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): August 12, 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 7.01. Regulation FD Disclosure.

Laredo Petroleum, Inc.'s (the "Company") President, Jason Pigott, is scheduled to present at the EnerCom Oil and Gas Conference on August 13, 2019 in Denver, Colorado. On August 12, 2019, the Company posted to its website a Corporate Presentation (the "Presentation") that it will utilize during the conference. The Presentation is available on the Company's website, www.laredopetro.com, and is attached to this Current Report on Form 8-K as Exhibit 99.1 and incorporated into this Item 7.01 by reference.

All statements in this Item 7.01, the Presentation and any oral statements made during the conference, 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 Securities and Exchange Commission 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	Corporate Presentation August 12, 2019.
104	Cover Page Interactive Data File (formatted as Inline XBRL).

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: August 12, 2019	By:	/s/ Michael T. Beyer
		Michael T. Beyer
		Senior Vice President and Chief Financial Officer


LAREDO PETROLEUM
Corporate Presentation
August 2019

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.

Laredo Petroleum Overview

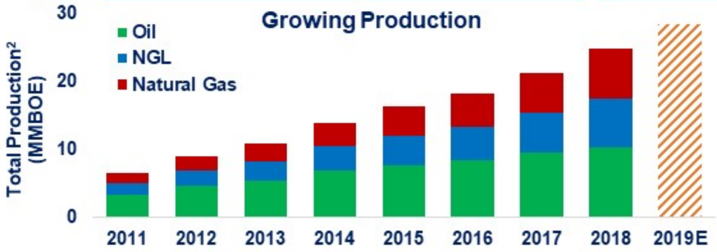
Laredo Petroleum (LPI)

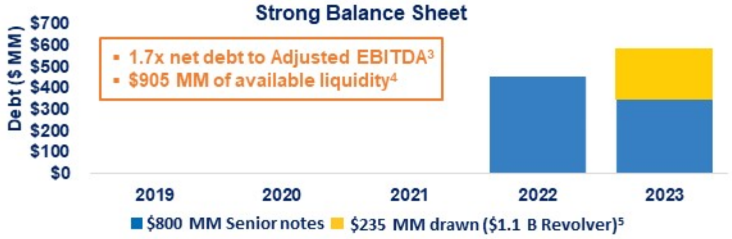
Market Cap: $590 MM[1]

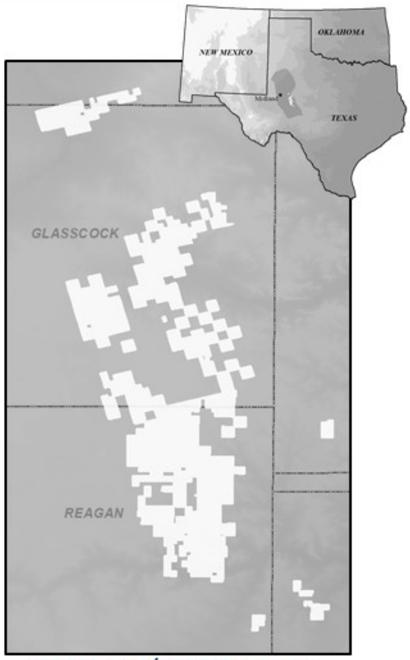
Operations: Permian Basin (TX), Headquarters: Tulsa, OK

2Q-19

30,400	82,200	~260
Barrels of Oil per Day	BOE per day	Employees







137,831 gross/ 122,787 net acres

[1] As of 8/8/2019
[2] 2011 - 2014 results have been converted to 3-stream using actual gas plant economics. 2011 - 2013 results have been adjusted for Granite Wash divestiture, closed August 1, 2013;
[3] As of 2Q-19. See Appendix for the calculation of net debt to Adjusted EBITDA and a reconciliation of Net Income to Adjusted EBITDA
[4] See Appendix for the calculation of liquidity
[5] 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

LAREDO PETROLEUM

2019: A Transformational Year

Optimized operations
- $700,000/well savings since YE-18
- Moved to wider-spaced development

