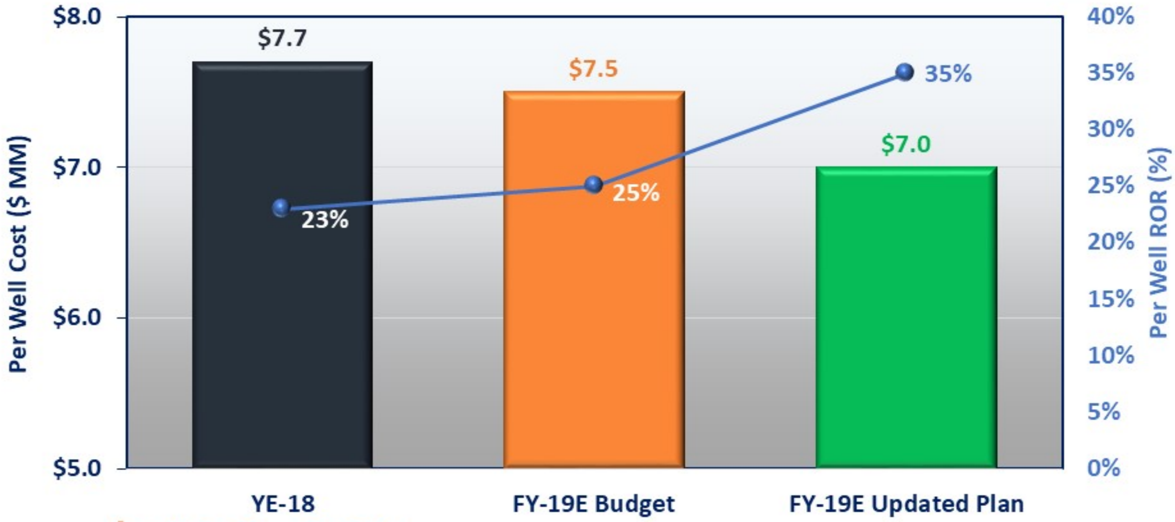
Right Sized Our Cost Structure As Promised



~$30 MM YoY annualized cash & non-cash G&A expense & capitalized savings expected

Note: Peers include: CPE, CXO, PE, PXD, QEP, SM

Improving Well Costs & Higher Pricing Bolster Well Returns



~$700,000 Per well savings captured since YE-18

Higher pricing & well cost savings are improving per well returns by ~12%

Note: Well costs indicative of a 10,000' UWC/MWC utilizing a 2-well pad
YE-18 and FY-19E budget returns are based on pricing of $54/BO WTI & $2.90/MMBtu HH
FY-19E updated plan returns are based on pricing of $58/BO WTI & $2.90/MMBtu HH

Delivering on Wider Spacing Earlier than Promised

Formation	Development Zone	Wells per DSU	
		NAV/ Tight Spacing	ROR/ Wide Spacing
UWC	UW-AB UW-CD UWE-MWA	12 - 16 Wells	4 - 8 Wells
MWC	MW-B MW-C MW-D	12 - 16 Wells	4 - 8 Wells
LWC	LW-AB LW-C	6 - 8 Wells	4 Wells
Cline	CLINE-AB CLINE-CD	6 - 8 Wells	4 Wells
Total Well Count per DSU		36 - 48 Wells	16 - 24 Wells

All second quarter completions will be developed in the UWC/MWC at 4 - 8 wells per DSU

Note: Excludes ABW, Canyon and Spraberry formations
Drilling spacing unit (DSU)

1Q-19 Production and Controllable Cash Costs Versus Guidance

Oil Production (MBO/d)

Production (MBOE/d)

Lease Operating Expense ($/BOE)

$3.34/BOE

G&A Cash Expense ($/BOE)

$2.08/BOE

G&A Non-Cash Expense ($/BOE)

