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): November 5, 2018

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)

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

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

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

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

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

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

Emerging Growth Company o

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

Item 2.02. Results of Operations and Financial Condition.

On November 5, 2018, Laredo Petroleum, Inc. (the "Company") announced its financial and operating results for the quarter ended September 30, 2018. 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 November 6, 2018 at 7:30 am Central Time to discuss these results and during which it will make reference to the Presentation. To access the call, please dial 1-877-930-8286 or 1-253-336-8309 for international callers, and use conference code 4686158. A replay of the call will be available through Tuesday, November 13, 2018, by dialing 1-855-859-2056, and using conference code 4686158. 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 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 exhibits 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 November 5, 2018, the Company furnished 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 and incorporated into this Item 7.01 by reference.

On November 5, 2018, 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. 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 Item 7.01 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 exhibits 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 November 5, 2018 announcing financial and operating results.
99.2	Presentation dated November 5, 2018.

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: November 5, 2018	By:	/s/ Richard C. Buterbaugh
		Richard C. Buterbaugh
		Executive Vice President & 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 2018 Third-Quarter Financial and Operating Results

TULSA, OK - November 5, 2018 - Laredo Petroleum, Inc. (NYSE: LPI) ("Laredo" or "the Company") today announced its 2018 third-quarter results, reporting net income attributable to common stockholders of $55.1 million, or $0.24 per diluted share. Adjusted Net Income, a non-GAAP financial measure, for the third quarter of 2018 was $62.4 million, or $0.27 per diluted share. Adjusted EBITDA, a non-GAAP financial measure, for the third quarter of 2018 was $160.6 million. Please see supplemental financial information at the end of this news release for reconciliations of non-GAAP financial measures.

2018 Third-Quarter Highlights

- Produced a Company record 71,382 barrels of oil equivalent ("BOE") per day, an increase of 19% from third-quarter 2017
- Increased cash flows from operations to $145.9 million, balancing operating cash flows with capital expenditures
- Increased Adjusted EBITDA to $160.6 million, up 23% from the third quarter of 2017
- Improved drilling efficiency approximately 25%, reducing average days to drill a normalized 10,000-foot horizontal well to a Company record of 8.6 days from 11.4 days in third-quarter 2017

"With Laredo balancing operating cash flow and capital expenditures in the third quarter of 2018, as forecasted in our 2018 budget, we similarly plan to manage activity levels in 2019 to minimize any outspend," commented Randy A. Foutch, Chairman and Chief Executive Officer. "We intend to continue exercising this discipline in the future and invest capital with a focus on returns and growth on a debt-adjusted per share basis."

"During the past 18 months, Laredo has worked to implement a development plan that maximizes the long-term value of our leasehold through high-density drilling. We have executed six packages of wells designed to co-develop multiple landing points in our Upper and Middle Wolfcamp formations at a density of 24 to 32 wells per drilling spacing unit and have another three high-density packages in process. The results of these high-density packages have successfully demonstrated that this development plan can increase the total value of our leasehold, albeit at lower per well value than lower-density development. As we seek to balance rate of return and capital efficiency with overall value, while minimizing our outspend, we are beginning to widen our well spacing and develop packages at a lower density."

E&P Update

In the third quarter of 2018, Laredo completed 16 gross (16 net) horizontal wells with an average completed lateral length of approximately 11,300 feet. Laredo produced a Company record 71,382 BOE per day in third-quarter 2018, higher than Company guidance of 71,000 BOE per day.

During third-quarter 2018, 14 of the 16 completed wells were in two larger, high-density packages. The six-well Sugg-D 104 package was a co-development package based on 24 wells per drilling spacing unit ("DSU") and an average lateral length of approximately 15,000 feet. Due in part to the longer clean-up times associated with 15,000-foot laterals, this package is currently underperforming the Company's lateral-length adjusted Upper/Middle Wolfcamp type curve. Although production has reached its peak, the Company expects the underperformance versus the type curve to improve as the package's decline rate is relatively shallow. The second package, the eight-well Barbee package based primarily on 32 wells per DSU, was completed at the end of the third quarter of 2018 and has not yet reached peak production.

The 11-well Fuchs package, a high-density co-development package based on 32 wells per DSU and completed in the second quarter of 2018, is producing mixed results. Laredo is evaluating production data to better understand the individual productivity impact of landing point selection, lateral length and parent/child impact in relation to horizontal and vertical spacing in this package.

Operational efficiencies continued to improve in the third quarter of 2018. Drilling operations set a Company record for average drilling days per 10,000-foot lateral of 8.6 days, a 25% improvement from the third quarter of 2017. Combined with the 53% improvement in completions efficiencies compared to third-quarter 2017, Laredo expects gross completed lateral feet per rig to increase approximately 50% in 2018 versus 2017.

During the third quarter of 2018, the Company began utilizing in-basin sand on all of its completions, resulting in the previously expected savings of approximately $400,000 per well. Laredo estimates its current well cost for a 10,000-foot Upper/Middle Wolfcamp well to be approximately $7.4 million.

Unit lease operating expenses ("LOE") decreased in the third quarter of 2018 to $3.63 per BOE, remaining below $4.00 per BOE for the ninth consecutive quarter. The Company's previous investments in field infrastructure, including water gathering and recycling and gas compression, are a significant recurring contributor to LOE savings, reducing unit LOE by an estimated $0.43 per BOE in third-quarter 2018.

Laredo expects to complete 18 gross horizontal wells (15.3 net) in the fourth quarter of 2018 with an average lateral length of approximately 10,000 feet. The Company is currently utilizing four horizontal drilling rigs and two completion crews. Reduced cycle times, driven by continued improvements in operational efficiencies, are expected to enable the early completion of Laredo's budgeted 2018 drilling program. The Company therefore anticipates dropping one completion crew in mid-November and operating with one completion crew for the remainder of 2018.

Based on the productivity of high-density packages developed at 24 to 32 wells per DSU in the Upper/Middle Wolfcamp, Laredo has begun to plan lower-density development on packages to be drilled at the end of the fourth quarter of 2018 and is building the Company's 2019 budget to include lower-density development. The Company believes lower-density development of 8 to 16 wells per DSU in the Upper/Middle Wolfcamp will better balance higher- return drilling and capital efficiency with future value. The majority of completions in the first half of 2019 will consist of higher-density packages, with the transition to completions of lower-density packages expected to occur in the second half of 2019.

2018 Capital Program

During the third quarter of 2018, Laredo invested approximately $134 million in drilling and completions activities. Other expenditures incurred during the quarter included approximately $5 million in bolt-on land acquisitions, lease extensions and data, approximately $2 million in infrastructure, including LMS investments, and approximately $8 million in other capitalized costs.

Through the first nine months of 2018, Laredo has invested approximately $496 million, excluding non-budgeted leasehold acquisitions of $16 million. The Company expects total capital expenditures, excluding non-budgeted acquisitions of approximately $630 million for full-year 2018, in-line with the previously announced 2018 capital program.

Liquidity

At September 30, 2018, the Company had cash and cash equivalents of approximately $50 million and undrawn capacity under its senior secured credit facility of $1.03 billion, resulting in total liquidity of approximately $1.08 billion.

On October 23, 2018, in connection with the semi-annual redetermination of the Company's senior secured credit facility, lenders reaffirmed the Company's borrowing base at $1.3 billion, with Laredo's aggregate elected commitment remaining at $1.2 billion.

At November 5, 2018, the Company had cash and cash equivalents of approximately $46 million and available capacity under its senior secured credit facility of $1.0 billion, resulting in total available liquidity of approximately $1.04 billion.

Share Repurchase Program

During the third quarter of 2018, the Company repurchased 1,170,190 shares of common stock at a weighted-average price of $8.41 per share for $9.9 million. Through September 30, 2018, Laredo has repurchased 11,048,742 shares of common stock at a weighted-average price of $8.78 per share for $97.1 million under the authorized share repurchase program.

Commodity Derivatives

Laredo maintains a disciplined hedging program to mitigate the variability in its anticipated cash flow due to fluctuations in commodity prices. The Company utilizes a combination of puts, swaps and collars, entering into contracts solely with banks that are part of its senior secured credit facility. For the fourth quarter of 2018, Laredo has hedges in place for approximately 90% of the Company's anticipated oil production, approximately 50% of anticipated natural gas production and approximately 20% of anticipated natural gas liquids production. 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 2018 total production growth guidance to approximately 17% and reducing oil production growth guidance to approximately 7.5% as compared to 2017. The table below reflects the Company's guidance for the fourth quarter of 2018.

	4Q-2018E
Total production (MBOE/d)	70.5
Oil production (MBO/d)	28.2
Average sales price realizations (without derivatives):	
Oil (% of WTI)	90%
NGL (% of WTI)	33%
Natural gas (% of Henry Hub)	40%
Operating costs & expenses:	
Lease operating expenses ($/BOE)	$3.65
Production and ad valorem taxes (% of oil, NGL and natural gas revenues)	6.25%
Transportation and marketing expenses ($/BOE)	$0.80
Midstream service expenses ($/BOE)	$0.15
General and administrative:	
Cash ($/BOE)	$2.50
Non-cash stock-based compensation, net ($/BOE)	$1.40
Depletion, depreciation and amortization ($/BOE)	$9.00

Conference Call Details

On Tuesday, November 6, 2018, at 7:30 a.m. CT, Laredo will host a conference call to discuss its third-quarter 2018 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, using conference code 4686158, approximately 10 minutes prior to the scheduled conference time. International participants should dial 253.336.8309, also using conference code 4686158. A telephonic replay will be available approximately two hours after the call on November 6, 2018 through Tuesday, November 13, 2018. Participants may access this replay by dialing 855.859.2056, using conference code 4686158.