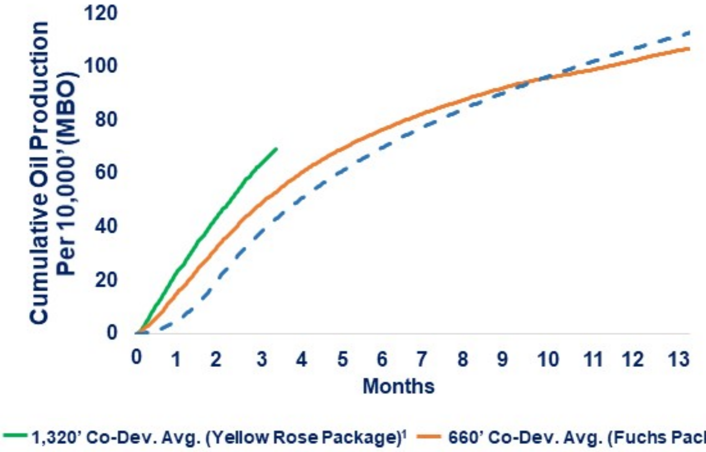
Aligned personnel costs with activity
- $30 MM/year annualized cash & non-cash expenses & capital savings expected
- Reduced officer positions by ~40%

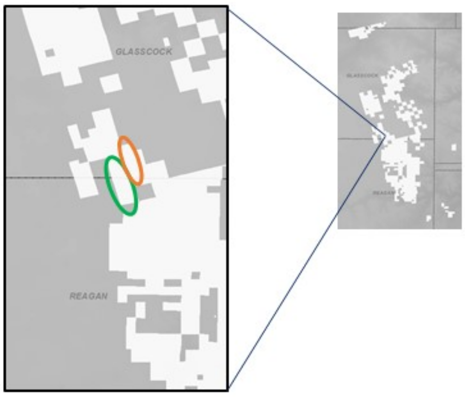
Reconstructed Senior Management Team
- New President, COO, CFO & GC

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

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**

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[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

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

Surpassing Guidance on Production & Expenses

2Q-19A Select Results

Production

Oil Production
30.4 MBO/d
7% Beat vs guidance

Total Production
82.3 MBOE/d
5% Beat vs guidance

Controllable Cash Costs

Lease Operating Expense
$3.16/BOE
4% Beat vs guidance

G&A Cash Expense
$1.53/BOE
24% Beat vs guidance

40% lower 2Q-19A controllable cash costs versus 2Q-19A peer average

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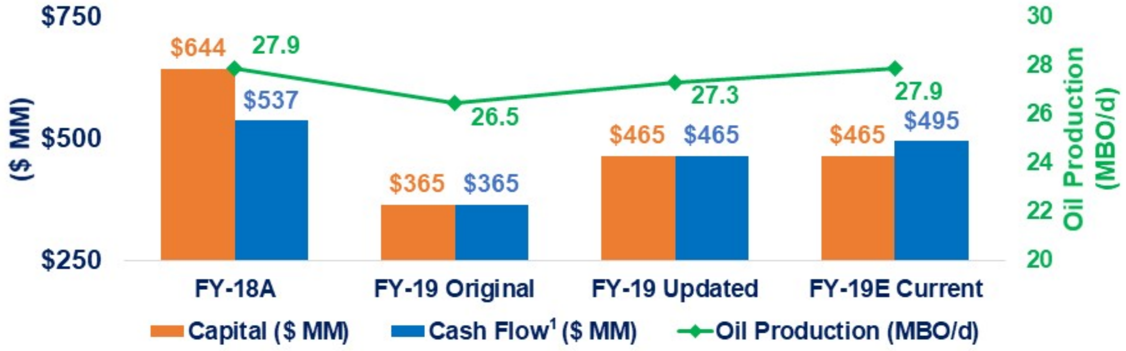
[1]Representative of unit expenses
Note: Peers include - CDEV, CPE, CRZO, JAG, MTDR, QEP, SM

