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 7, 2017

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 August 7, 2017, Laredo Petroleum, Inc. (the "Company") announced its financial and operating results for the quarter ended June 30, 2017. Copies of the Company's press release and Presentation (as defined below) are furnished as Exhibit 99.1 and 99.2, respectively, to this Current Report on Form 8-K and are incorporated herein by reference. The Company plans to host a teleconference and webcast on August 8, 2017, at 7:30 am Central Time to discuss these results. To access the call, please dial 1-877-930-8286 or 1-253-336-8309 for international callers, and use conference code 56287044. A replay of the call will be available through Tuesday, August 15, 2017, by dialing 1-855-859-2056, and using conference code 56287044. 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 August 7, 2017, 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 August 7, 2017, 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 August 7, 2017 announcing financial and operating results.
99.2	Presentation dated August 7, 2017.

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.

Date: August 7, 2017	By:	/s/ Richard C. Buterbaugh
		Richard C. Buterbaugh
		Executive Vice President & Chief Financial Officer

EXHIBIT INDEX

Exhibit Number	Description
99.1	Press release dated August 7, 2017 announcing financial and operating results.
99.2	Presentation dated August 7, 2017.

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

Laredo Petroleum Announces 2017 Second-Quarter Financial and Operating Results

Raises Estimated 2017 Production Growth to 16% - 19%

TULSA, OK - August 7, 2017 - Laredo Petroleum, Inc. (NYSE: LPI) ("Laredo" or "the Company") today announced its 2017 second-quarter results, reporting net income attributable to common stockholders of $61.1 million, or $0.25 per diluted share. Adjusted Net Income, a non-GAAP financial measure, for the second quarter of 2017 was $25.2 million, or $0.10 per adjusted diluted share. Adjusted EBITDA, a non-GAAP financial measure, for the second quarter of 2017 was $114.3 million. Please see supplemental financial information at the end of this news release for reconciliations of non-GAAP financial measures.

2017 Second-Quarter Highlights

- Produced a Company record 58,632 barrels of oil equivalent ("BOE") per day, an increase of approximately 23% from the second quarter of 2016 and up 12% from first-quarter 2017
- Grew oil production to a Company record 27,275 barrels of oil per day, an increase of approximately 16% from the first quarter of 2017
- Increased anticipated production growth for full-year 2017 to a range of 16% - 19% from 2016 with no change to the 2017 capital budget of $530 million
- Reduced unit lease operating expenses ("LOE") approximately 15% to $3.77 per BOE from the second-quarter 2016 rate of $4.43 per BOE
- Recognized approximately $7.0 million in cash benefits from Laredo Midstream Services, LLC ("LMS") field infrastructure investments through reduced costs and increased revenue

"In the second quarter, Laredo continued to create value for shareholders, adding more than 6,000 BOE per day of production from the rate in the first quarter of 2017," commented Randy A. Foutch, Chairman and Chief Executive Officer. "Our early decision to invest in acquiring high-quality data facilitated the development of proprietary workflows utilizing big data analytics that are powering our modeling efforts, shortening the time from concept to implementation. These efforts have increased well productivity, contributing to our increase in full-year 2017 production guidance. The productivity gains, coupled with the low operating costs facilitated by our investments in infrastructure and production corridors, are driving continued increases in capital efficiency that are expected to sustain our high-return drilling program."

Operational Update

In the second quarter of 2017, Laredo produced a Company record 58,632 BOE per day, completing 16 horizontal wells with an average completed lateral length of approximately 9,100 feet. Well productivity continues to improve as the Company refines its proprietary technology workflows and data analytics to improve landing point selection and individual well completion design. Driven by the improving performance, Laredo is increasing its expected 2017 year-over-year production growth rate to a range of 16% - 19%.

Second-quarter 2017 production was positively impacted by the nine-well JL McMaster-Bodine package, which was completed late in the first quarter of 2017 and utilized Laredo's customized managed flowback procedure. This package is currently outperforming Laredo's Upper/Middle Wolfcamp three-stream type curve by 45% and outperforming the Company's oil type curve by 41%.

Wells on managed flowback initially produce less than those not on managed flowback, but the production deficit is overcome in less than 90 days, on average. Longer-term production data is positive, with wells on Laredo's managed flowback generating first-year cumulative production approximately 5% - 10% higher than non-managed flowback wells. Laredo expects to continue utilizing managed flowback on all newly completed wells and will continue to monitor production data to assess the long-term impact on well performance.

Laredo completed the last six wells of the nine-well Sugg-Graham package in the second quarter of 2017. While early in its production history, this package is currently outperforming the Company's Upper/Middle Wolfcamp three-stream type curve by 24% and outperforming the oil type curve by 25%. Importantly, this package supports tighter spacing between landing points, in a chevroned pattern, between wells at the bottom of the Upper Wolfcamp and top of the Middle Wolfcamp. Tighter vertical spacing between the landing points is one step in the process of testing several landing points for co-development in both the Upper and Middle Wolfcamp formations, which, if successful, will significantly add to the Company's premium Upper and Middle Wolfcamp inventory.