About Laredo

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

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

Forward-Looking Statements

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

General risks relating to Laredo include, but are not limited to, the decline in prices of oil, natural gas liquids and natural gas and the related impact to financial statements as a result of asset impairments and revisions to reserve estimates, the increase in service and supply costs, tariffs on steel, pipeline transportation constraints in the Permian Basin, hedging activities, possible impacts of pending or potential litigation, the suspension or discontinuance of share repurchases at any time and other factors, including those and other risks described in its Annual Report on Form 10-K for the year ended December 31, 2017, and those set forth from time to time in other filings with the Securities and Exchange Commission ("SEC") including, but not limited to, its Quarterly Report on Form 10-Q for the quarter ended June 30, 2018. 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.*

Laredo Petroleum, Inc.
Condensed consolidated statements of operations

(in thousands, except per share data)	Three months ended September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
	(unaudited)		(unaudited)	
Revenues:				
Oil, NGL and natural gas sales	$ 225,864	$ 157,558	$ 631,859	$ 438,131
Midstream service revenues	2,255	2,446	6,590	8,148
Sales of purchased oil	51,627	45,814	252,039	135,546
Total revenues	279,746	205,818	890,488	581,825
Costs and expenses:				
Lease operating expenses	23,873	19,594	68,466	56,690
Production and ad valorem taxes	14,015	9,558	38,232	26,811
Transportation and marketing expenses	5,036	—	6,570	—
Midstream service expenses	728	1,174	1,824	2,986
Costs of purchased oil	51,210	47,385	252,452	141,661
General and administrative	23,397	25,000	74,956	72,605
Depletion, depreciation and amortization	55,963	41,212	152,278	113,327
Other operating expenses	1,114	1,443	3,341	3,906
Total costs and expenses	175,336	145,366	598,119	417,986
Operating income	104,410	60,452	292,369	163,839
Non-operating income (expense):				
Gain (loss) on derivatives, net	(32,245)	(27,441)	(69,211)	38,127
Income from equity method investee(1)	—	2,371	—	7,910
Interest expense	(14,845)	(23,697)	(42,787)	(69,590)
Other, net	(883)	(658)	(3,962)	127
Non-operating expense, net	(47,973)	(49,425)	(115,960)	(23,426)
Income before income taxes	56,437	11,027	176,409	140,413
Income tax benefit (expense):				
Current	381	—	381	—
Deferred	(1,768)	—	(1,768)	—
Total income tax expense:	(1,387)	—	(1,387)	—
Net income	$ 55,050	$ 11,027	$ 175,022	$ 140,413
Net income per common share:				
Basic	$ 0.24	$ 0.05	$ 0.75	$ 0.59
Diluted	$ 0.24	$ 0.05	$ 0.75	$ 0.57
Weighted-average common shares outstanding:				
Basic	230,605	239,306	233,228	239,017
Diluted	231,639	244,887	234,207	244,693

(1) On October 30, 2017, LMS, together with Medallion Midstream Holdings, LLC, which is owned and controlled by an affiliate of the third-party interest holder, The Energy & Minerals Group, completed the sale of 100% of the ownership interests in Medallion Gathering & Processing, LLC, a Texas limited liability company formed on October 12, 2012, which, together with its wholly-owned subsidiaries (collectively, "Medallion"), to an affiliate of Global Infrastructure Partners ("GIP"), for cash consideration of $1.825 billion (the "Medallion Sale"). LMS' net cash proceeds for its 49% ownership interest in Medallion in 2017 were $829.6 million, before post-closing adjustments and taxes, but after deduction of its proportionate share of fees and other expenses associated with the Medallion Sale. On February 1, 2018, closing adjustments were finalized and LMS received additional net cash of $1.7 million for total net cash proceeds before taxes of $831.3 million. The Medallion Sale closed pursuant to the membership interest purchase and sale agreement, which provides for potential post-closing additional cash consideration that is structured based on GIP's realized profit at exit. There can be no assurance as to when and whether the additional consideration will be paid.

Laredo Petroleum, Inc.
Condensed consolidated statements of cash flows

	Three months ended September 30,		Nine months ended September 30,	
(in thousands)	2018	2017	2018	2017
	(unaudited)		(unaudited)	
Cash flows from operating activities:				
Net income	$ 55,050	$ 11,027	$ 175,022	$ 140,413
Adjustments to reconcile net income to net cash provided by operating activities:				
Deferred income tax expense	1,768	—	1,768	—
Depletion, depreciation and amortization	55,963	41,212	152,278	113,327
Non-cash stock-based compensation, net	8,733	8,966	28,748	26,877
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	32,245	27,441	69,211	(38,127)
Settlements (paid) received for matured derivatives, net	(3,888)	13,635	(5,943)	34,791
Settlements received for early terminations of derivatives, net	—	—	—	4,234
Premiums paid for derivatives	(5,455)	(1,448)	(14,930)	(13,542)
Other, net[1]	3,394	786	12,338	(1,134)
Cash flows from operations before changes in assets and liabilities	147,810	101,619	418,492	266,839
(Increase) decrease in current assets and liabilities, net	(313)	13,762	(9,685)	5,579
Increase in other noncurrent assets and liabilities, net	(1,570)	(231)	(279)	(367)
Net cash provided by operating activities	145,927	115,150	408,528	272,051
Cash flows from investing activities:				
Acquisitions of oil and natural gas properties	—	—	(16,340)	—
Capital expenditures:				
Oil and natural gas properties	(180,936)	(148,946)	(522,470)	(381,165)
Midstream service assets	(559)	(5,563)	(5,764)	(11,680)
Other fixed assets	(980)	(921)	(5,945)	(3,604)
Investment in equity method investee[1]	—	(24,572)	—	(24,572)
Proceeds from disposition of equity method investee, net of selling costs[1]	—	—	1,655	—
Proceeds from dispositions of capital assets, net of selling costs	116	687	12,433	64,128
Net cash used in investing activities	(182,359)	(179,315)	(536,431)	(356,893)
Cash flows from financing activities:				
Borrowings on Senior Secured Credit Facility	80,000	65,000	190,000	155,000
Payments on Senior Secured Credit Facility	(20,000)	(15,000)	(20,000)	(70,000)
Share repurchases	(9,837)	—	(97,055)	—
Other, net	72	(41)	(6,794)	(12,012)
Net cash provided by financing activities	50,235	49,959	66,151	72,988
Net increase (decrease) in cash and cash equivalents	13,803	(14,206)	(61,752)	(11,854)
Cash and cash equivalents, beginning of period	36,604	35,024	112,159	32,672
Cash and cash equivalents, end of period	$ 50,407	$ 20,818	$ 50,407	$ 20,818

(1) See footnote 1 to the condensed consolidated statements of operations.

Laredo Petroleum, Inc.
Selected operating data

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	2018	2017
	(unaudited)		(unaudited)	
Sales volumes:				
Oil (MBbl)	2,651	2,425	7,604	7,027
NGL (MBbl)	1,987	1,491	5,328	4,187
Natural gas (MMcf)	11,577	9,630	32,697	26,154
Oil equivalents (MBOE)(1)(2)	6,567	5,521	18,381	15,573
Average daily sales volumes (BOE/D)(2)	71,382	60,011	67,330	57,044
% Oil(2)	40%	44%	41%	45%
Average sales Realized Prices(2):				
Oil, without derivatives ($/Bbl)(3)	$ 60.36	$ 45.44	$ 61.80	$ 44.67
NGL, without derivatives ($/Bbl)(3)	$ 25.57	$ 18.58	$ 21.77	$ 16.32
Natural gas, without derivatives ($/Mcf)(3)	$ 1.30	$ 2.04	$ 1.40	$ 2.14
Average price, without derivatives ($/BOE)(3)	$ 34.39	$ 28.54	$ 34.38	$ 28.13
Oil, with derivatives ($/Bbl)(4)	$ 55.41	$ 50.72	$ 57.50	$ 49.08
NGL, with derivatives ($/Bbl)(4)	$ 23.99	$ 17.98	$ 20.95	$ 15.90
Natural gas, with derivatives ($/Mcf)(4)	$ 1.79	$ 2.10	$ 1.79	$ 2.17
Average price, with derivatives ($/BOE)(4)	$ 32.78	$ 30.80	$ 33.04	$ 30.07
Average costs per BOE sold(2):				
Lease operating expenses	$ 3.63	$ 3.55	$ 3.72	$ 3.64
Production and ad valorem taxes	2.13	1.73	2.08	1.72
Transportation and marketing expenses	0.77	—	0.36	—
Midstream service expenses	0.11	0.21	0.10	0.19
General and administrative:				
Cash	2.23	2.90	2.51	2.94
Non-cash stock-based compensation, net	1.33	1.62	1.56	1.73
Depletion, depreciation and amortization	8.52	7.46	8.28	7.28
Total costs and expenses	$ 18.72	$ 17.47	$ 18.61	$ 17.50
Cash margins per BOE sold(2):				
Realized	$ 25.52	$ 20.15	$ 25.61	$ 19.64
Hedged	$ 23.91	$ 22.41	$ 24.27	$ 21.58

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

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

(3) Realized oil, NGL and natural gas prices are the actual prices received when control passes to the purchaser/customer adjusted for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. See "Transportation and marketing expenses" under "Average costs per BOE sold" in the table above for costs incurred prior to control passing to the final customer per BOE.

