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): July 31, 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**

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:

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

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

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

☐ 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 ☐

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 July 31, 2019, Laredo Petroleum, Inc. (the "Company") announced its financial and operating results for the quarter ended June 30, 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 August 1, 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 7258021. A replay of the call will be available through Thursday, August 8, 2019, by dialing 1.855.859.2056, and using conference code 7258021. 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 exhibits 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 July 31, 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 July 31, 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 July 31, 2019 announcing financial and operating results.
99.2	Presentation dated July 31, 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: July 31, 2019	By:	/s/ Michael T. Beyer
		Michael T. Beyer
		Senior Vice President and Chief Financial Officer

EXHIBIT 99.1

15 West 6th Street, Suite 900 · Tulsa, Oklahoma 74119 · (918) 513-4570 · Fax: (918) 513-4571
www.laredopetro.com

Laredo Petroleum Announces 2019 Second-Quarter Financial and Operating Results

Increases Oil Production Guidance, Maintains Capital Budget and Expects to Generate $30 Million In Free Cash Flow for Full-Year 2019

TULSA, OK - July 31, 2019 - Laredo Petroleum, Inc. (NYSE: LPI) ("Laredo" or "the Company") today announced its 2019 second-quarter results, reporting net income attributable to common stockholders of $173.4 million, or $0.75 per diluted share. Adjusted Net Income, a non-GAAP financial measure, for the second quarter of 2019 was $55.5 million, or $0.24 per diluted share. Adjusted EBITDA, a non-GAAP financial measure, for the second quarter of 2019 was $153.2 million. Please see supplemental financial information at the end of this news release for reconciliations of non-GAAP financial measures.

2019 Second-Quarter Highlights

- Completed the widely-spaced Yellow Rose package, which is outperforming a directly offset tightly-spaced package by 30% based on cumulative oil production per foot
- Produced a Company record 30,447 barrels of oil per day ("BOPD"), exceeding oil production guidance by 7% or almost 2,000 BOPD
- Reduced amount outstanding on the Company's credit facility by $35.0 million, lowering Net Debt to Adjusted EBITDA to 1.7 times[a]
- Received net cash payments of $15.8 million on settlements of derivatives as the Company's hedges mitigated the impact of commodity price declines
- Reduced controllable cash costs of combined unit lease operating expenses ("LOE") and unit cash general and administrative expenses ("G&A") to $4.69 per barrel of oil equivalent ("BOE"), a 23% decrease from full-year 2018 results of $6.07 per BOE

"The second quarter of 2019 fully demonstrated the results of the strategic transformation Laredo began late last year," stated Randy A. Foutch, Chairman and Chief Executive Officer. "Well productivity dramatically improved from 2018 as we widened spacing, unit cash G&A decreased 36% from full-year 2018 after we reduced personnel expenses, we paid down $35 million of debt as we generated free cash flow during the quarter, and now we expect to generate $30 million in free cash flow for full-year 2019."

"We believe there is still room to improve on these results," explained Jason Pigott, President. "We are refining our development focus to reduce the risk of vertical interference in our Upper/Middle Wolfcamp drilling and we are returning to areas of the Cline where economics have become competitive as costs have come down. High-grading inventory and further reducing costs to improve returns facilitate our top priorities of measured oil growth with free cash flow generation and replenishing our high-quality inventory through bolt-on transactions."

Guidance Update

In the first half of 2019, Laredo has surpassed the Company's production and cash flow generation expectations and is in line with capital expenditure expectations. Accordingly, full-year 2019 oil and total production guidance and free cash flow expectations are being increased. Laredo now expects oil production for full-year 2019 to be flat compared to full-year 2018, an increase from previous guidance of down 2%. Total production is now expected to grow 14% versus previous guidance of 11% growth. These increases in production expectations are anticipated to drive free cash flow generation[b] of $30 million for full-year 2019 while operating within our $465 million capital budget, excluding non-budgeted acquisitions.

The Company's decision to widen development spacing to improve well productivity, combined with sustainable operational efficiency gains that have shortened cycle times, is driving these increased production expectations. Increasing production assumptions, coupled with Laredo's robust 2019 commodity hedges that mitigate the impact of declining commodity prices, underpins Laredo's confidence in these free cash flow projections.

E&P Update

During the second quarter of 2019, Laredo completed 12 gross (11.5 net) horizontal wells with an average lateral length of approximately 11,600 feet. These 12 wells were developed in two packages, both utilizing the Company's wider-spaced development plan. The Yellow Rose package, an eight-well co-development package, began flowback at the end of April. After more than 100 days of production, oil productivity per lateral foot is outperforming an offset package of tighter-spaced wells completed in 2018 by more than 30%, reinforcing the Company's confidence in its Upper/Middle Wolfcamp type curve.

Oil and total production both exceeded second-quarter 2019 guidance, driven by the performance of the Yellow Rose package and wells being put on production earlier than anticipated due to reduced cycle times. Second-quarter 2019 oil production was 30,447 BOPD and total production was 82,259 BOE per day, exceeding Company-issued guidance by 7% and 5%, respectively.

In the third quarter of 2019, Laredo expects to complete 11 gross (11 net) widely-spaced horizontal wells with an average completed lateral length of approximately 10,100 feet. The first package is a four-well, single zone development package in the Middle Wolfcamp, infilling below a previous Upper Wolfcamp development package. The second is a seven-well, Middle Wolfcamp co-development package. These wells will further the Company's successful transition to wider-spacing development and will provide additional valuable information on optimal vertical spacing.

Laredo continues to sharpen its focus on high-grading development to optimize returns and minimize spacing risk. One important refinement is the Company's evolving approach to Upper/Middle Wolfcamp development. Using both proprietary and third-party vertical spacing data to quantify productivity impacts of the vertical distances between horizontal wells, the Company's Upper/Middle Wolfcamp co-development strategy will now target three landing points rather than four. Laredo expects this approach to reduce risks associated with vertical interference and increase the certainty of productivity expectations.

Additionally, the Company is planning to return to regions of higher productivity in the Cline formation that are expected to generate returns commensurate with Upper/Middle Wolfcamp targets as drilling and completions costs have decreased. These assumptions have been incorporated into a new Cline type curve for 10,000-foot lateral horizontal wells in these areas. Total production expectations for the new regional Cline type curve are 1.0 MMBOE for the life of the well, comprised of approximately 40% oil, with more than 60% of expected oil production recovered in the first five years of the life of the well. The Company expects to begin incorporating some of these Cline locations into its 2020 development program.