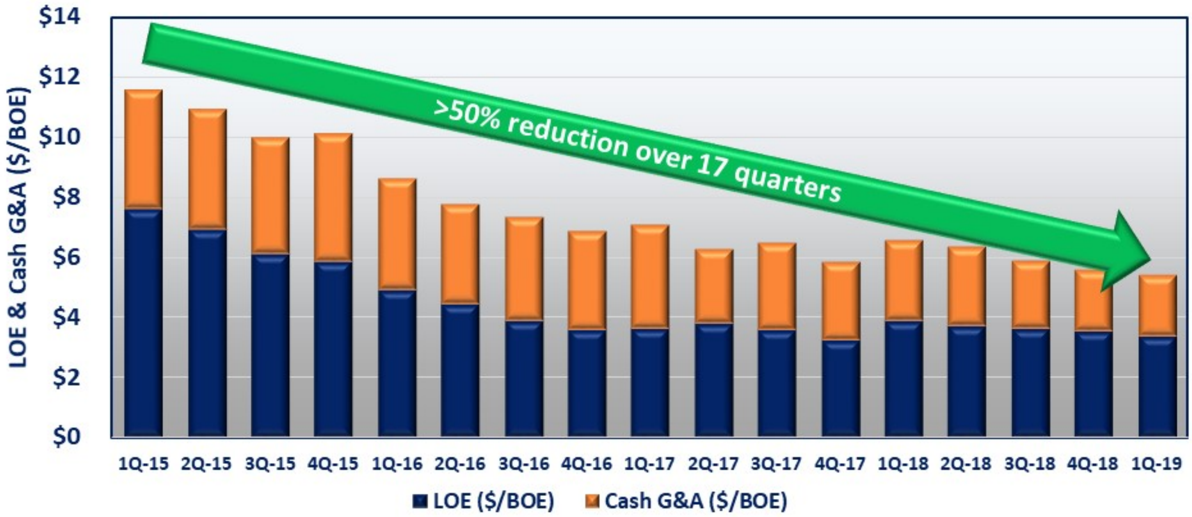
$1.09/BOE

1Q-19 Highlights

~33%	~11%	>2%	$500 M	~1.8x
More completions than originally anticipated	Decrease in unit LOE & unit cash G&A expense from FY-18 average	Oil production beat vs 1Q-19 guidance	Decrease in per well costs versus original budget	Net debt to Adjusted EBITDA[1]

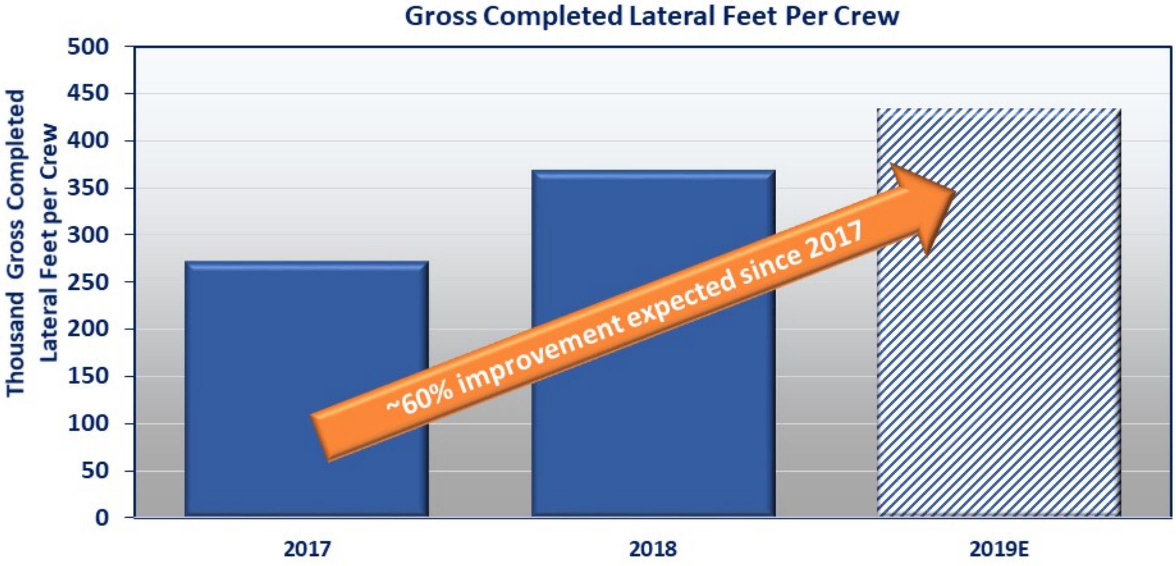
[1]Net debt to Adjusted EBITDA is calculated as net debt as of March 31, 2019 divided by trailing twelve-month Adjusted EBITDA ending March 31, 2019 of $568 million. Net debt as of March 31, 2019 was $1,025 million, calculated as the face value of long-term debt of $1,070 million reduced by cash and cash equivalents of $45 million. See Appendix for a reconciliation of Net Income to Adjusted EBITDA.