(4) Price reflects the after-effects of our derivative transactions on our average Realized 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.

Laredo Petroleum, Inc.
Costs incurred

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

	Three months ended September 30,		Nine months ended September 30,	
(in thousands)	**2018**	**2017**	**2018**	**2017**
	(unaudited)		(unaudited)	
Property acquisition costs:				
Evaluated	$ —	$ —	$ 13,847	$ —
Unevaluated	—	—	2,790	—
Exploration costs	7,502	7,136	18,747	28,337
Development costs	139,748	160,359	467,582	397,255
Total costs incurred	$ 147,250	$ 167,495	$ 502,966	$ 425,592

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

Non-GAAP financial measures

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

Adjusted Net Income

Adjusted Net Income is a non-GAAP financial measure we use to evaluate performance, prior to income tax expense or benefit, 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):

(in thousands, except per share data)	Three months ended September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
	(unaudited)		(unaudited)	
Income before income taxes	$ 56,437	$ 11,027	$ 176,409	$ 140,413
Plus:				
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	32,245	27,441	69,211	(38,127)
Settlements (paid) received for matured derivatives, net	(3,888)	13,635	(5,943)	34,791
Settlements received for early terminations of derivatives, net	—	—	—	4,234
Premiums paid for derivatives	(5,455)	(1,448)	(14,930)	(13,542)
Loss on disposal of assets, net	616	991	4,591	400
Adjusted income before adjusted income tax expense	79,955	51,646	229,338	128,169
Adjusted income tax expense[(1)]	(17,590)	(18,593)	(50,454)	(46,141)
Adjusted Net Income	$ 62,365	$ 33,053	$ 178,884	$ 82,028
Net income per common share:				
Basic	$ 0.24	$ 0.05	$ 0.75	$ 0.59
Diluted	$ 0.24	$ 0.05	$ 0.75	$ 0.57
Adjusted Net Income per common share:				
Basic	$ 0.27	$ 0.14	$ 0.77	$ 0.34
Diluted	$ 0.27	$ 0.13	$ 0.76	$ 0.34
Weighted-average common shares outstanding:				
Basic	230,605	239,306	233,228	239,017
Diluted	231,639	244,887	234,207	244,693

(1) Adjusted income tax expense is calculated by applying a statutory tax rate of 22% for the three and nine months ended September 30, 2018, in response to recent changes in the tax code, and 36% for the three and nine months ended September 30, 2017.

Adjusted EBITDA

Adjusted EBITDA is a non-GAAP financial measure that we define as net income or loss plus adjustments for income tax expense or benefit, 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, income or loss from equity method investee, proportionate Adjusted EBITDA of equity method investee 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)	Three months ended September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
	(unaudited)		(unaudited)	
Net income	$ 55,050	$ 11,027	$ 175,022	$ 140,413
Plus:				
Income tax expense	1,387	—	1,387	—
Depletion, depreciation and amortization	55,963	41,212	152,278	113,327
Non-cash stock-based compensation, net	8,733	8,966	28,748	26,877
Accretion expense	1,114	951	3,341	2,822
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	32,245	27,441	69,211	(38,127)
Settlements (paid) received for matured derivatives, net	(3,888)	13,635	(5,943)	34,791
Settlements received for early terminations of derivatives, net	—	—	—	4,234
Premiums paid for derivatives	(5,455)	(1,448)	(14,930)	(13,542)
Interest expense	14,845	23,697	42,787	69,590
Loss on disposal of assets, net	616	991	4,591	400
Income from equity method investee[1]	—	(2,371)	—	(7,910)
Proportionate Adjusted EBITDA of equity method investee[1][2]	—	6,789	—	19,755
Adjusted EBITDA	$ 160,610	$ 130,890	$ 456,492	$ 352,630

(1) See footnote 1 to the condensed consolidated statements of operations.

(2) Proportionate Adjusted EBITDA of Medallion, our equity method investee until its sale on October 30, 2017, is calculated as follows:

(in thousands)	Three months ended September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
	(unaudited)		(unaudited)	
Income from equity method investee	$ —	$ 2,371	$ —	$ 7,910
Adjusted for proportionate share of depreciation and amortization	—	4,418	—	11,845
Proportionate Adjusted EBITDA of equity method investee	$ —	$ 6,789	$ —	$ 19,755

# # #

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18-12

EXHIBIT 99.2

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

Third-Quarter 2018
Earnings Presentation

Forward-Looking / Cautionary Statements

This presentation, including any oral statements made regarding the contents of this presentation, contains 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. All statements, other than statements of historical fact, included in this presentation that address activities, events or developments that Laredo Petroleum, Inc. (together with its subsidiaries, the "Company", "Laredo" or "LPI") assumes, plans, expects, believes or anticipates will or may occur in the future are forward-looking statements. The words "believe," "expect," "may," "estimates," "will," "anticipate," "plan," "project," "intend," "indicator," "foresee," "forecast," "guidance," "should," "would," "could," "goal," "target," "suggest" or other similar expressions are intended to identify forward-looking statements, which are generally not historical in nature and are not guarantees of future performance. However, the absence of these words does not mean that the statements are not forward-looking. Without limiting the generality of the foregoing, forward-looking statements contained in this presentation specifically include the expectations of plans, strategies, objectives and anticipated financial and operating results of the Company, including the Company's drilling program, production, midstream and marketing services, hedging activities, capital expenditure levels, possible impacts of pending or potential litigation and other guidance included in this presentation. These statements are based on certain assumptions made by the Company based on management's expectations and perception of historical trends, current conditions, anticipated future developments and rate of return and other factors believed to be appropriate. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the Company, which may cause actual results to differ materially from those implied or expressed by the forward-looking statements. These include risks relating to financial performance and results, current economic conditions and resulting capital restraints, prices and demand for oil and natural gas (including but not limited to impacts on transportation constraints in the Permian Basin) and the related impact to financial statements as a result of asset impairments and revisions to reserve estimates, availability and cost of equipment and supplies and personnel, availability of sufficient capital to execute the Company's business plan, impact of compliance with legislation and regulations, including tariffs on steel, impacts of pending or potential litigation, impacts relating to the Company's share repurchase program (which may be suspended or discontinued by the Company at any time without notice), successful results from the Company's identified drilling locations, the Company's ability to replace reserves and efficiently develop and exploit its current reserves and other important factors that could cause actual results to differ materially from those projected as described in the Company's Annual Report on Form 10-K for the year ended December 31, 2017 and those in the Company's 10-Q for the quarter ended June 30, 2018, and other reports filed with the Securities and Exchange Commission ("SEC").

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 "unproved reserves," "resource potential," "estimated ultimate recovery," "EUR," "development ready," "type curve" or other descriptions of potential reserves or volumes of reserves which the SEC guidelines restrict from being included in filings with the SEC without strict compliance with SEC definitions. "Unproved reserves" refers to the Company's internal estimates of 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. The Company does not choose to include unproved reserve estimates in its filings with the SEC. "Estimated ultimate recovery", or "EUR", refers to the Company's internal estimates of per-well hydrocarbon quantities that may be potentially recovered from a hypothetical and/or actual well completed in the area. 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, 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. "Type curve" refers to a production profile of a well, or a particular category of wells, for a specific play and/or area. In addition, the Company's production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases.

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

3Q-18 Highlights & FY-18 Expectations

~6% — Daily total production growth QoQ from 2Q-18

~71 net wells — Increased anticipated FY-18E net horizontal completions

~17% — Increased anticipated FY-18E BOE production growth

~1.4x — Net debt to Adjusted EBITDA[1]

$97.1 million — Utilized, of $200 MM total authorization, to repurchase 11 MM shares through 9/30/18