Laredo's successful shift to wider-spaced development is expected to drive productivity improvements versus tighter-spaced development, as demonstrated by the Yellow Rose package. High-grading inventory, prioritizing development based on the highest rate of return targets and replenishing inventory through targeted bolt-on leasing and acquisitions are expected to sustain these improvements and drive the Company's long-term goals of moderate oil production growth and free cash flow generation.

Laredo Midstream Services

Laredo's investments in field infrastructure through its wholly-owned Laredo Midstream Services LLC ("LMS") subsidiary drive both environmental and financial benefits for the Company. Through the first half of 2019, oil and water gathering pipelines owned or contracted by LMS gathered more than 18,000,000 barrels of oil and water, eliminating the need for more than 130,000 truckloads within Laredo's leasehold and producing a net financial benefit to the Company of approximately $18 million. LMS' water recycling plants processed more than 3,100,000 barrels of water in the first six months of 2019 and Laredo utilized 5,900,000 barrels of recycled water in completions activities over the same period, reducing capital expenditures and LOE by a combined $2.2 million.

The Company continues to improve upon its peer-leading unit LOE, driven by the field infrastructure providing a substantial and sustainable financial benefit. Unit LOE in the first half of 2019 was $3.24 per BOE, a 14% reduction from the first half of 2018. Laredo estimates field infrastructure benefits reduced unit LOE for the first half of 2019 by $0.57 per BOE.

2019 Capital Program

During the second quarter of 2019, Laredo invested $116 million in drilling and completions activities. Other expenditures incurred during the quarter included $4 million in land-related expenditures and data acquisition, $8 million in infrastructure, including LMS investments, and $4 million in other capitalized costs. Additionally, the Company completed property acquisitions for $3 million that were not previously budgeted.

Total costs incurred of $296 million in the first half of 2019, excluding non-budgeted acquisitions, put the Company on pace to deliver on its plan to complete 52 wells within the $465 million capital budget and deliver $30 million in free cash flow for full-year 2019, excluding non-budgeted acquisitions.

Liquidity

At June 30, 2019, the Company had outstanding borrowings of $235 million on its $1.1 billion senior secured credit facility, resulting in available capacity, after reductions for outstanding letters of credit, of $850 million. Including cash and cash equivalents of $56 million, total liquidity was $906 million.

Subsequent to the end of the second quarter of 2019, Laredo paid down an additional $20 million on its credit facility, resulting in outstanding borrowings of $215 million. Including cash and cash equivalents at July 31, 2019 of $40 million and after reductions for outstanding letters of credit, total liquidity was $910 million.

To date, the Company has repaid $55 million of the $80 million borrowed in the first quarter of 2019 and expects to fully repay the $80 million by the end of the year.

Commodity Derivatives

Laredo has hedged approximately 95% of anticipated oil production at a weighted-average floor price of $60.42 per barrel for the remainder of 2019 and approximately 75% of anticipated oil production at a weighted-average floor price of $58.79 for full-year 2020. Additionally, Laredo has hedged approximately 70% of anticipated natural gas production and 65% of anticipated natural gas liquids ("NGL") production for the remainder of 2019 and approximately 45% of anticipated natural gas production and approximately 30% of anticipated NGL production for full-year 2020.

Additional 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 14% and oil production guidance to flat as compared to full-year 2018. The table below reflects the Company's guidance for the third quarter of 2019.

	3Q-2019E
Total production (MBOE/d)	79.0
Oil production (MBO/d)	27.3
Average sales price realizations (without derivatives):	
Oil (% of WTI)	97%
NGL (% of WTI)	15%
Natural gas (% of Henry Hub)	20%
Selected average costs & expenses:	
Lease operating expenses ($/BOE)	$3.35
Production and ad valorem taxes (% of oil, NGL and natural gas revenues)	6.50%
Transportation and marketing expenses ($/BOE)	$0.70
Midstream service expenses ($/BOE)	$0.15
General and administrative:	
Cash ($/BOE)	$1.70
Non-cash stock-based compensation, net ($/BOE)	$0.65
Depletion, depreciation and amortization ($/BOE)	$9.00

Conference Call Details

On Thursday, August 1, 2019, at 7:30 a.m. CT, Laredo will host a conference call to discuss its second-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 7258021, approximately 10 minutes prior to the scheduled conference time. A telephonic replay will be available approximately two hours after the call on August 1, 2019 through Thursday, August 8, 2019. Participants may access this replay by dialing 855.859.2056, using conference code 7258021.

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. This press release and any accompanying disclosures may include or reference certain forward-looking, non-GAAP financial measures, such as free cash flow, and certain related estimates regarding future performance, results and financial position. 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 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

	Three months ended June 30,		Six months ended June 30,	
	2019	2018	2019	2018
	(unaudited)		(unaudited)	
Revenues:				
Oil, NGL and natural gas sales	$ 183,863	$ 208,561	$ 357,239	$ 405,995
Midstream service revenues	2,610	1,976	5,493	4,335
Sales of purchased oil	30,170	140,509	62,858	200,412
Total revenues	216,643	351,046	425,590	610,742
Costs and expenses:				
Lease operating expenses	23,632	22,642	46,241	44,593
Production and ad valorem taxes	11,328	12,405	18,547	24,217
Transportation and marketing expenses	4,891	1,534	9,650	1,534
Midstream service expenses	607	403	2,210	1,096
Costs of purchased oil	30,172	140,578	62,863	201,242
General and administrative	11,056	26,834	32,575	51,559
Restructuring expenses	10,406	—	10,406	—
Depletion, depreciation and amortization	65,703	50,762	128,801	96,315
Other operating expenses	1,020	1,121	2,072	2,227
Total costs and expenses	158,815	256,279	313,365	422,783
Operating income	57,828	94,767	112,225	187,959
Non-operating income (expense):				
Gain (loss) on derivatives, net	88,394	(45,976)	40,029	(36,966)
Interest expense	(15,765)	(14,424)	(31,312)	(27,942)
Litigation settlement	42,500	—	42,500	—
Other, net	2,176	(915)	2,104	(3,079)
Non-operating income (expense), net	117,305	(61,315)	53,321	(67,987)
Income before income taxes	175,133	33,452	165,546	119,972
Income tax expense:				
Deferred	(1,751)	—	(1,655)	—
Total income tax expense	(1,751)	—	(1,655)	—
Net income	$ 173,382	$ 33,452	$ 163,891	$ 119,972
Net income per common share:				
Basic	$ 0.75	$ 0.14	$ 0.71	$ 0.51
Diluted	$ 0.75	$ 0.14	$ 0.71	$ 0.51
Weighted-average common shares outstanding:				
Basic	231,406	230,933	230,943	234,561
Diluted	231,557	231,706	231,725	235,501