Substantial Reduction in Controllable Cash Costs



Expect to continue trending down in 2019 as the previously-executed reduction in force decreases unit G&A and field infrastructure continues to drive unit LOE costs among the lowest in the Midland Basin

History of Improving Efficiencies Expected to Continue

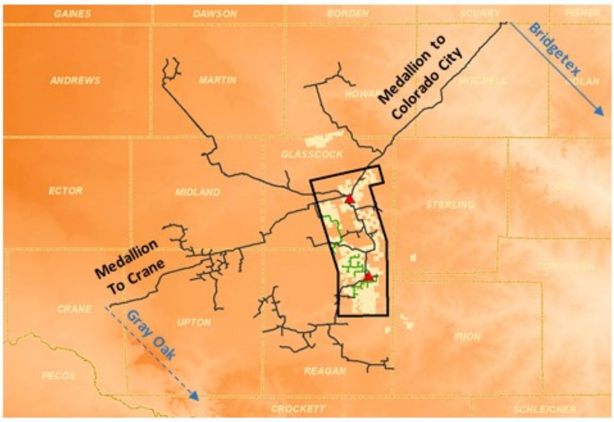


Full-year completions in the updated plan will enable Laredo's history of operational efficiency improvements to continue

Oil Value Enhanced Via Gulf Coast Access

Long-Haul Connectivity Via Medallion:

- Medallion firm transportation secured for all crude oil produced within dedication area
- Long-haul connectivity maximized, as Medallion offers delivery optionality to pipelines that connect to Cushing, Houston, Corpus Christi and Nederland markets



LPI leasehold
LMS truck stations
LMS oil gathering pipelines
Medallion-dedicated LPI acreage
Medallion intra-basin pipelines
Long-haul pipelines
Long-haul transport (constructing)

Gross Physical Transportation Contracts:

- 10 MBOPD firm transportation on Bridgetex through 1Q-22, with option to extend through 1Q-26
- Firm transportation on Gray Oak through 4Q-26E:
  - Year 1: 25 MBOPD
  - Years 2 - 7: 35 MBOPD
- Once Gray Oak Pipeline is on line, ~100% of Laredo's crude will be sold at Gulf Coast pricing
- In the event that Laredo's long-haul transportation capacity exceeds production, contracts will be fulfilled by the purchase of crude oil at Colorado City or Crane for shipment to and sale at Gulf Coast pricing

LAREDO PETROLEUM

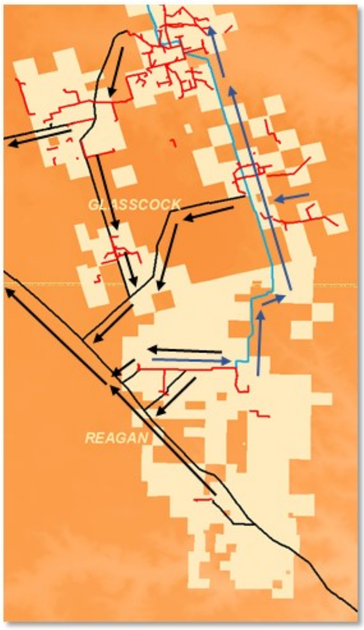
Note: Map as of 3/31/19

Natural Gas Operational Assurance & Value Protection

- LMS assets provide field-level optionality to move production to an alternate purchaser when needed
- Targa processes ~95% of LPI's liquids-rich natural gas volumes
- ~70% of bal-19E natural gas is hedged via HH swaps & Waha/HH basis swaps

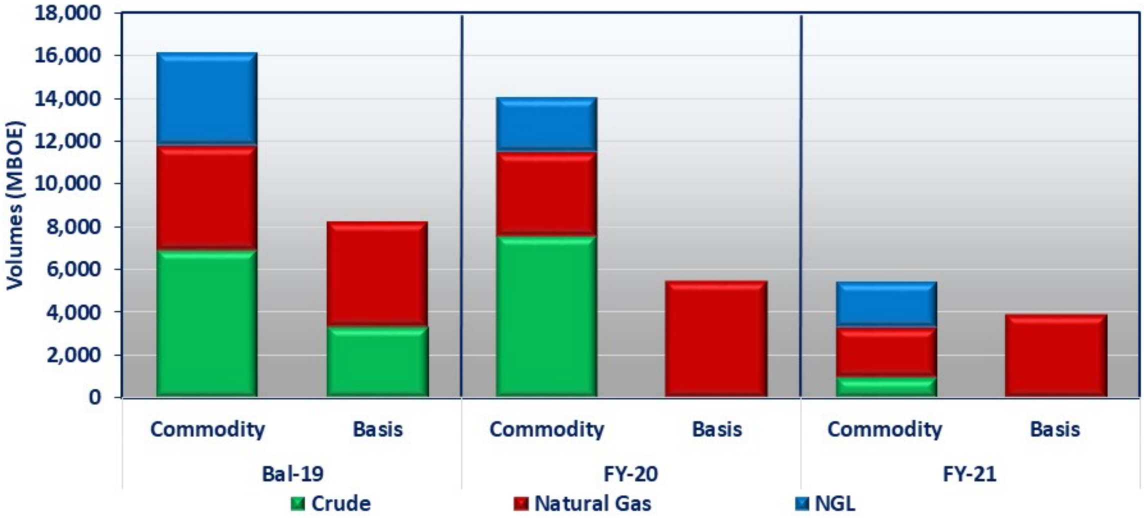
Bal-19E ($/MMBtu)	Benchmark as of 4/18/19	Hedged Wtd.-Avg. Floor Price[1]
HH	$2.64	$3.09
Waha Basis	-$1.65	-$1.51
Waha	$0.99	$1.58