The Company continues to apply in-house technology and data analytics to optimize completion design in relation to well spacing and the co-development of landing points within the Upper and Middle Wolfcamp formations. Individual completion design variables such as perf cluster spacing, clusters per stage, proppant density, sand size, precise landing point selection and well spacing configuration are being tested in all of the Company's well packages. During the second quarter of 2017, Laredo spudded a six-well package on its Western Glasscock production corridor that will test the potential co-development of multiple landing points within the Upper Wolfcamp formation. This test of three landing points in the Upper Wolfcamp will, if successful, increase premium Upper Wolfcamp inventory.

A component of Laredo's completion optimization testing is assessing the productivity and economics of higher proppant concentrations. Utilizing the Company's proprietary models to optimize proppant density and completion design led to internal predictions of production uplift of approximately 50% above type curve. Laredo quickly moved to implement the modeled designs in the field. Currently, the Company has completed 13 wells utilizing a combination of tests of tighter perf cluster spacing, precise landing point selection, sand size, well density, and managed flowback, in concert with increased proppant density of 2,400 pounds of proppant per lateral foot. This group of wells is currently outperforming Laredo's Upper and Middle Wolfcamp type curve by approximately 46%. The Company is very encouraged by these results and will continue to evaluate the economics of these variables coupled with higher proppant density.

In the third quarter of 2017, Laredo expects to complete 15 wells with an average lateral length of approximately 9,900 feet. As testing of 15 and 30-foot perf cluster spacing has improved well productivity, the Company expects to accelerate further testing in the second half of 2017. Tighter perf cluster spacing slightly increases cycle-time per well and Laredo now expects to complete approximately 60 - 65 horizontal wells in 2017.

Unit lease operating expenses decreased approximately 15% from the second quarter of 2016 to $3.77 per BOE. This is the fourth consecutive quarter in which unit LOE's were below $4.00 per BOE, driven by Laredo's previous field infrastructure investments.

Laredo Midstream Services Update

Field infrastructure owned by LMS provided significant financial and operating benefits in the second quarter of 2017. Total revenue and cost savings benefits were $7.0 million, driven by gathering on pipe 82% of Laredo's gross operated oil production and 73% of total produced water.

The Company's production corridors are key to operational efficiency and low operating costs. LOE savings in the second quarter of 2017 from reduced trucking of produced water, recycling of produced water and centralized compression facilities resulted in unit LOE reductions of $0.60 per BOE.

2017 Capital Program

During the second quarter of 2017, Laredo invested approximately $123 million in exploration and development activities. Other expenditures incurred during the quarter included approximately $3 million in bolt-on land acquisitions and lease extensions, approximately $6 million in infrastructure held by LMS and approximately $6 million in capitalized employee-related costs.

Through the first half of 2017, base well costs for 10,000-foot horizontal wells completed with 1,800 pounds of sand per lateral foot and 54-foot perf cluster spacing have been within Laredo's budgeted well cost expectations. The Company's $530 million capital budget is unchanged, although upward pressure in service costs, if sustained throughout the remainder of the year, could result in a 5% - 10% increase in the full-year 2017 capital budget.

Liquidity

At June 30, 2017, the Company had cash and cash equivalents of approximately $35 million and undrawn capacity under the senior secured credit facility of $895 million, resulting in total liquidity of approximately $930 million. At August 4, 2017, the Company had cash and equivalents of approximately $12 million and available capacity under the senior secured credit facility of $885 million, resulting in total available liquidity of approximately $900 million.

Commodity Derivatives

Laredo maintains a disciplined hedging program to reduce the variability in its anticipated cash flow due to fluctuations in commodity prices. At June 30, 2017, the Company had hedges in place for the remaining two quarters of 2017 for 3,454,600 barrels of oil at a weighted-average floor price of $55.82 per barrel.

The Company also had hedges in place for the remaining two quarters of 2017 for 13,606,400 million British thermal units ("MMBtu") of natural gas at a weighted-average floor price of $2.75 per MMBtu. All natural gas hedges the Company has in place are priced at the WAHA hub. Additionally, Laredo had hedged 222,000 barrels of ethane at $11.24 per barrel and 187,500 barrels of propane at $22.26 per barrel.

At June 30, 2017, for 2018, the Company had hedged 6,704,875 barrels of oil at a weighted-average floor price of $46.34 per barrel. All hedged oil volumes in 2018 are structured to retain upside to an increase in oil price. Puts on approximately 2.6 million barrels of oil retain unlimited upside and collars on approximately 4.1 million barrels have a $60.00 per barrel ceiling.

The Company also had hedges in place for 2018 for 23,805,500 MMBtu of natural gas at a weighted-average floor price of $2.50 per MMBtu, priced at the WAHA hub.