Laredo Petroleum, Inc.
Condensed consolidated statements of cash flows

	Three months ended June 30,		Six months ended June 30,	
	2019	2018	2019	2018
	(unaudited)		(unaudited)	
Cash flows from operating activities:				
Net income	$ 173,382	$ 33,452	$ 163,891	$ 119,972
Adjustments to reconcile net income to net cash provided by operating activities:				
Deferred income tax expense	1,751	—	1,655	—
Depletion, depreciation and amortization	65,703	50,762	128,801	96,315
Non-cash stock-based compensation, net	(423)	10,676	6,983	20,015
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	(88,394)	45,976	(40,029)	36,966
Settlements received (paid) for matured derivatives, net	23,480	181	23,582	(2,055)
Settlements paid for early terminations of derivatives, net	(5,409)	—	(5,409)	—
Premiums paid for derivatives	(2,233)	(5,451)	(6,249)	(9,475)
Other, net	4,413	3,636	12,189	8,944
Cash flows from operating activities before changes in assets and liabilities	172,270	139,232	285,414	270,682
Decrease (increase) in current assets and liabilities, net	9,628	(24,867)	(27,122)	(9,372)
Decrease in noncurrent assets and liabilities, net	1,913	1,765	2,977	1,291
Net cash provided by operating activities	183,811	116,130	261,269	262,601
Cash flows from investing activities:				
Acquisitions of oil and natural gas properties	(2,880)	(16,340)	(2,880)	(16,340)
Capital expenditures:				
Oil and natural gas properties	(131,887)	(146,509)	(284,616)	(341,534)
Midstream service assets	(3,187)	(1,843)	(5,449)	(5,205)
Other fixed assets	(460)	(1,002)	(965)	(4,965)
Proceeds from disposition of assets, net of selling costs	893	11,296	936	13,972
Net cash used in investing activities	(137,521)	(154,398)	(292,974)	(354,072)
Cash flows from financing activities:				
Borrowings on Senior Secured Credit Facility	—	55,000	80,000	110,000
Payments on Senior Secured Credit Facility	(35,000)	—	(35,000)	—
Share repurchases	—	(33,504)	—	(87,218)
Other, net	(34)	(2,513)	(2,646)	(6,866)
Net cash (used in) provided by financing activities	(35,034)	18,983	42,354	15,916
Net increase (decrease) in cash and cash equivalents	11,256	(19,285)	10,649	(75,555)
Cash and cash equivalents, beginning of period	44,544	55,889	45,151	112,159
Cash and cash equivalents, end of period	$ 55,800	$ 36,604	$ 55,800	$ 36,604

Laredo Petroleum, Inc.
Selected operating data

	Three months ended June 30,				Six months ended June 30,			
	2019		2018		2019		2018	
	(unaudited)				(unaudited)			
Sales volumes:								
Oil (MBbl)		2,771		2,514		5,305		4,953
NGL (MBbl)		2,200		1,778		4,299		3,341
Natural gas (MMcf)		15,092		10,947		27,941		21,120
Oil equivalents (MBOE)[1][2]		7,485		6,116		14,260		11,814
Average daily sales volumes (BOE/D)[2]		82,259		67,206		78,787		65,270
% Oil[2]		37%		41%		37%		42%
Average sales prices[2]:								
Oil, without derivatives ($/Bbl)[3]	$	57.76	$	63.26	$	54.52	$	62.58
NGL, without derivatives ($/Bbl)[3]	$	10.09	$	20.71	$	12.66	$	19.51
Natural gas, without derivatives ($/Mcf)[3]	$	0.11	$	1.16	$	0.49	$	1.46
Average sales price, without derivatives ($/BOE)[3]	$	24.56	$	34.10	$	25.05	$	34.37
Oil, with derivatives ($/Bbl)[4]	$	56.65	$	58.71	$	52.36	$	58.62
NGL, with derivatives ($/Bbl)[4]	$	12.82	$	20.07	$	14.04	$	19.15
Natural gas, with derivatives ($/Mcf)[4]	$	1.17	$	1.72	$	1.14	$	1.78
Average sales price, with derivatives ($/BOE)[4]	$	27.09	$	33.04	$	25.94	$	33.18
Selected average costs and expenses per BOE sold[2]:								
Lease operating expenses	$	3.16	$	3.70	$	3.24	$	3.78
Production and ad valorem taxes		1.51		2.03		1.30		2.05
Transportation and marketing expenses		0.65		0.25		0.68		0.13
Midstream service expenses		0.08		0.07		0.15		0.09
General and administrative:								
Cash		1.53		2.64		1.79		2.67
Non-cash stock-based compensation, net[5]		(0.06)		1.75		0.49		1.69
Depletion, depreciation and amortization		8.78		8.30		9.03		8.15
Total selected costs and expenses	$	15.65	$	18.74	$	16.68	$	18.56
Average cash margins per BOE sold[2][6]:								
Without derivatives	$	17.63	$	25.41	$	17.89	$	25.65
With derivatives	$	20.16	$	24.35	$	18.78	$	24.46

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

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

(3) 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) For the three and six months ended June 30, 2019, non-cash stock-based compensation, net, excluding forfeitures related to our April 2019 organizational restructuring, on a per BOE sold basis was $0.75 and $0.91, respectively.

(6) On a per BOE basis, average cash margins are calculated as average sales 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.