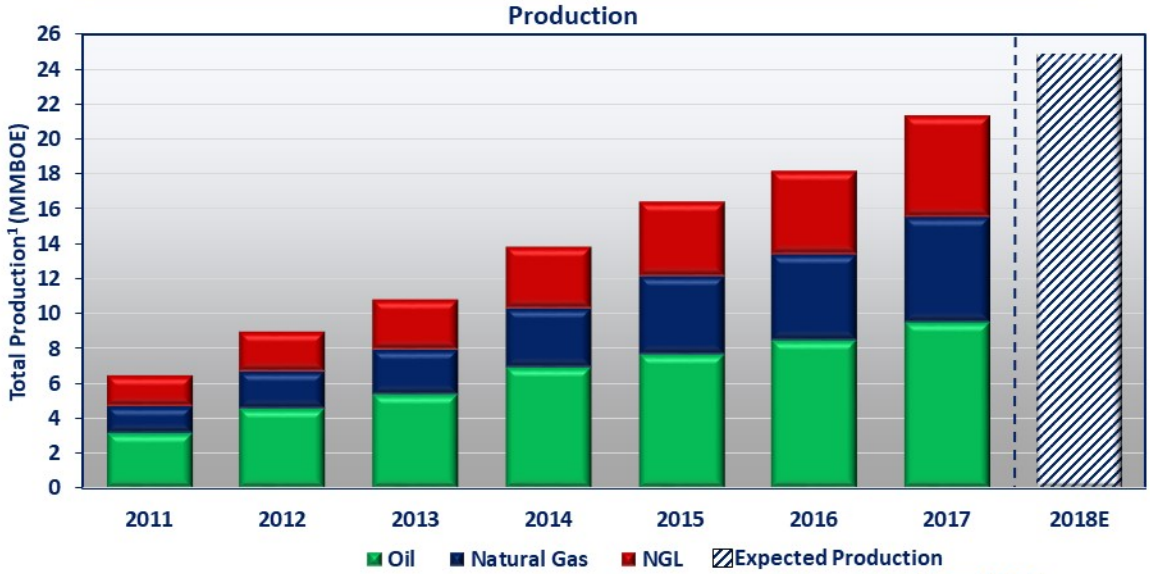
[1] Net debt to last quarter annualized Adjusted EBITDA is calculated as net debt as of 9/30/18 divided by 3Q-18 Adjusted EBITDA annualized for the year. Net debt as of 9/30/18 is calculated as the face value of long-term debt of $970 MM, reduced by cash on hand of ~$50 MM. See Appendix for a reconciliation of Net Income to Adjusted EBITDA

3Q-18 Guidance vs. Actuals

	Guidance	Actuals
Production (MBOE/d)..	71.0	71.4
Crude oil production (MBbl/d)..	29.1	28.8
Price Realizations (pre-hedge):		
Crude oil (% of WTI)..	86%	87%
Natural gas liquids (% of WTI)..	33%	37%
Natural gas (% of Henry Hub)..	47%	45%
Operating Costs & Expenses:		
Lease operating expenses ($/BOE)..	$3.65	$3.63
Midstream service expenses ($/BOE)..	$0.15	$0.11
Transportation and marketing expenses ($/BOE)..	$0.80	$0.77
Production and ad valorem taxes (% of oil, NGL and natural gas revenue)....	6.25%	6.21%
General and administrative expenses:		
Cash ($/BOE)..	$2.60	$2.23
Non-cash stock-based compensation ($/BOE)..	$1.55	$1.33
Depletion, depreciation and amortization ($/BOE)..	$8.30	$8.52

Aligned capital expenditures and cash flow from operations in 3Q-18

Consistent Production Growth



FY-18E YoY BOE production growth ~17%

~7.5% FY-18E YoY oil production growth

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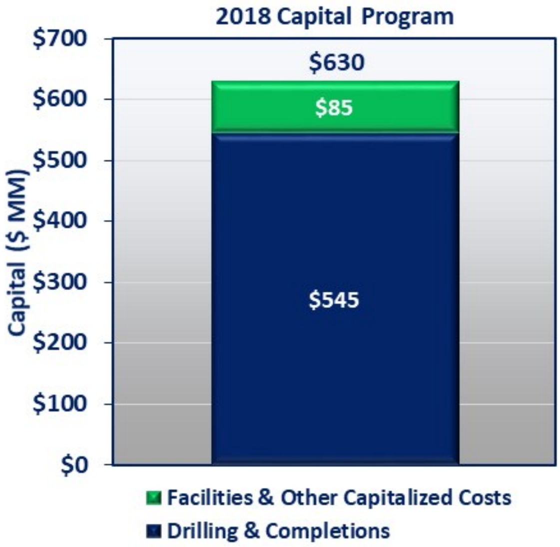
[1] 2011 - 2014 results have been converted to 3-stream using actual gas plant economics. 2011 - 2013 results have been adjusted for Granite Wash divestiture, closed August 1, 2013

2018 Current Capital Program



- Completing ~71 net wells
- ~10,400' avg. Hz lateral length
- ~96% avg. working interest
- Operational efficiencies enabling a reduction from two completions crews to one in mid-November
- ~$496 MM 9-month cumulative capital expenditures:
  - Drilling & Completions - $443 MM
  - Facilities & Other Capitalized Costs - $53 MM

Expect to spend ~$135 MM of capital in 4Q-18

Note: Excludes non-budgeted acquisitions

Focusing on Improving Capital Efficiency & Returns

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

Transitioning to lower-density development in 2019

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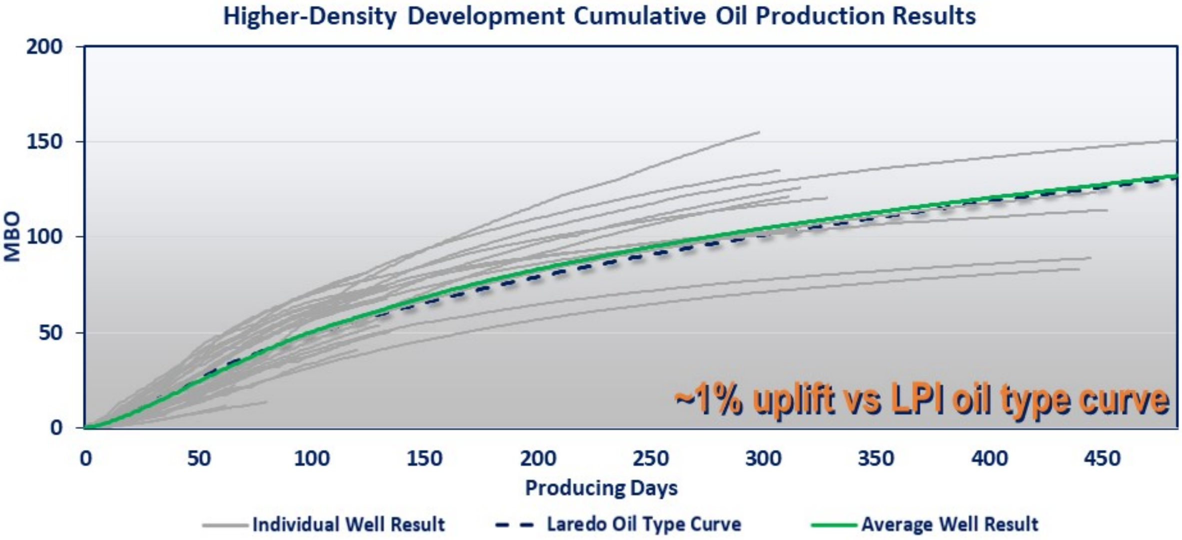
Note: Excludes ABW, Canyon and Spraberry formations
Drilling spacing unit (DSU)

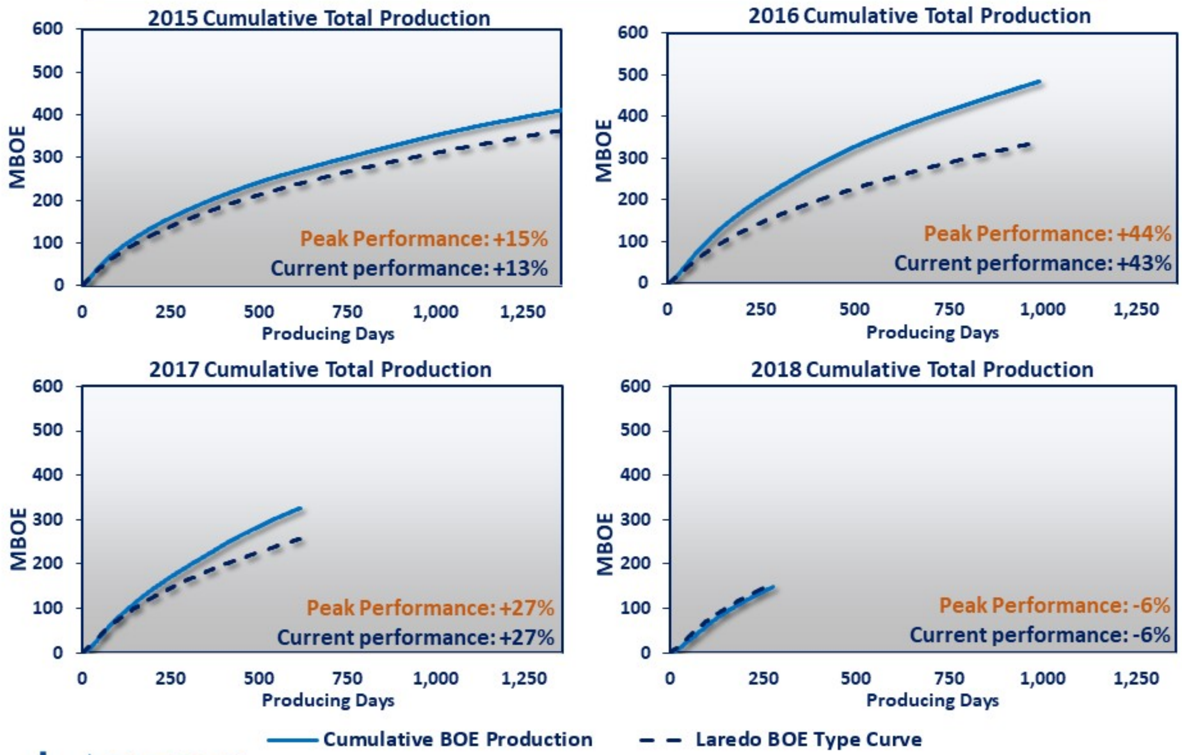
Higher-Density Development Increases Value per DSU