60% Expected improvement in natural gas prices due to HH and Waha basis hedges



[1]Applicable to ~70% of bal-19E natural gas
Note: Map as of 3/31/19

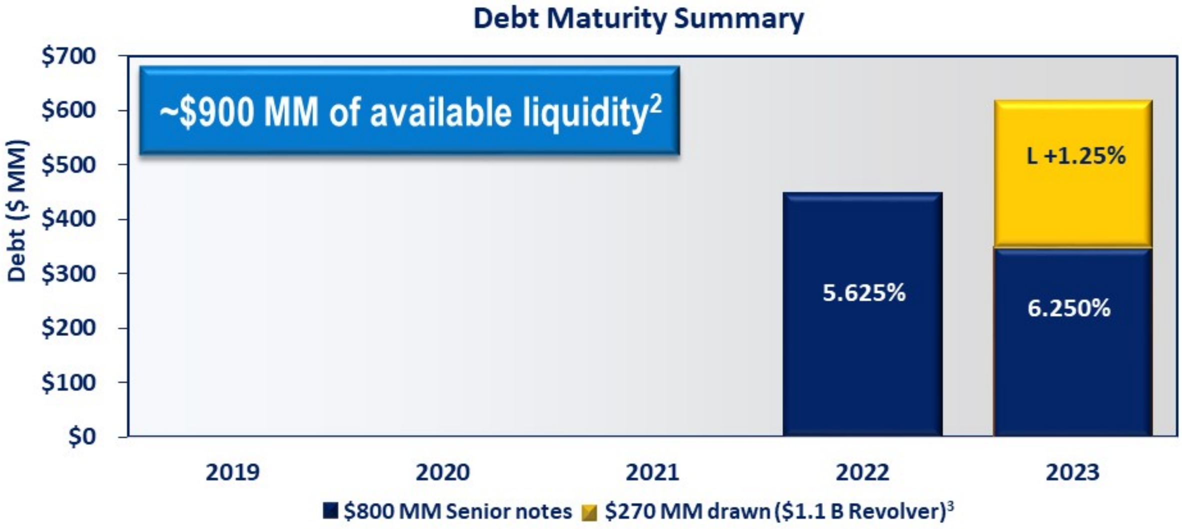
Hedging Underpins Continuous Operations



Will continue to opportunistically layer in product and basis hedges exclusively with our bank group in accordance with our physical transport and expected production

Maintaining A Strong Balance Sheet

~1.8x net debt to Adjusted EBITDA[1]



[1]Net debt to Adjusted EBITDA is calculated as net debt as of March 31, 2019 divided by trailing twelve-month Adjusted EBITDA ending March 31, 2019 of $568 million. Net debt as of March 31, 2019 was $1,025 million, calculated as the face value of long-term debt of $1,070 million reduced by cash and cash equivalents of $45 million. See Appendix for a reconciliation of Net Income to Adjusted EBITDA.

[2]As of 4/30/19, with $1.1 B aggregate elected commitment in place under Fifth Amended and Restated Senior Secured Credit Facility, decreased by the $270 MM outstanding on the Revolver, increased by cash on hand of ~$86 MM and reduced by ~$14.7 MM outstanding letter of credit

[3]As of 4/30/19, per the semi-annual redetermination of $1.1 B aggregate elected commitment in place under Fifth Amended and Restated Senior Secured Credit Facility

LAREDO PETROLEUM

Redefined Development Strategy Translates to Increased Value

Development Strategy

wider-spacing development + measured growth

- Reduce future oil decline rates
- Cash flow neutrality
- Increase ROR vs. tighter-spaced development
- Improve long-term capital efficiency