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

High-Grading Inventory to Reduce Risk & Maximize Returns

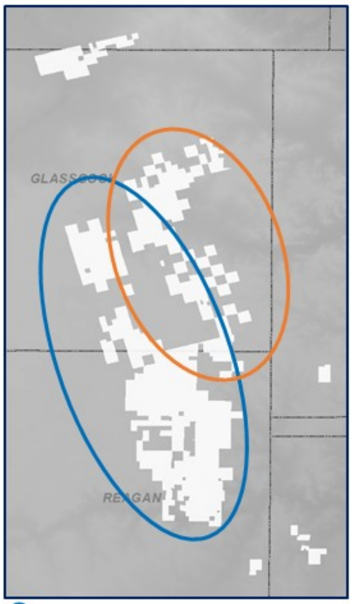
UWC/MWC Combined

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

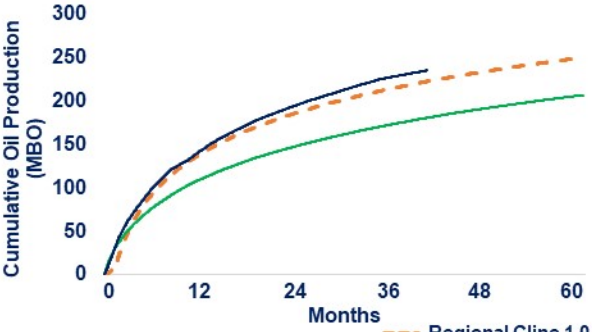
Continually optimizing inventory to incorporate current spacing and cost assumptions

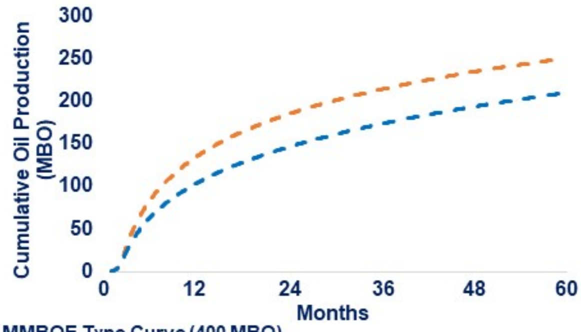
[1]Inventory expected to average oil type curve productivity

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

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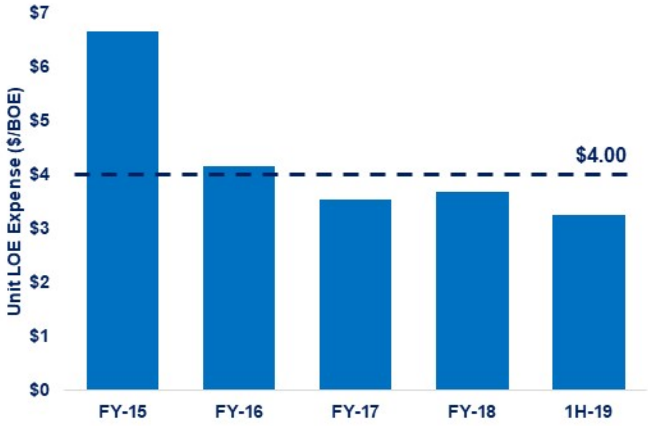
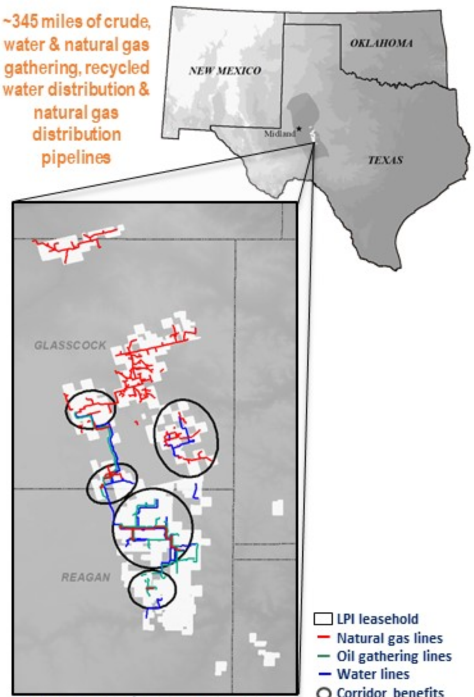
Existing Infrastructure Reduces Operating Costs

12 consecutive quarters with unit LOE less than $4.00/BOE



~345 miles of crude, water & natural gas gathering, recycled water distribution & natural gas distribution pipelines



137,831 gross/ 122,787 net acres

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Note: Map, acreage count and statistics as of 6/30/19