Higher-density packages are experiencing steeper than forecasted oil decline rates

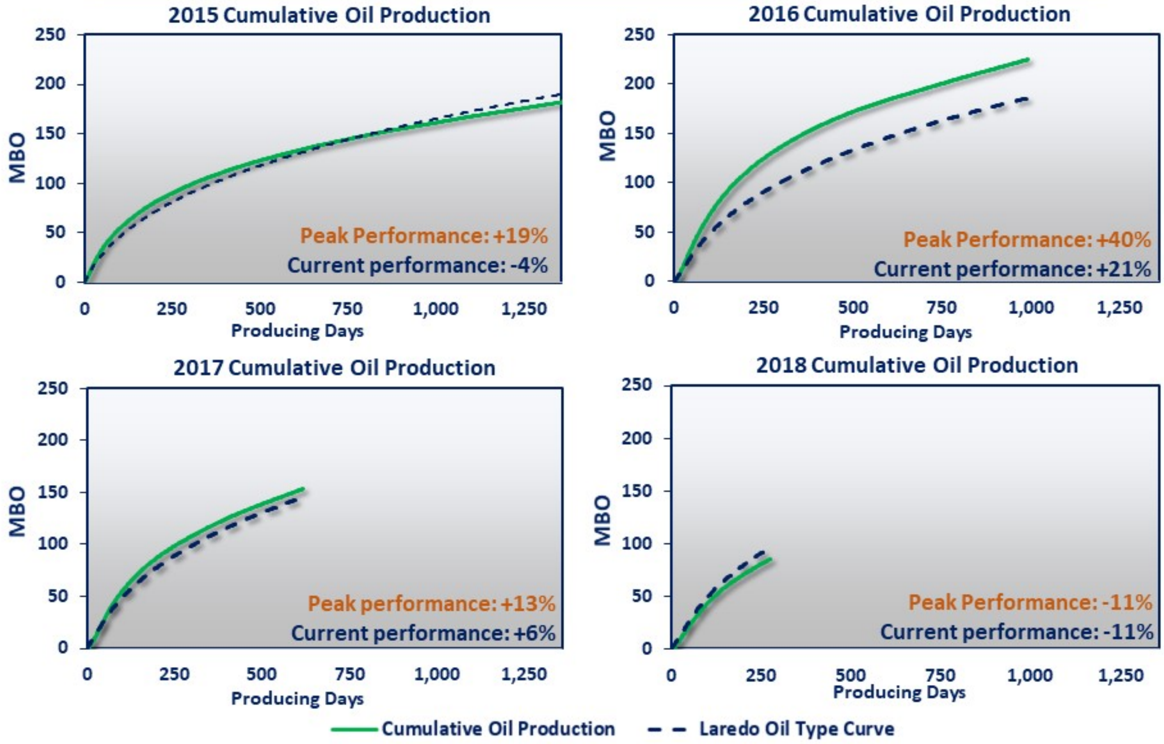
Note: Includes the 29 UWC/MWC wells from the Sugg A 157/158, Lane Trust, Fuchs & Sugg D 104 packages, normalized to 10,000' as of 10/26/18
Type curve representative of Laredo's 1.3 MMBOE UWC/MWC type curve which utilizes a 1.45 b-factor
Drilling spacing unit (DSU)

Yearly BOE Completions Performance



Note: Please see the Appendix slide titled, "Information For Slides 9 & 10" for relevant footnotes

Yearly Oil Completions Performance



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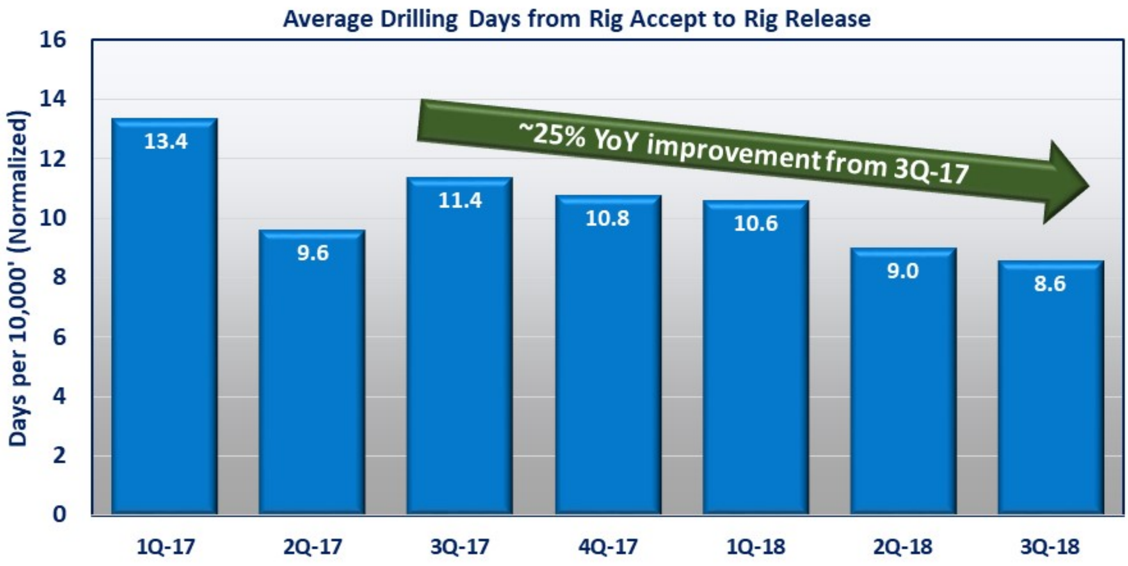
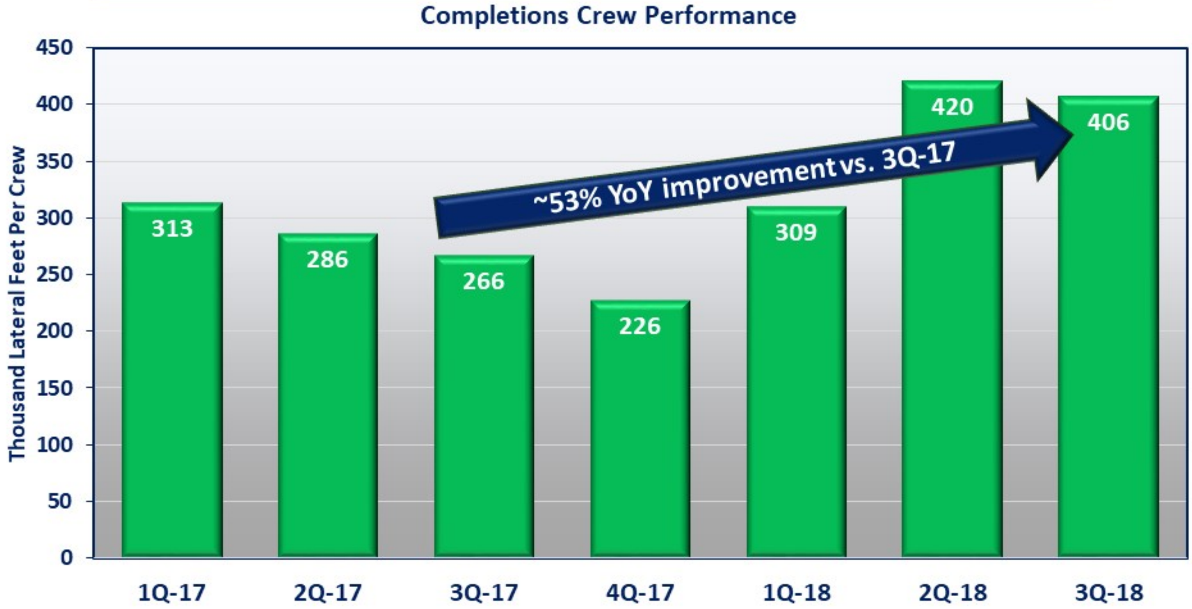
Note: Please see the Appendix slide titled, "Information For Slides 9 & 10" for relevant footnotes