APPENDIX

2Q-19 Guidance

	2Q-19E
Total production (MBOE/d)………………………………	78.5
Oil production (MBbl/d)………………………………	28.5
Average sales price realizations (without derivatives):	
Oil (% of WTI)………………………………	95%
NGL (% of WTI)………………………………	20%
Natural gas (% of Henry Hub)………………………………	0%
Operating costs & expenses:	
Lease operating expenses ($/BOE)………………………………	$3.30
Production and ad valorem taxes (% of oil, NGL and natural gas revenues)………………………………	6.75%
Transportation and marketing expenses ($/BOE)………………………………	$0.75
Midstream service expenses ($/BOE)………………………………	$0.15
General and administrative expenses:	
Cash ($/BOE)………………………………	$2.00
Non-cash stock-based compensation, net ($/BOE)………………………………	$0.65
Depletion, depreciation and amortization ($/BOE)………………………………	$9.30

Transitional Year With a Focus on Cash Flow Neutrality

	Expected Activity	1Q-19A	2Q-19E	3Q-19E	4Q-19E
Updated Plan	Drilling Rigs	3	2	2	2
	Spuds	14	12	12	10
	Completion Crews	2.0	1.2	1.0	1.0
	Completions	20	12	9	11
Original Budget	Drilling Rigs	3	2	1	1
	Spuds	16	11	17	6
	Completion Crews	2.0	1.4	0.3	0
	Completions	15	17	4	0

Cash-flow protected updated plan enables full-year completions activity

Note: All future quarters are approximations

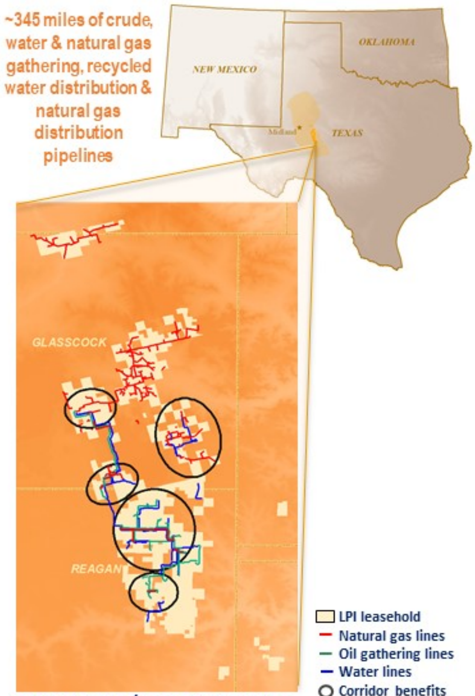
Contiguous Acreage & Robust Infrastructure Are Strategic Cornerstones

1Q-19 Infrastructure Impact

- ~$11 MM of net benefits from capital & LOE savings, price uplift and LMS net operating income
- $0.58/BOE reduction in unit LOE, helping to reduce operating costs
- ~130,000 truckloads eliminated from the field, yielding safer roads and a cleaner environment

~87%

HBP acreage, enabling a concentrated development plan along production corridors



137,512 gross/ 122,461 net acres

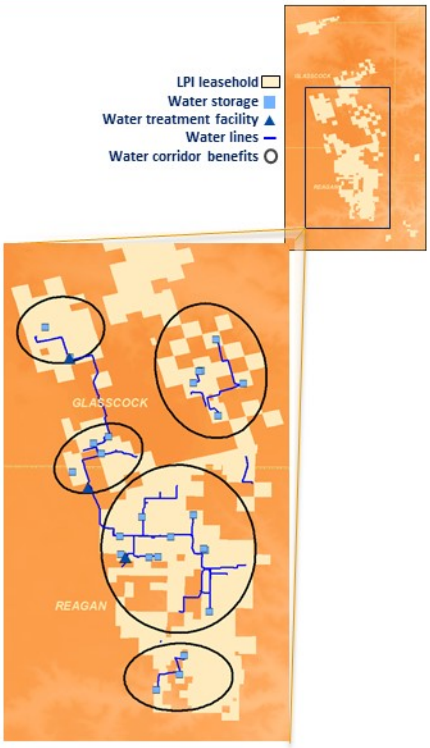
Significant Benefits Through Water Infrastructure Investments

Water Infrastructure

- ~115 miles of water gathering & distribution pipelines
- ~75% of produced water gathered by pipe and ~16% of produced water recycled in 1Q-19
- 54 MBWPD produced water recycling capacity
- 22.5 MMBW owned or contracted storage capacity