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 evaluated property acquisition costs and development costs, for the periods presented:

	Three months ended June 30,		Six months ended June 30,	
(in thousands)	**2019**	**2018**	**2019**	**2018**
	(unaudited)		(unaudited)	
Property acquisition costs[1]:				
Evaluated	$ —	$ 13,847	$ —	$ 13,847
Unevaluated	2,880	2,790	2,880	2,790
Exploration costs	5,116	5,108	12,621	11,245
Development costs	123,664	178,796	276,381	327,834
Total costs incurred	$ 131,660	$ 200,541	$ 291,882	$ 355,716

____

(1) See Note 3.a in the second-quarter 2018 Quarterly Report for discussion of the Company's acquisitions of evaluated and unevaluated oil and natural gas properties during the three months ended June 30, 2018.

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, Adjusted EBITDA, Net Debt to Adjusted EBITDA and Projected Free Cash Flow, 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.

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

	Three months ended June 30,		Six months ended June 30,	
(in thousands, except per share data)	**2019**	**2018**	**2019**	**2018**
	(unaudited)		(unaudited)	
Income before income taxes	$ 175,133	$ 33,452	$ 165,546	$ 119,972
Plus:				
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	(88,394)	45,976	(40,029)	36,966
Settlements received (paid) for matured derivatives, net	23,480	181	23,582	(2,055)
Settlements paid for early terminations of derivatives, net	(5,409)	—	(5,409)	—
Premiums paid for derivatives	(2,233)	(5,451)	(6,249)	(9,475)
Restructuring expenses	10,406	—	10,406	—
Litigation settlement	(42,500)	—	(42,500)	—
Loss on disposal of assets, net	670	1,358	1,609	3,975
Adjusted income before adjusted income tax expense	71,153	75,516	106,956	149,383
Adjusted income tax expense[(1)]	(15,654)	(16,614)	(23,530)	(32,864)
Adjusted Net Income	$ 55,499	$ 58,902	$ 83,426	$ 116,519
Net income per common share:				
Basic	$ 0.75	$ 0.14	$ 0.71	$ 0.51
Diluted	$ 0.75	$ 0.14	$ 0.71	$ 0.51
Adjusted Net Income per common share:				
Basic	$ 0.24	$ 0.26	$ 0.36	$ 0.50
Diluted	$ 0.24	$ 0.25	$ 0.36	$ 0.49
Weighted-average common shares outstanding:				
Basic	231,406	230,933	230,943	234,561
Diluted	231,557	231,706	231,725	235,501

____

(1) Adjusted income tax expense is calculated by applying a statutory tax rate of 22% for each of the periods ended June 30, 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 (GAAP) to Adjusted EBITDA (non-GAAP):

	Three months ended June 30,		Six months ended June 30,	
(in thousands)	**2019**	**2018**	**2019**	**2018**
	(unaudited)		(unaudited)	
Net income	$ 173,382	$ 33,452	$ 163,891	$ 119,972
Plus:				
Deferred income tax expense	1,751	—	1,655	—
Depletion, depreciation and amortization	65,703	50,762	128,801	96,315
Non-cash stock-based compensation, net	(423)	10,676	6,983	20,015
Restructuring expenses	10,406	—	10,406	—
Accretion expense	1,020	1,121	2,072	2,227
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	(88,394)	45,976	(40,029)	36,966
Settlements received (paid) for matured derivatives, net	23,480	181	23,582	(2,055)
Settlements paid for early terminations of derivatives, net	(5,409)	—	(5,409)	—
Premiums paid for derivatives	(2,233)	(5,451)	(6,249)	(9,475)
Interest expense	15,765	14,424	31,312	27,942
Litigation settlement	(42,500)	—	(42,500)	—
Loss on disposal of assets, net	670	1,358	1,609	3,975
Adjusted EBITDA	$ 153,218	$ 152,499	$ 276,124	$ 295,882

[a] Net Debt to Adjusted EBITDA

Net debt to Adjusted EBITDA is calculated as net debt as of June 30, 2019 divided by trailing twelve-month Adjusted EBITDA ending June 30, 2019 of $569 million. Net debt as of June 30, 2019 was $979 million, calculated as the face value of debt of $1.035 billion reduced by cash and cash equivalents of $56 million. See above for a definition of Adjusted EBITDA.

[b] Projected Free Cash Flow

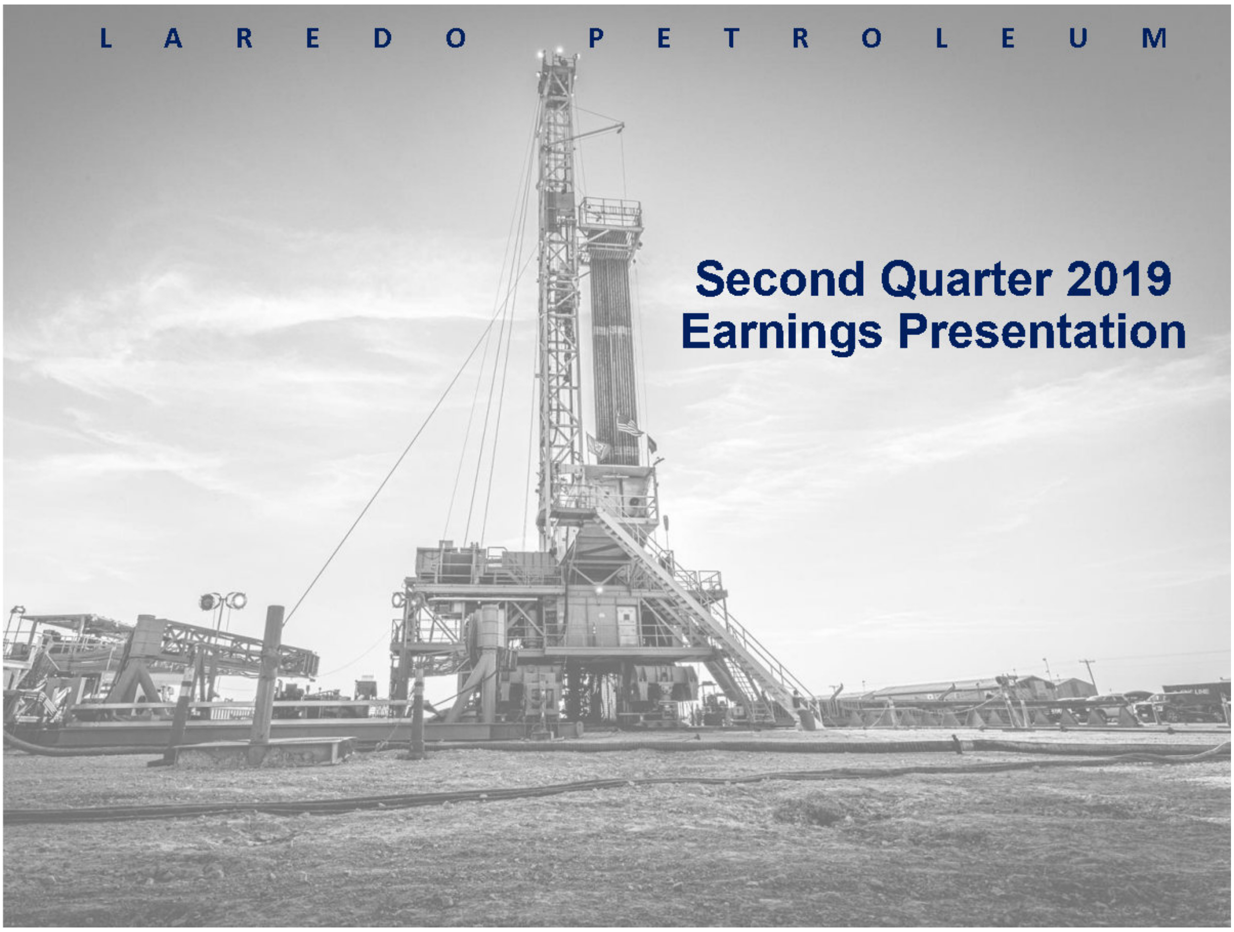
Projected free cash flow is calculated as estimated full-year 2019 cash flows from operating activities before changes in assets and liabilities, less cash and non-cash capital investments made during the period, excluding non-budgeted acquisitions.