Achieved New Drilling Days Record in 3Q-18



Integrated drilling and subsurface modelling is optimizing drilling operations

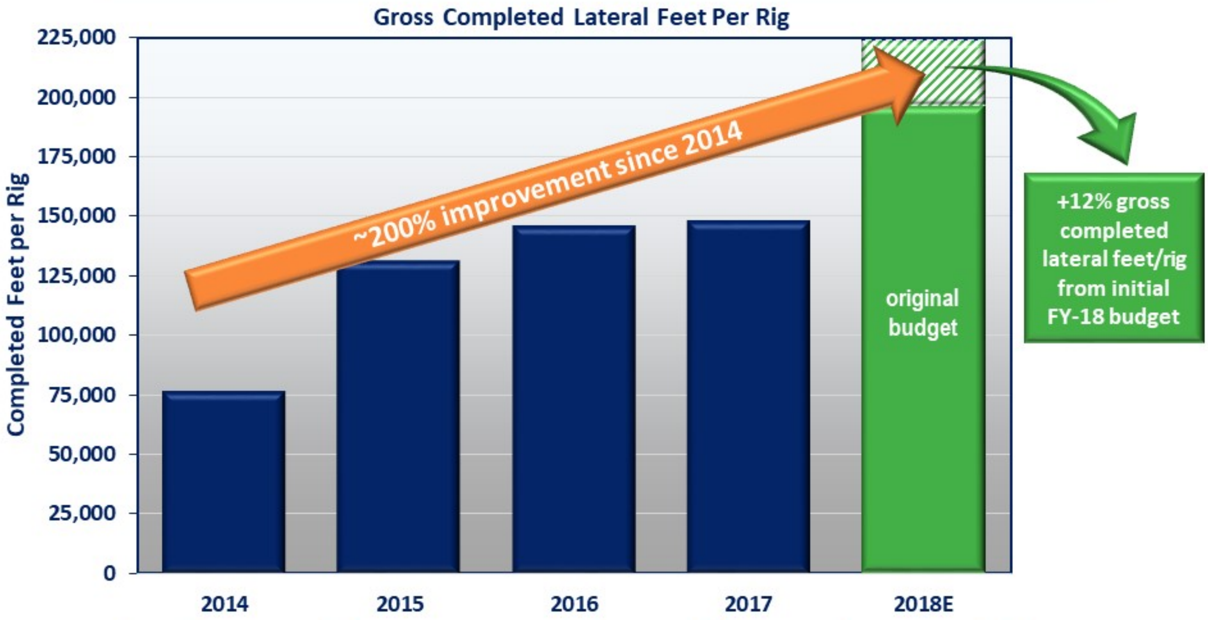
Completions Efficiencies Improving Cycle Times



High-grading of completions service providers and a focus on best practices is driving efficiency improvements

Note: Completions efficiencies data representative of annualized quarterly numbers

Continued Efficiency Improvements



Continuous improvement from drilling & completions efficiencies enable us to do more with less

Note: Statistics as of 9/30/2018

Continued Focus on Operating Costs

Nine

Quarters below $4.00/BOE

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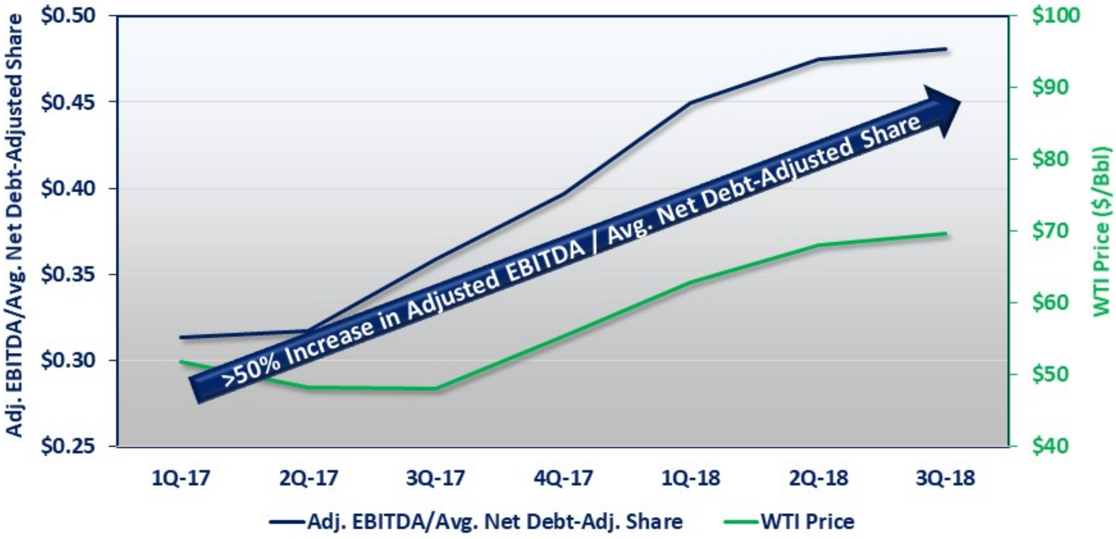
Increasing Adjusted EBITDA Per Average Net Debt-Adjusted Share



~1.5x **Grew adjusted EBITDA per average net debt-adjusted share faster than the increase in WTI price since 1Q-17**

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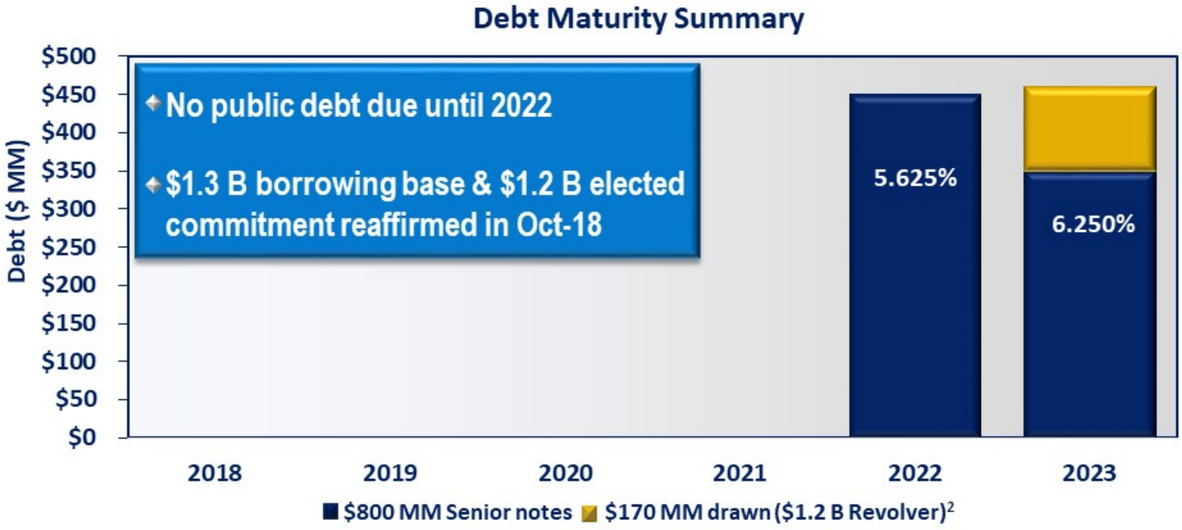
Maintaining A Strong Balance Sheet

~1.4x net debt to Adjusted EBITDA[1]

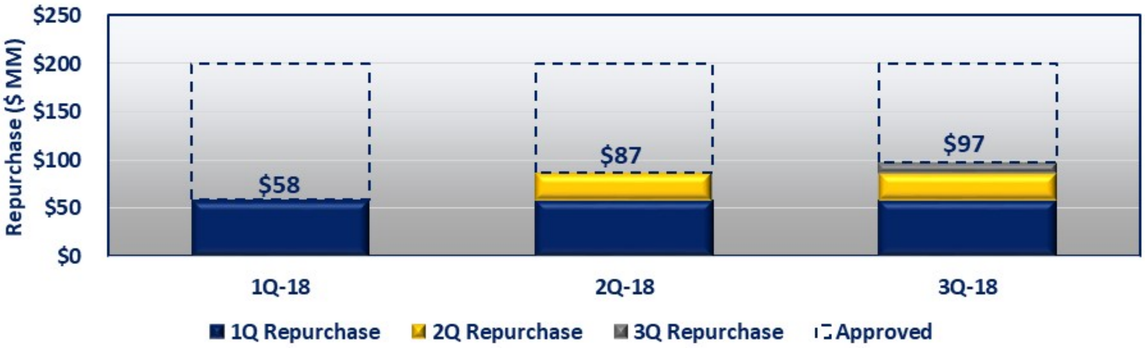


[1] Net debt to last quarter annualized Adjusted EBITDA is calculated as net debt as of 9/30/18 divided by 3Q-18 Adjusted EBITDA annualized for the year. Net debt as of 9/30/18 is calculated as the face value of long-term debt of $970 MM, reduced by cash on hand of ~$50 MM. See Appendix for a reconciliation of Net Income to Adjusted EBITDA

[2] As of 09/30/18, with $1.2 B aggregate elected commitment in place under Fifth Amended and Restated Senior Secured Credit Facility

Stock Repurchase Program - Update

11,048,742 shares of common stock repurchased with a weighted-average share price of $8.78/share



Laredo has successfully executed ~50% of its 24-month Board-approved stock repurchase program

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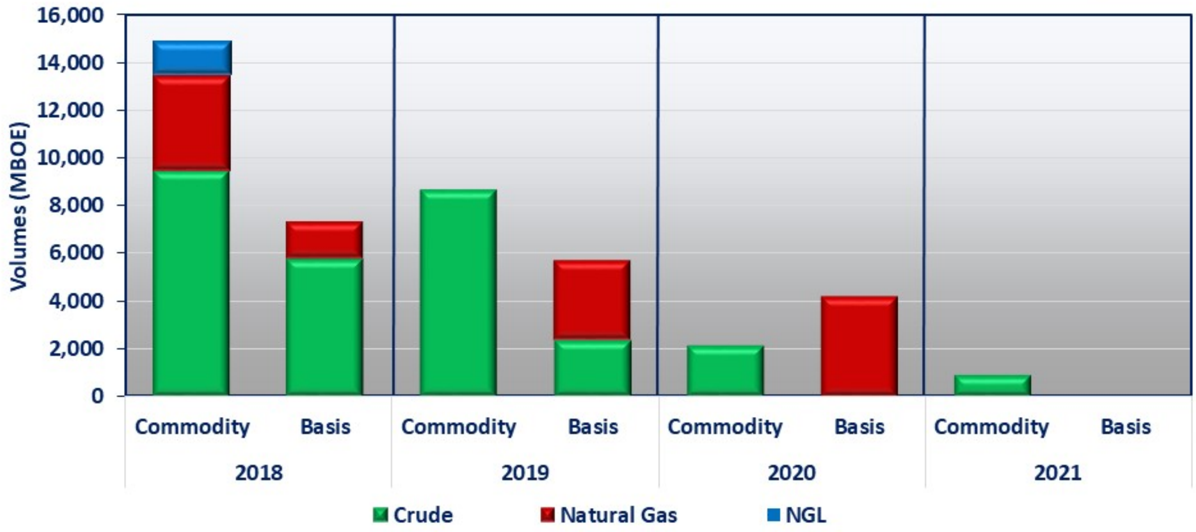
Note: Data through 9/30/2018