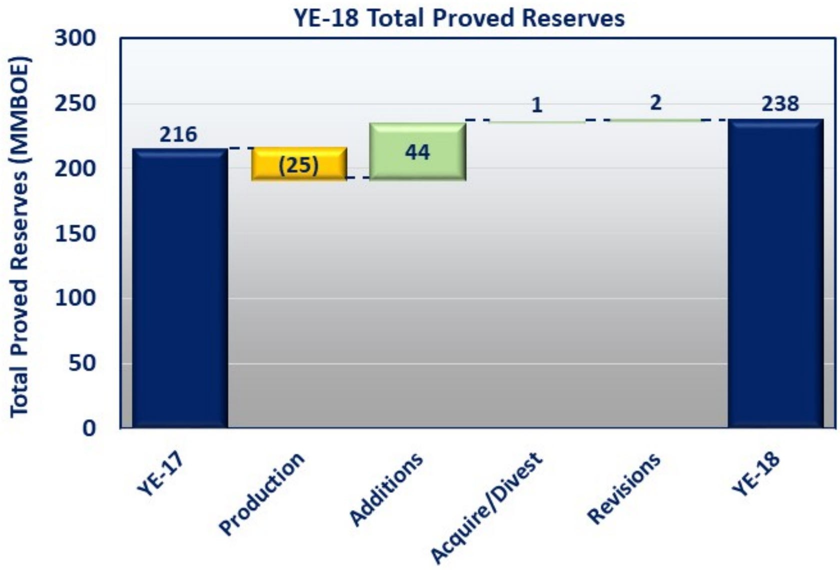
~$6.8 MM

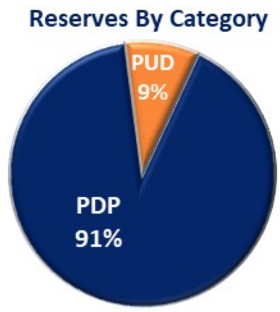
1Q-19 net savings generated by LMS water infrastructure investments[1]

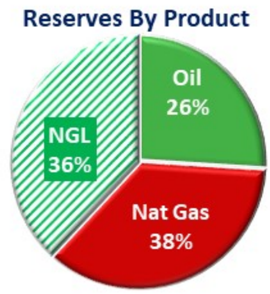


[1]Calculated utilizing a 95% WI & 72% NRI
Note: Statistics, estimates and maps as of 3/31/19

Organically Grew Total Proved Reserves in 2018



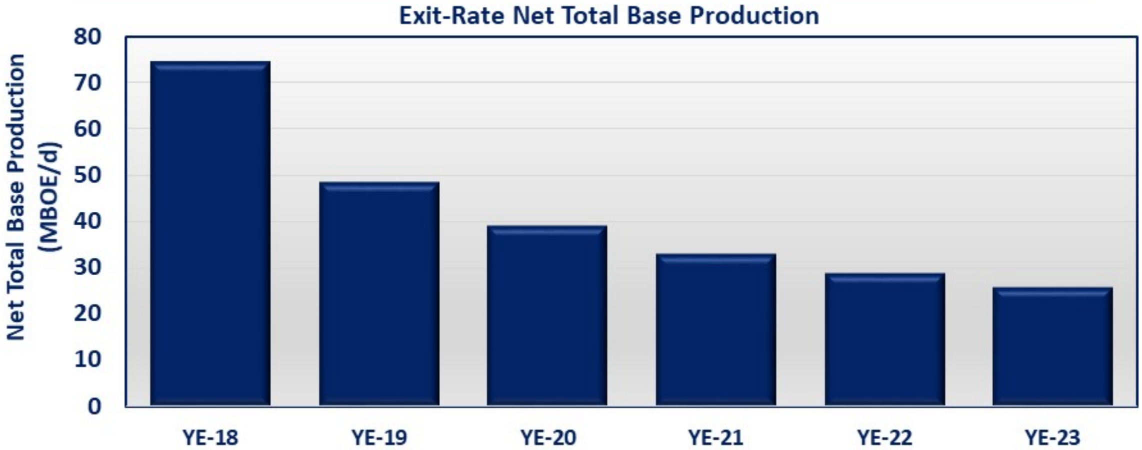




~19% YoY increase in total proved reserves value

Note: Based on estimated YE-18 3-stream proved reserves, prepared by Ryder Scott. Reserves have been rounded to the nearest 1 MMBOE