Management believes this is useful to investors in evaluating the operating trends in its business due to production, commodity prices, operating costs and other related factors.

# # #

Contacts:
Ron Hagood: (918) 858-5504 - RHagood@laredopetro.com

EXHIBIT 99.2


L A R E D O P E T R O L E U M
Second 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"). 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 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, 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, cash flow and free cash flow. 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, cash flow and free cash flow 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.

All amounts, dollars and percentages presented in this presentation are rounded and therefore approximate.

2019: A Transformational Year

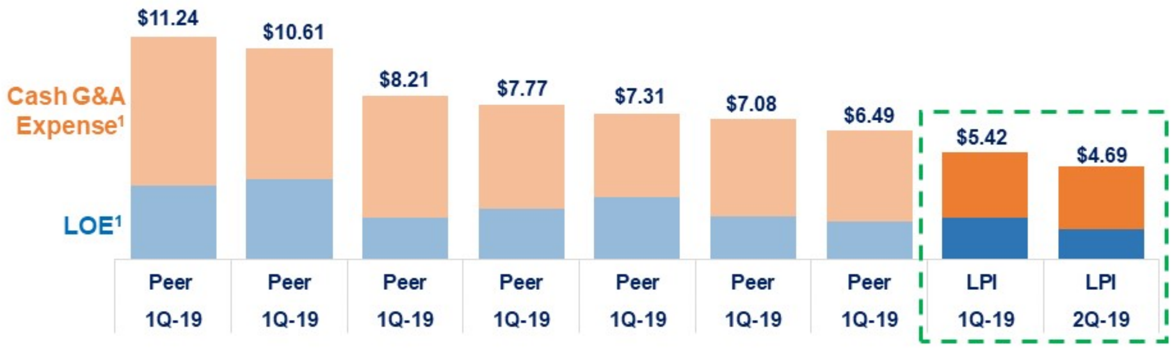
Optimized operations	$700,000/well savings since YE-18
	Moved to wider-spaced development
Aligned personnel costs with activity	$30 MM/year annualized cash & non-cash expenses & capital savings expected
	Reduced officer positions by ~40%
Reconstructed Senior Management Team	New President, COO, CFO & GC

Execution of strategic initiatives are driving free cash flow generation in 2019E

Surpassing Guidance on Production & Expenses

2Q-19A Select Results

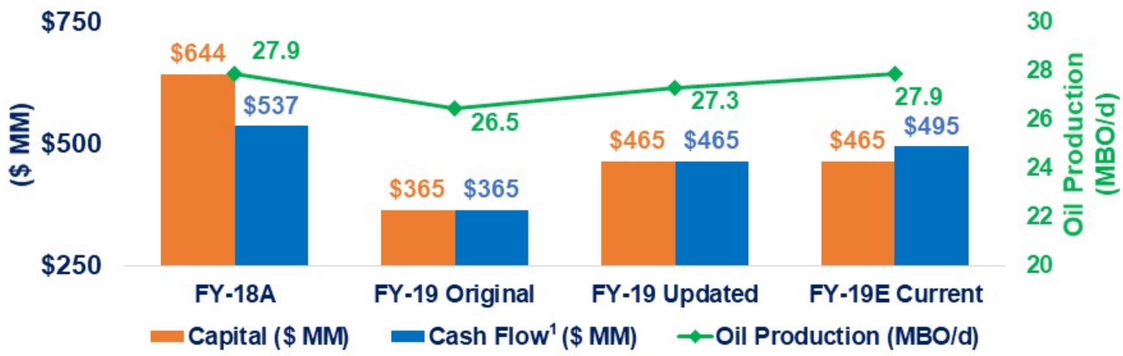
Production	Controllable Cash Costs
Oil Production 30.4 MBO/d — 7% Beat vs guidance	**Lease Operating Expense** $3.16/BOE — 4% Beat vs guidance
Total Production 82.3 MBOE/d — 5% Beat vs guidance	**G&A Cash Expense** $1.53/BOE — 24% Beat vs guidance



44% lower 2Q-19A controllable cash costs versus 1Q-19A peer average

[1]Representative of unit expenses
Note: Peers include - CDEV, CPE, CRZO, JAG, MTDR, QEP, SM