Consistent Financial Hedging Program



~60% Total production hedged for 4Q-18E

Note: Includes hedges executed through 11/5/18

4Q-18 Guidance

	4Q-18E
Production (MBOE/d)	70.5
Crude oil production (MBbl/d)	28.2
Price Realizations (pre-hedge):	
Crude oil (% of WTI)	90%
Natural gas liquids (% of WTI)	33%
Natural gas (% of Henry Hub)	40%
Operating Costs & Expenses:	
Lease operating expenses ($/BOE)	$3.65
Midstream service expenses ($/BOE)	$0.15
Transportation and marketing expenses ($/BOE)	$0.80
Production and ad valorem taxes (% of oil, NGL and natural gas revenue)	6.25%
General and administrative expenses:	
Cash ($/BOE)	$2.50
Non-cash stock-based compensation ($/BOE)	$1.40
Depletion, depreciation and amortization ($/BOE)	$9.00

Positioned For The Future

APPENDIX

Oil, Natural Gas & Natural Gas Liquids Hedges

Hedge Product Summary	4Q-18	FY-19	FY-20	FY-21
Oil total floor volume (Bbl)	2,398,175	8,687,000	2,196,000	912,500
Oil wtd-avg floor price ($/Bbl)	$47.42	$47.91	$47.27	$45.00
Nat gas total floor volume (MMBtu)	5,983,400			
Nat gas wtd-avg floor price ($/MMBtu)	$2.50			
NGL total floor volume (Bbl)	395,600			

Oil	4Q-18	FY-19	FY-20	FY-21
Puts				
Hedged volume (Bbl)	1,367,775	8,030,000	366,000	
Wtd-avg floor price ($/Bbl)	$51.93	$47.45	$45.00	
Swaps				
Hedged volume (Bbl)		657,000	695,400	
Wtd-avg price ($/Bbl)		$53.45	$52.18	
Collars				
Hedged volume (Bbl)	1,030,400		1,134,600	912,500
Wtd-avg floor price ($/Bbl)	$41.43		$45.00	$45.00
Wtd-avg ceiling price ($/Bbl)	$60.00		$76.13	$71.00

Note: Oil derivatives are settled based on the month's average daily NYMEX index price for the first nearby month of the WTI Light Sweet Crude Oil futures contract

Natural Gas Liquids	4Q-18	FY-19	FY-20	FY-21
Swaps - Ethane				
Hedged volume (Bbl)	156,400			
Wtd-avg price ($/Bbl)	$11.66			
Swaps - Propane				
Hedged volume (Bbl)	128,800			
Wtd-avg price ($/Bbl)	$33.92			
Swaps – Normal Butane				
Hedged volume (Bbl)	46,000			
Wtd-avg price ($/Bbl)	$38.22			
Swaps - Isobutane				
Hedged volume (Bbl)	18,400			
Wtd-avg price ($/Bbl)	$38.33			
Swaps - Natural Gasoline				
Hedged volume (Bbl)	46,000			
Wtd-avg price ($/Bbl)	$57.02			

Note: Natural gas liquids derivatives are settled based on the month's average daily OPIS index price for Mt. Belvieu Purity Ethane and Non-TET: Propane, Normal Butane, Isobutane and Natural Gasoline

Natural Gas - WAHA	4Q-18	FY-19	FY-20	FY-21
Puts				
Hedged volume (MMBtu)	2,055,000			
Wtd-avg floor price ($/MMBtu)	$2.50			
Collars				
Hedged volume (MMBtu)	3,928,400			
Wtd-avg floor price ($/MMBtu)	$2.50			
Wtd-avg ceiling price ($/MMBtu)	$3.35			

Note: Natural gas derivatives are settled based on Inside FERC index price for West Texas WAHA for the calculation period

Basis Swaps	4Q-18	FY-19	FY-20	FY-21
Mid/Cush				
Hedged volume (Bbl)	920,000	552.000		
Wtd-avg price ($/Bbl)	-$0.56	-$4.37		
Hou/Mid				
Hedged volume (Bbl)	920,000	1,810,000		
Wtd-avg price ($/Bbl)	$7.30	$7.30		
Waha/HH				
Hedged volume (MMBtu)	2,300,000	20,075,000	25,254,000	
Wtd-avg price ($/MMBtu)	-$0.62	-$1.05	-$0.76	

Note: Other than the oil basis swaps, the Company's oil derivatives are settled based on the month's average daily NYMEX index price for the first nearby month of the West Texas Intermediate Light Sweet Crude Oil Futures Contract. The oil basis swaps are settled based on either (i) the differential between the Argus Americas Crude West Texas Intermediate ("WTI") index prices for WTI Midland-weighted average for the trade month and WTI Cushing-WTI formula basis for the trade month as compared to the basis swaps' fixed differential price or (ii) the differential between the Argus Americas Crude WTI Houston-weighted average price for the trade month and the WTI Midland-weighted average price for the trade month as compared to the basis swaps' fixed differential price. The Company's NGL derivatives are settled based on the month's average daily OPIS index price for Mont Belvieu Purity Ethane, TET and Non-TET Propane, Non-TET Butane, Non-TET Isobutane and Non-TET Natural Gasoline. Other than the natural gas basis swaps, the Company's natural gas derivatives are settled based on the Inside FERC index price for West Texas WAHA for the calculation period. The natural gas basis swaps are settled based on the differential between the Inside FERC index price for West Texas WAHA for the calculation period and the NYMEX Henry Hub index price for the calculation period as compared to the basis swaps' fixed differential price

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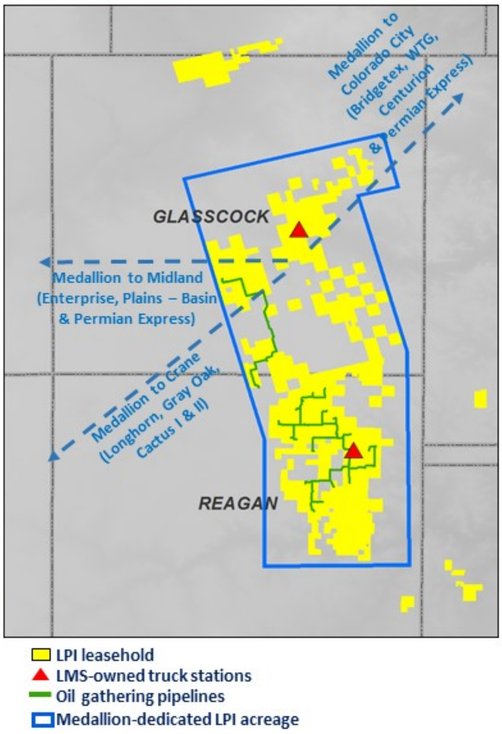
Note: Open positions as of 9/30/2018, hedges executed through 11/5/18

Crude Flow Assurance Supported By LMS & Medallion Infrastructure

- Medallion firm transportation secured for all dedicated-acreage volumes, including expected future growth
- Long-haul connectivity maximized, as Medallion offers delivery optionality to pipelines that connect to Cushing, Houston, Corpus Christi or Nederland markets
- LMS-owned truck stations shorten haults to <20 miles, which increases trucking efficiency and reduces costs

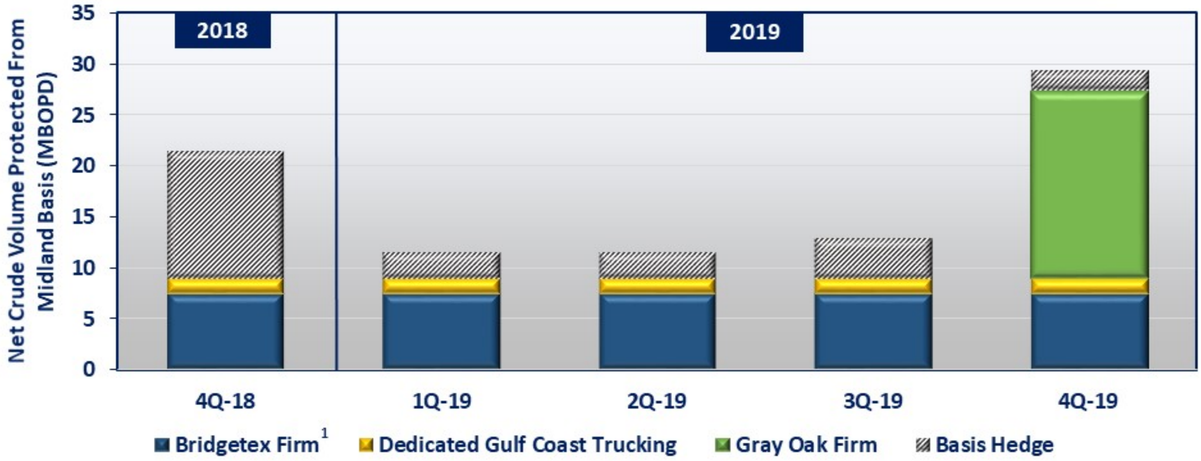
~100% **Firm transportation to long-haul pipes exiting the basin**