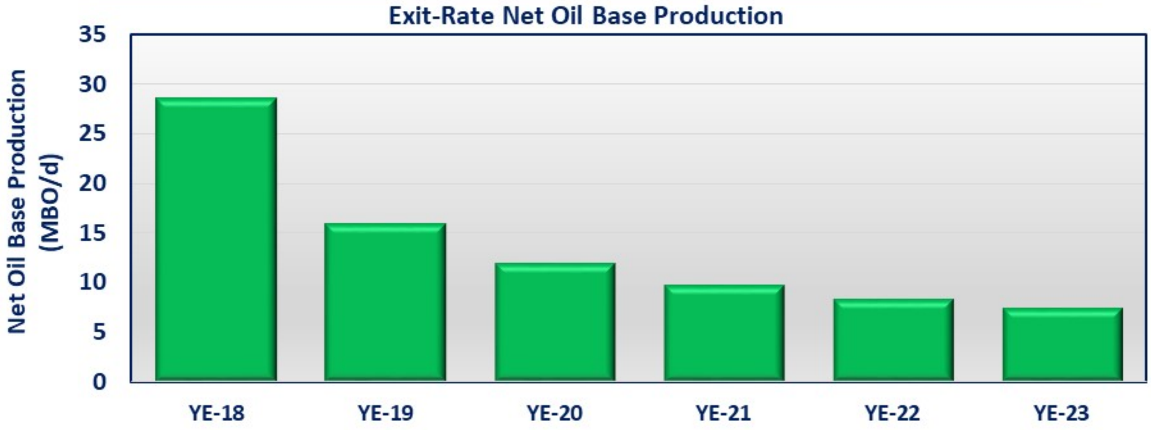
YE-18 Total PDP Reserves 5-Year Decline



	Year 1	Year 2	Year 3	Year 4	Year 5
Decline Rate	-35%	-20%	-15%	-13%	-11%

Natural gas and NGLs are exhibiting flatter declines, yielding shallower total decline rates than oil

YE-18 Oil PDP Reserves 5-Year Decline



	Year 1	Year 2	Year 3	Year 4	Year 5
Decline Rate	-44%	-25%	-18%	-14%	-12%

Future oil decline rates expected to moderate with wider-spacing development strategy

Note: Based on estimated YE-18 3-stream proved reserves, prepared by Ryder Scott

Oil, Natural Gas & Natural Gas Liquids Hedges

Hedge Product Summary	2Q-19 - 4Q-19	FY-20	FY-21
Oil total floor volume (Bbl)	6,875,000	7,539,600	912,500
Oil wtd-avg floor price ($/Bbl)	$60.42	$58.79	$45.00
Oil total floor volume w. deferred premium (Bbl)	*962,500*		
Oil wtd-avg deferred premium price ($/Bbl)	*$4.39*		
Nat gas total floor volume (MMBtu)	29,425,000	23,790,000	14,052,500
Nat gas wtd-avg floor price ($/MMBtu)	$3.09	$2.72	$2.63
NGL total floor volume (Bbl)	4,372,500	2,562,000	2,202,775

Oil	2Q-19 - 4Q-19	FY-20	FY-21
Puts			
Hedged volume (Bbl)	962,500	366,000	
Wtd-avg floor price ($/Bbl)	$55.00	$45.00	
Hedged Volume w. Deferred Premium (Bbl)	*962,500*		
Wtd-avg deferred premium price ($/Bbl)	*$4.39*		
Swaps			
Hedged volume (Bbl)	5,912,500	7,173,600	
Wtd-avg price ($/Bbl)	$61.31	$59.50	
Collars			
Hedged volume (Bbl)			912,500
Wtd-avg floor price ($/Bbl)			$45.00
Wtd-avg ceiling price ($/Bbl)			$71.00

Natural Gas - HH	2Q-19 - 4Q-19	FY-20	FY-21
Swaps			
Hedged volume (MMBtu)	29,425,000	23,790,000	14,052,500
Wtd-avg price ($/MMBtu)	$3.09	$2.72	$2.63

Natural Gas Liquids	2Q-19 - 4Q-19	FY-20	FY-21
Swaps - Ethane			
Hedged volume (Bbl)	1,787,500	366,000	912,500
Wtd-avg price ($/Bbl)	$14.22	$13.60	$12.01
Swaps - Propane			
Hedged volume (Bbl)	1,430,000	1,244,400	730,000
Wtd-avg price ($/Bbl)	$27.97	$26.58	$25.52
Swaps – Normal Butane			
Hedged volume (Bbl)	550,000	439,200	255,500
Wtd-avg price ($/Bbl)	$30.73	$28.69	$27.72
Swaps - Isobutane			
Hedged volume (Bbl)	137,500	109,800	67,525
Wtd-avg price ($/Bbl)	$31.08	$29.99	$28.79
Swaps - Natural Gasoline			
Hedged volume (Bbl)	467,500	402,600	237,250
Wtd-avg price ($/Bbl)	$45.80	$45.15	$44.31