Higher FY-19 Oil Guidance, Maintaining Capex & Generating Free Cash



	FY-18A	FY-19 Original	FY-19 Updated	FY-19E Current
LPI Well Type	Tightly-Spaced	1.3 MMBOE UWC/MWC Type Curve	1.3 MMBOE UWC/MWC Type Curve	1.3 MMBOE UWC/MWC Type Curve
Well Cost[2] ($ MM)	$7.7	$7.5	$7.0	$7.0
WTI Price ($/BO)	$65	$54	$58	$56
Hedged Price[3] ($/BO)	$47.42	$47.91	$60.42	$60.42
Well Spacing	660'	1,320'	1,320'	1,320'

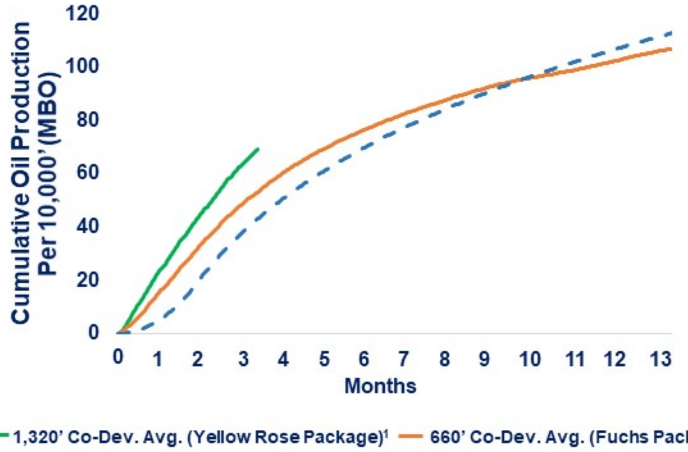
Expect to generate $30 MM of free cash flow[1] in 2019

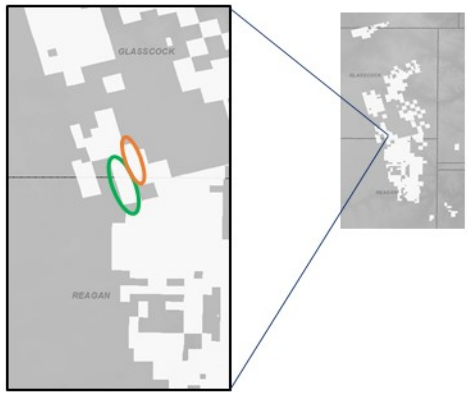
[1]See Appendix for a reconciliation of net cash provided by operating activities to cash flow and free cash flow
[2]Well costs indicative of a 10,000' UWC/MWC utilizing a 2-well pad
[3]Reflective of the weighted-average WTI floor price in place for the period
Note: Capital excludes non-budgeted acquisitions & includes cash & non-cash capital

LAREDO PETROLEUM

Wider Spacing Improves Oil Productivity

Initial Yellow Rose package results confirm that completed wider spacing shift is improving productivity and returns versus 2018





- **Wider-spaced package is outperforming offset tighter-spaced package by 30%**
- **Performance confirms Company's UWC/MWC 1.3 MMBOE (400 MBO) type curve**

[1]Includes an average of the Yellow Rose package (8 wells) cumulative oil production, normalized to a 10,000' lateral
[2]Includes an average of the Fuchs package (11 wells) cumulative oil production, normalized to a 10,000' lateral
Note: UWC/MWC 1.3 MMBOE type curve (400 MBO) representative of a 10,000' well, utilizing a 1.2 b-factor

Wider Spacing & Reduced Well Costs Improve IRR

Per Well Costs & Drilling ROR

	FY-18A	FY-19 Original	FY-19E Current
LPI Well Type	Tightly-Spaced	1.3 MMBOE Type Curve	1.3 MMBOE Type Curve
Well Cost[1] ($ MM)	$7.7	$7.5	$7.0
WTI Price ($/BO)	$65	$54	$56
Well Spacing	660’	1,320’	1,320’

Strategic improvements versus 2018 development plan are driving higher returns

LAREDO PETROLEUM

[1]Well costs indicative of a 10,000’ UWC/MWC utilizing a 2-well pad

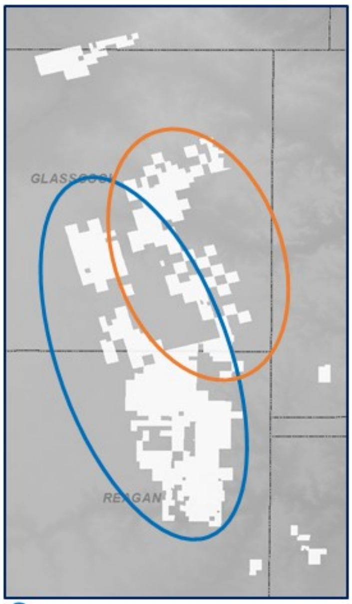
High-Grading Inventory to Reduce Risk & Maximize Returns

UWC/MWC Combined		
Wells per DSU	Drill Pattern	Inventory[1]
8 - 12	● ● ● ● ● ● ● ● ● ● ● ●	350 - 500

Regional Cline		
Wells per DSU	Drill Pattern	Inventory[1]
4	● ● ● ●	140 - 160

● 1,320' single zone development

● 1,320' co-development



UWC/MWC Inventory

Regional Cline Inventory

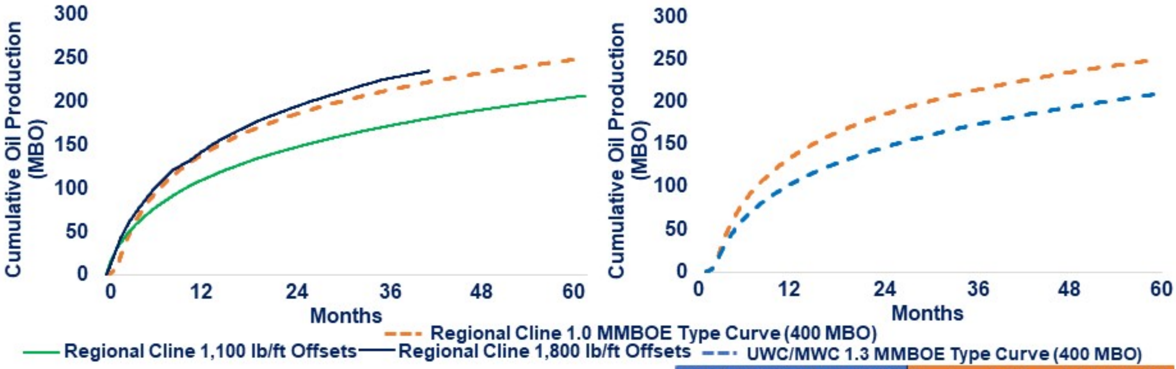
Continually optimizing inventory to incorporate current spacing and cost assumptions