Infrastructure Protects the Environment & Enhances Economics

LPI In-Place Infrastructure

60 Miles
Crude oil gathering pipelines

170 miles
Natural gas gathering pipelines

110 Miles
Water gathering & distribution pipelines

54 MBWPD
Produced water recycling capacity

Environmental Impact

Truckloads eliminated from the field	Barrels of water recycled	Additional gas sold vs. vented/flared
>220,000	>8,500,000	>3.2 Bcf

Shareholder Value

$0.51/BOE
Reduction in unit LOE, helping to control operating costs

$110,000
Per well reduction in capital due to in-place water infrastructure

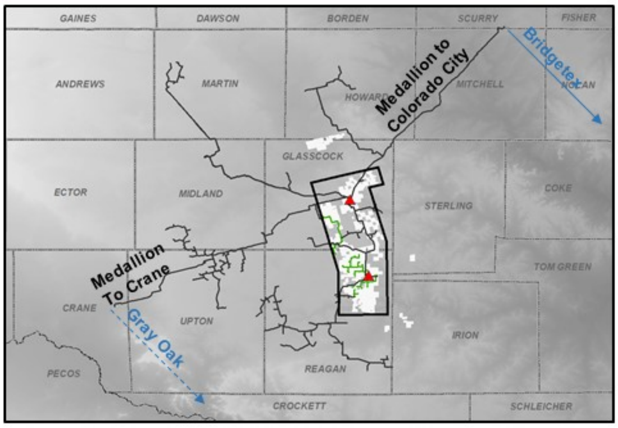
$10.4 MM
Revenue from natural gas sold versus vented/flared

Note: Existing infrastructure as of 7/17/19
Environmental impact and shareholder value based on FY-18

Oil Value Enhanced Via Gulf Coast Access

Gross Physical Transportation Contracts:

- **Medallion firm transportation secured for all crude oil produced within dedication area**
- **10 MBOPD firm transportation on Bridgetex through 1Q-22, with option to extend through 1Q-26 (USGC pricing)**
- **Firm transportation on Gray Oak through 4Q-26E (Brent-related pricing):**
  - **Year 1: 25 MBOPD**
  - **Years 2 - 7: 35 MBOPD**



Firm transportation to the US Gulf Coast provides exposure to Brent-based pricing for majority of crude oil production

Note: Map as of 6/30/19

2019 Product Hedges Protect Cash Flow

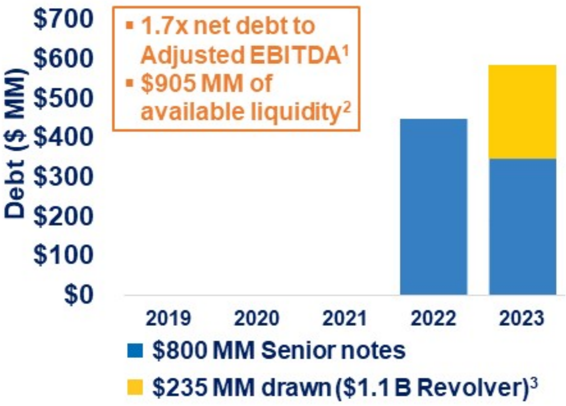
% Hedged[1]	Oil: 95%	Natural Gas: 70%

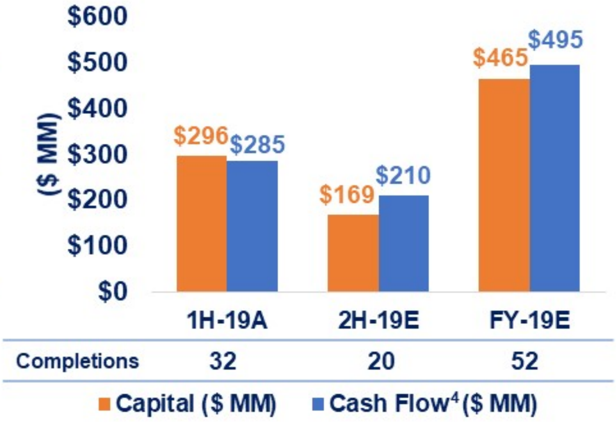
% Hedged[1]	Ethane: 65%	Propane: 65%	N. Butane: 70%	I. Butane: 70%	N. Gasoline: 65%

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

[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

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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

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

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.