Basis Swaps	2Q-19 - 4Q-19	FY-20	FY-21
Mid/Cush			
Hedged volume (Bbl)	2,392,000		
Wtd-avg price ($/Bbl)	-$3.23		
Hou/Mid			
Hedged volume (Bbl)	910,000		
Wtd-avg price ($/Bbl)	$7.30		
Waha/HH			
Hedged volume (MMBtu)	29,425,000	32,574,000	23,360,000
Wtd-avg price ($/MMBtu)	-$1.51	-$0.76	-$0.47

Note: Open positions as of 03/31/19, hedges executed through 04/30/19
See appendix slide 'Hedge Settlement Details' for settlement details
Hedged volumes with deferred premiums outlined above are included in provided totals and are therefore not additive

Hedge Settlement Details

Other than the oil basis swaps, the Company's oil derivatives are settled based on the month's arithmetic average of the daily settlement prices for the NYMEX index price for the first nearby month of the West Texas Intermediate Light Sweet Crude Oil Futures Contract.

The oil basis swaps are settled based on the differential between the basis swaps' fixed differential price as compared to the differential between the arithmetic average of each day's index prices for the first nearby month on the pricing dates in each calculation period with the index prices being either (i) the Argus Americas Crude's West Texas Intermediate ("WTI") Midland-weighted average and the Cushing-based NYMEX West Texas Intermediate Light Sweet Crude Oil Futures Contract, (ii) the Argus Americas Crude's WTI Midland-weighted average and the WTI formula basis or (iii) the Argus Americas Crude's WTI Houston-weighted average and the WTI Midland-weighted average.

The Company's NGL derivatives are settled based on the month's arithmetic average of the daily average of the high and low OPIS index prices for Mont Belvieu Purity Ethane, TET and Non-TET Propane, Non-TET Normal Butane, Non-TET Isobutane and Non-TET Natural Gasoline.

Other than the natural gas basis swaps, the Company's natural gas derivatives are settled based on the Inside FERC index price for West Texas WAHA or the NYMEX index price for Henry Hub for the calculation period. The natural gas basis swaps are settled based on the differential between the basis swaps' fixed differential price as compared to the differential between the Inside FERC index price for West Texas WAHA and the NYMEX index price for Henry Hub for the calculation period.

Supplemental Non-GAAP Financial Measure

Adjusted EBITDA

Adjusted EBITDA is a non-GAAP financial measure that we define as net income or loss plus adjustments for depletion, depreciation and amortization, non-cash stock-based compensation, net, accretion expense, mark-to-market on derivatives, premiums paid for derivatives, interest expense, gains or losses on disposal of assets and other non-recurring income and expenses. Adjusted EBITDA provides no information regarding a company's capital structure, borrowings, interest costs, capital expenditures, working capital movement or tax position. Adjusted EBITDA does not represent funds available for discretionary use because those funds are required for debt service, capital expenditures, working capital, income taxes, franchise taxes and other commitments and obligations. However, our management believes Adjusted EBITDA is useful to an investor in evaluating our operating performance because this measure:

- is widely used by investors in the oil and natural gas industry to measure a company's operating performance without regard to items excluded from the calculation of such term, which can vary substantially from company to company depending upon accounting methods, the book value of assets, capital structure and the method by which assets were acquired, among other factors;
- helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure from our operating structure; and
- is used by our management for various purposes, including as a measure of operating performance, in presentations to our board of directors and as a basis for strategic planning and forecasting.

There are significant limitations to the use of Adjusted EBITDA as a measure of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect our net income or loss, the lack of comparability of results of operations to different companies and the different methods of calculating Adjusted EBITDA reported by different companies. Our measurements of Adjusted EBITDA for financial reporting as compared to compliance under our debt agreements differ.

(in thousands, unaudited)	2Q-18	3Q-18	4Q-18	1Q-19
Net income (loss)	$33,452	$55,050	$149,573	$(9,491)
Plus:				
Income tax expense (benefit)	-	1,387	2,862	(96)
Depletion, depreciation and amortization	50,762	55,963	60,399	63,098
Non-cash stock-based compensation, net	10,676	8,733	7,648	7,406
Accretion expense	1,121	1,114	1,131	1,052
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	45,976	32,245	(112,195)	48,365
Settlements received (paid) for matured derivatives, net	181	(3,888)	12,033	102
Premiums paid for derivatives	(5,451)	(5,455)	(5,405)	(4,016)
Interest expense	14,424	14,845	15,117	15,547
Loss on disposal of assets, net	1,358	616	1,207	939
Adjusted EBITDA	$152,499	$160,610	$132,370	$122,906