[1]Inventory expected to average oil type curve productivity

Note: Drilling spacing unit (DSU)

Cline Reintroduced As Primary Target Due to Cost Savings

Regional Cline wells exceed near-term UWC/MWC oil productivity



- **Decrease in well costs from $8.9 MM to $8.2 MM yield returns stronger than UWC/MWC type curve wells**
- **Data used from 32 regional Cline wells to develop a region-specific curve**
- **Completions optimization shown to significantly improve productivity**

	UWC/MWC 1.3 MMBOE Type Curve (400 MBO)			Regional Cline 1.0 MMBOE Type Curve (400 MBO)		
Year	Oil (MBO)	Total (MBOE)	Oil Cut (%)	Oil (MBO)	Total (MBOE)	Oil Cut (%)
1	107	213	50%	139	295	47%
2	41	130	32%	48	128	37%
3	26	84	31%	28	76	37%
4	20	64	31%	20	55	37%
5	16	53	30%	16	43	37%
5-Year Cum. Prod.	210	544	39%	250	596	42%
Life of Well	400	1,300	30%	400	1,000	40%

Note: Regional Cline 1.0 MMBOE type curve (400 MBO) representative of a 10,000' well, utilizing a 1.0 b-factor; assumed well cost of $8.2 MM
UWC/MWC 1.3 MMBOE type curve (400 MBO) representative of a 10,000' well, utilizing a 1.2 b-factor; assumed well cost of $7.0 MM
Table may not foot due to rounding

LAREDO PETROLEUM

2019 Product Hedges Protect Cash Flow

% Hedged[1]	Oil: 95%	Natural Gas: 70%

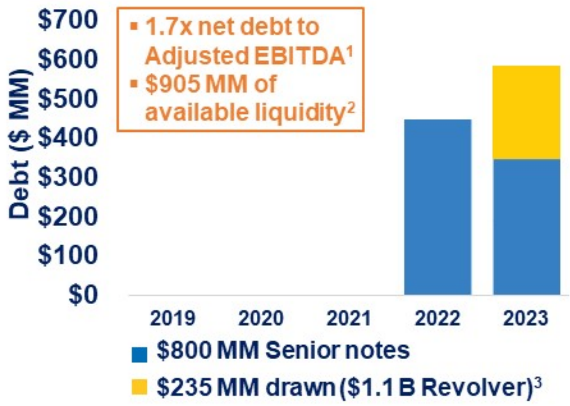
% Hedged[1]	Ethane: 65%	Propane: 65%	N. Butane: 70%	I. Butane: 70%	N. Gasoline: 65%

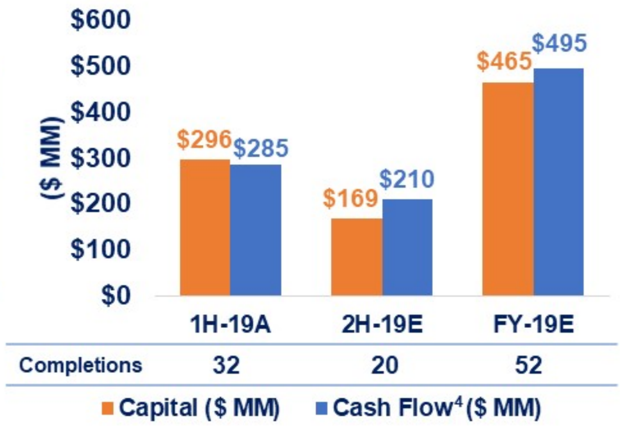
Hedges in place significantly reduce the impact of commodity price fluctuations and help ensure cash flow projections

LAREDO PETROLEUM

[1]Percentages reflective of hedged volumes as a percent of forecasted production; strip as of 7/22/19; LPI is representative of LPI's 2H-19 weighted-average floor price

Stronger than Expected Cash Flow Generation Used to Pay Down Debt





Utilized $35 MM of free cash flow[4] in 2Q-19 to reduce outstanding borrowings on the revolver

[1]As of 2Q-19. See Appendix for the calculation of net debt to Adjusted EBITDA and a reconciliation of Net Income to Adjusted EBITDA
[2]As of 2Q-19. See Appendix for the calculation of liquidity
[3]As of 6/30/19, per the 4/30/19 semi-annual redetermination of $1.1 B aggregate elected commitment in place under Fifth Amended and Restated Senior Secured Credit Facility
[4]See Appendix for a reconciliation of net cash provided by operating activities to cash flow and free cash flow
Note: Capital excludes non-budgeted acquisitions & includes cash & non-cash capital; FY-19E based on $56/BO WTI & $2.60/MMBtu HH

LAREDO PETROLEUM

Redefined Development Strategy Drives Free Cash Flow Generation

- High-Grading Inventory
- Optimizing Spacing
- Controlling Costs
- Driving Operational Efficiencies
- Ongoing Financial Risk Management

- Free Cash Flow
- Improved Returns
- Measured Oil Growth

LAREDO PETROLEUM

APPENDIX

3Q-19 Guidance

Production	
Total production (MBOE/d)	79.0
Oil production (MBbl/d)	27.3

Average sales price realizations: *(excluding derivatives)*	
Oil (% of WTI)	97%
NGL (% of WTI)	15%
Natural gas (% of Henry Hub)	20%

Operating costs & expenses ($/BOE):	
Lease operating expenses	$3.35
Production and ad valorem taxes *(% of oil, NGL and natural gas revenues)*	6.50%
Transportation and marketing expenses	$0.70
Midstream service expenses	$0.15
General and administrative expenses:	
Cash	$1.70
Non-cash stock-based compensation, net	$0.65
Depletion, depreciation and amortization	$9.00