LAREDO PETROLEUM

Note: Medallion connections and long-haul pipes on map are either in service or under construction

Oil Value Protected Via Gulf Coast Access & Financial Contracts



Gross Physical Transportation Contracts:

- 10 MBOPD firm transportation on Bridgetex available through 1Q-26
- 2 MBOPD (Sep-18 thru 2019) dedicated trucking arrangement to Gardendale
- Contracted firm transportation on Gray Oak through 4Q-26E
  - Year 1: 25 MBOPD
  - Years 2 - 7: 35 MBOPD

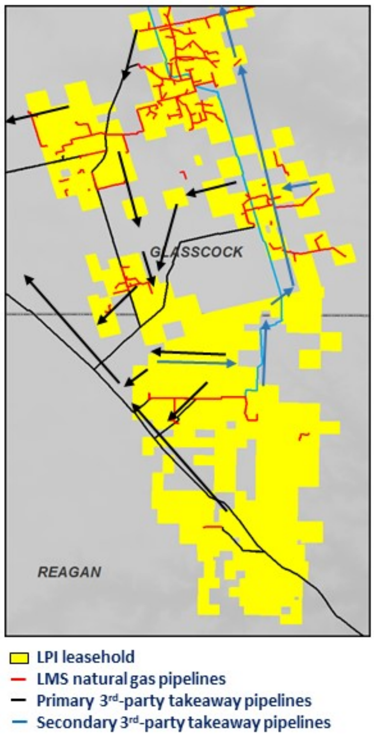
LAREDO PETROLEUM

[1] Hou/Mid Jun-18 - Jun-19 basis swaps lock in gain above Bridgetex firm transport during this time period

Natural Gas Operational Assurance & Value Protection

- LMS assets provide field-level optionality to move production to an alternate purchaser when needed
- Targa processes >90% of LPI's liquids-rich natural gas volumes
- ~70% of 4Q-18 natural gas is protected from a widening Waha basis via Waha product hedges & Waha/HH basis hedges[1]

High confidence in ability to move gas to sales



[1]Hedge percentage assumes updated guidance of ~17% YoY total BOE volume growth from FY-17

Significant Benefits Through Water Infrastructure Investments

Water Infrastructure

- ~110 miles of water gathering & distribution pipelines
- ~75% of produced water gathered by pipe and ~33% of produced water recycled in FY-18E
- 54 MBWPD recycling processing capacity
- 22.5 MMBW owned or contracted storage capacity

>$19 MM

FY-18E net savings generated by LMS water infrastructure investments[1]

[1]Calculated utilizing a 95% WI & 74% NRI
Note: Statistics, estimates and maps as of 9/30/18

Information for Slides 9 & 10

Horizontal drilling in unconventional wells using enhanced completions techniques, including but not limited to hydraulic fracturing, is a relatively new process and, as such, forecasting the long-term production of such wells is inherently uncertain and subject to varying interpretations. As we receive and process geological and production data from these wells over time, we analyze such data to confirm whether previous assumptions regarding original forecasted production and reserves continue to appear accurate, or require modification. While all production forecasts have elements of uncertainty over the life of the related wells, we are seeing indications that the oil portion of such reserves may be less than originally anticipated.

Initial production results, production decline rates, well density, completion design and operating method are examples of the numerous uncertainties and variables inherent in the estimation of proved reserves in future periods. The quantity of proved reserves is one of the many variables inherent in the calculation of depletion. Negative revisions in the estimated quantities of proved reserves have the effect of increasing the rates of depletion on the affected properties, which decreases earnings and increases losses through higher depletion expense. We have experienced increased depletion per BOE sold for each of the last three quarters of 2018.

The table below presents our depletion per BOE sold for the periods presented:

	1Q-18	2Q-18	3Q-18
Depletion per BOE sold..	$ 7.34	$ 7.68	$ 7.94

2018 cumulative production charts include:
- All 59 wells targeting the Company's primary development formations with first production starting in 2018
    - Well count: 59 UWC/MWC normalized to 10,000' as of 10/26/18
- Type curve representative of a weighted average of Laredo's 1.3 MMBOE UWC/MWC

2017 cumulative production charts include:
- All 63 wells targeting the Company's primary development formations with first production starting in 2017
    - Well count: 52 UWC/MWC, 3 LWC & 8 Cline, normalized to 10,000' as of 10/26/18
- Type curve representative of a weighted average of Laredo's 1.3 MMBOE UWC/MWC, 0.9 MMBOE LWC & 1.0 MMBOE Cline type curves

2016 cumulative production charts include:
- All 45 wells targeting the Company's primary development formations with first production starting in 2016
    - Well count: 43 UWC/MWC & 2 Cline, normalized to 10,000' as of 10/26/18
- Type curve representative of a weighted average of Laredo's 1.3 MMBOE UWC/MWC & 1.0 MMBOE Cline type curves

2015 cumulative production charts include:
- All 56 wells targeting the Company's primary development formations with first production starting in 2015
    - Well count: 32 UWC, 9 MWC, 9 LWC & 6 Cline, normalized to 10,000' as of 10/26/18
- Type curve representative of a weighted average of Laredo's 1.1 MMBOE UWC, 1.0 MMBOE MWC, 0.9 MMBOE LWC & 1.0 MMBOE Cline type curves

Supplemental Non-GAAP Financial Measure

Adjusted EBITDA

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

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

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

** On October 30, 2017, LMS, together with Medallion Midstream Holdings, LLC, which is owned and controlled by an affiliate of the third-party interest holder, The Energy & Minerals Group ("EMG"), completed the sale of 100% of the ownership interests in Medallion Gathering & Processing, LLC ("Medallion") to an affiliate of Global Infrastructure Partners ("GIP"), for cash consideration of $1.825 billion (the "Medallion Sale"). LMS' net cash proceeds for its 49% ownership interest in Medallion in 2017 were $829.6 million, before post-closing adjustments and taxes, but after deduction of its proportionate share of fees and other expenses associated with the Medallion Sale. On February 1, 2018, closing adjustments were finalized and LMS received additional net cash of $1.7 million for total net cash proceeds before taxes of $831.3 million. The Medallion Sale closed pursuant to the membership interest purchase and sale agreement, which provides for potential post-closing additional cash consideration that is structured based on GIP's realized profit at exit. There can be no assurance as to when and whether the additional consideration will be paid.

Supplemental Non-GAAP Financial Measure Reconciliation-Continued

(in thousands)		1Q-17	2Q-17	3Q-17	4Q-17	1Q-18	2Q-18	3Q-18
Net income	$	68,276 $	61,110 $	11,027 $	408,561 $	86,520 $	33,452 $	55,050
Plus:								
Income tax expense		-	-	-	1,800	-	-	1,387
Depletion, depreciation and amortization		34,112	38,003	41,212	45,062	45,553	50,762	55,963
Non-cash stock-based compensation, net		9,224	8,687	8,966	8,857	9,339	10,676	8,733
Accretion expense		928	943	951	969	1,106	1,121	1,114
Mark-to-market on derivatives:								
(Gain) loss on derivatives, net		(36,671)	(28,897)	27,441	37,777	(9,010)	45,976	32,245
Settlements (paid) received for matured derivatives, net		7,451	13,705	13,635	2,792	(2,236)	181	(3,888)
Cash settlements received for early terminations of derivatives, net		-	4,234	-	-	-	-	-
Cash premiums paid for derivatives		(2,107)	(9,987)	(1,448)	(12,311)	(4,024)	(5,451)	(5,455)
Interest expense		22,720	23,173	23,697	19,787	13,518	14,424	14,845
Gain on sale of investment in equity method investee**		-	-	-	(405,906)	-	-	-
(Gain) loss on disposal of assets, net		214	(805)	991	906	2,617	1,358	616
Loss on early redemption of debt		-	-	-	23,761	-	-	-
Income from equity method investee		(3,068)	(2,471)	(2,371)	(575)	-	-	-
Proportionate Adjusted EBITDA of equity method investee[1]		6,365	6,601	6,789	2,326	-	-	-
Adjusted EBITDA	$	107,444 $	114,296 $	130,890 $	133,806 $	143,383 $	152,499 $	160,610

[1] Proportionate Adjusted EBITDA of Medallion, our equity method investee until its sale on October 30, 2017, is calculated as follows:

(in thousands)		1Q-17	2Q-17	3Q-17	4Q-17	1Q-18	2Q-18	3Q-18
Income from equity method investee	$	3,068 $	2,471 $	2,371 $	575 $	- $	- $	-
Adjusted for proportionate share of depreciation & amortization		3,297	4,130	4,418	1,751	-	-	-
Proportionate Adjusted EBITDA of equity method investee	$	6,365 $	6,601 $	6,789 $	2,326 $	- $	- $	-