Oil, Natural Gas & Natural Gas Liquids Hedges

Hedge Product Summary	3Q-19 - 4Q-19	FY-20	FY-21
Oil total floor volume (Bbl)	4,600,000	7,539,600	912,500
Oil wtd-avg floor price ($/Bbl)	$60.42	$58.79	$45.00
Oil total floor volume w. deferred premium (Bbl)	*644,000*		
Oil wtd-avg deferred premium price ($/Bbl)	*$4.39*		
Nat gas total floor volume (MMBtu)	19,688,000	23,790,000	14,052,500
Nat gas wtd-avg floor price ($/MMBtu)	$3.09	$2.72	$2.63
NGL total floor volume (Bbl)	2,925,600	2,562,000	2,202,775

Oil	3Q-19 - 4Q-19	FY-20	FY-21
Puts			
Hedged volume (Bbl)	644,000	366,000	
Wtd-avg floor price ($/Bbl)	$55.00	$45.00	
Hedged Volume w. Deferred Premium (Bbl)	*644,000*		
Wtd-avg deferred premium price ($/Bbl)	*$4.39*		
Swaps			
Hedged volume (Bbl)	3,956,000	7,173,600	
Wtd-avg price ($/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	3Q-19 - 4Q-19	FY-20	FY-21
Swaps			
Hedged volume (MMBtu)	19,688,000	23,790,000	14,052,500
Wtd-avg price ($/MMBtu)	$3.09	$2.72	$2.63

Natural Gas Liquids	3Q-19 - 4Q-19	FY-20	FY-21
Swaps - Ethane			
Hedged volume (Bbl)	1,196,000	366,000	912,500
Wtd-avg price ($/Bbl)	$14.22	$13.60	$12.01
Swaps - Propane			
Hedged volume (Bbl)	956,800	1,244,400	730,000
Wtd-avg price ($/Bbl)	$27.97	$26.58	$25.52
Swaps – Normal Butane			
Hedged volume (Bbl)	368,000	439,200	255,500
Wtd-avg price ($/Bbl)	$30.73	$28.69	$27.72
Swaps - Isobutane			
Hedged volume (Bbl)	92,000	109,800	67,525
Wtd-avg price ($/Bbl)	$31.08	$29.99	$28.79
Swaps - Natural Gasoline			
Hedged volume (Bbl)	312,800	402,600	237,250
Wtd-avg price ($/Bbl)	$45.80	$45.15	$44.31

Basis Swaps	3Q-19 - 4Q-19	FY-20	FY-21
Mid/Cush			
Hedged volume (Bbl)	2,392,000		
Wtd-avg price ($/Bbl)	-$3.23		
Waha/HH			
Hedged volume (MMBtu)	19,688,000	32,574,000	23,360,000
Wtd-avg price ($/MMBtu)	-$1.51	-$0.76	-$0.47

LAREDO PETROLEUM

Note: Open positions as of 6/30/19, hedges executed through 07/30/19
Hedged volumes with deferred premiums outlined above are included in provided totals and are therefore not additive

Supplemental Financial Calculations

Net debt to Adjusted EBITDA

Net debt to Adjusted EBITDA is calculated as net debt as of June 30, 2019 divided by trailing twelve-month Adjusted EBITDA ending June 30, 2019 of $569 million. Net debt as of June 30, 2019 was $979 million, calculated as the face value of debt of $1.035 billion reduced by cash and cash equivalents of $56 million.

See next slide for a reconciliation of Net Income to Adjusted EBITDA.

Liquidity

At June 30, 2019, the Company had outstanding borrowings of $235 million on its $1.1 billion senior secured credit facility, resulting in available capacity, after reductions for outstanding letters of credit, of $850 million. Including cash and cash equivalents of $56 million, total liquidity was $906 million.

Subsequent to the end of the second quarter of 2019, Laredo paid down an additional $20 million on its credit facility, resulting in outstanding borrowings of $215 million. Including cash and equivalents at July 31, 2019 of $40 million and after reductions for outstanding letters of credit, total liquidity was $910 million.

Supplemental Non-GAAP Financial Measure

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 (GAAP) to Adjusted EBITDA (non-GAAP):

(in thousands, unaudited)	3Q-18	4Q-18	1Q-19	2Q-19
Net income (loss)	$55,050	$149,573	$(9,491)	$173,382
Plus:				
Income tax expense (benefit)	1,387	2,862	(96)	1,751
Depletion, depreciation and amortization	55,963	60,399	63,098	65,703
Non-cash stock-based compensation, net	8,733	7,648	7,406	(423)
Restructuring expense	-	-	-	10,406
Accretion expense	1,114	1,131	1,052	1,020
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	32,245	(112,195)	48,365	(88,394)
Settlements received (paid) for matured derivatives, net	(3,888)	12,033	102	23,480
Settlements paid for early termination of derivatives, net	-	-	-	(5,409)
Premiums paid for derivatives	(5,455)	(5,405)	(4,016)	(2,233)
Interest expense	14,845	15,117	15,547	15,765
Litigation settlement	-	-	-	(42,500)
Loss on disposal of assets, net	616	1,207	939	670
Adjusted EBITDA	$160,610	$132,370	$122,906	$153,218

Cash Flow and Free Cash Flow

Free Cash Flow

Historic Free Cash Flow is calculated as estimated cash flows from operating activities before changes in assets and liabilities, less cash and non-cash capital investments made during the period, excluding non-budgeted acquisitions. Management believes this is useful to investors in evaluating the operating trends in its business due to production, commodity prices, operating costs and other related factors.
The following table presents a reconciliation of net cash provided by operating activities (GAAP) to cash flow (non-GAAP) and free cash flow (non-GAAP):

(in thousands, unaudited)	FY-18	1Q-19	2Q-19
Net cash provided by operating activities	$537,804	$77,458	$183,811
Less:			
Changes in working capital	427	(35,686)	11,541
Adjusted cash flows from operating activities (“Cash flow”)	537,377	113,144	172,270
Less:			
Costs incurred, including LMS investments (“Capital”)	644,000	164,000	132,000
Free cash flow	($106,623)	($50,856)	$40,270

Future Free Cash Flow is calculated as estimated future cash flows from operating activities before changes in assets and liabilities, less cash and non-cash capital investments expected to be made during the period, excluding non-budgeted acquisitions.