Guidance

The Company is increasing its anticipated full-year 2017 production growth guidance to a range of 16% - 19% as compared to 2016. The table below reflects the Company’s production guidance for the third and fourth quarters of 2017 and cost guidance for the third quarter of 2017:

	3Q-2017	**4Q-2017**
Production (MBOE/d)	59 - 62	61 - 64
Product % of total production:		
Crude oil	45% - 47%	45% - 47%
Natural gas liquids	26% - 27%	*
Natural gas	27% - 28%	*
Price Realizations (pre-hedge):		
Crude oil (% of WTI)	~88%	*
Natural gas liquids (% of WTI)	~31%	*
Natural gas (% of Henry Hub)	~69%	*
Operating Costs & Expenses:		
Lease operating expenses ($/BOE)	$3.60 - $4.00	*
Midstream expenses ($/BOE)	$0.20 - $0.30	*
Production and ad valorem taxes (% of oil, NGL and natural gas revenue)	6.25%	*
General and administrative expenses:		
Cash ($/BOE)	$2.50 - $3.00	*
Non-cash stock-based compensation ($/BOE)	$1.50 - $1.75	*
Depletion, depreciation and amortization ($/BOE)	$7.00 - $7.50	*

** Not provided*

Conference Call Details

On Tuesday, August 8, 2017, at 7:30 a.m. CT, Laredo will host a conference call to discuss its second-quarter 2017 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 56287044, approximately 10 minutes prior to the scheduled conference time. International participants should dial 253.336.8309, also using conference code 56287044. A telephonic replay will be available approximately two hours after the call on August 8, 2017 through Tuesday, August 15, 2017. Participants may access this replay by dialing 855.859.2056, using conference code 56287044.

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 the gathering of oil and liquids-rich natural gas from such properties, 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, and other factors, including those and other risks described in its Annual Report on Form 10-K for the year ended December 31, 2016, 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.

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, drilling costs and production costs, availability 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 unproved 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 June 30, 2017	Three months ended June 30, 2016	Six months ended June 30, 2017	Six months ended June 30, 2016
	(unaudited)		(unaudited)	
Revenues:				
Oil, NGL and natural gas sales	$ 141,837	$ 102,526	$ 280,573	$ 175,668
Midstream service revenues	2,703	1,632	5,702	3,433
Sales of purchased oil	42,461	42,615	89,732	74,229
Total revenues	187,001	146,773	376,007	253,330
Costs and expenses:				
Lease operating expenses	20,104	19,225	37,096	39,743
Production and ad valorem taxes	8,472	7,982	17,253	14,417
Midstream service expenses	896	1,178	1,812	1,787
Costs of purchased oil	44,020	44,012	94,276	76,958
General and administrative	22,008	20,502	47,605	39,953
Depletion, depreciation and amortization	38,003	34,177	72,115	75,655
Impairment expense	—	963	—	162,027
Other operating expenses	1,437	860	2,463	1,704
Total costs and expenses	134,940	128,899	272,620	412,244
Operating income (loss)	52,061	17,874	103,387	(158,914)
Non-operating income (expense):				
Gain (loss) on derivatives, net	28,897	(68,518)	65,568	(50,633)
Income from equity method investee	2,471	3,696	5,539	5,994
Interest expense	(23,173)	(23,512)	(45,893)	(47,217)
Other, net	854	(972)	785	(1,033)
Non-operating income (expense), net	9,049	(89,306)	25,999	(92,889)
Income (loss) before income taxes	61,110	(71,432)	129,386	(251,803)
Income tax:				
Deferred	—	—	—	—
Total income tax	—	—	—	—
Net income (loss)	$ 61,110	$ (71,432)	$ 129,386	$ (251,803)
Net income (loss) per common share:				
Basic	$ 0.26	$ (0.33)	$ 0.54	$ (1.17)
Diluted	$ 0.25	$ (0.33)	$ 0.53	$ (1.17)
Weighted-average common shares outstanding:				
Basic	239,231	217,564	238,870	214,562
Diluted	244,417	217,564	244,385	214,562

Laredo Petroleum, Inc.
Condensed consolidated balance sheets

(in thousands)	June 30, 2017	December 31, 2016
	(unaudited)	(unaudited)
Assets:		
Current assets	$ 167,664	$ 154,777
Property and equipment, net	1,499,286	1,366,867
Other noncurrent assets	274,304	260,702
Total assets	$ 1,941,254	$ 1,782,346
Liabilities and stockholders' equity:		
Current liabilities	$ 172,083	$ 187,945
Long-term debt, net	1,390,277	1,353,909
Other noncurrent liabilities	54,491	59,919
Stockholders' equity	324,403	180,573
Total liabilities and stockholders' equity	$ 1,941,254	$ 1,782,346

Laredo Petroleum, Inc.
Condensed consolidated statements of cash flows

(in thousands)	Three months ended June 30, 2017	Three months ended June 30, 2016	Six months ended June 30, 2017	Six months ended June 30, 2016
	(unaudited)		(unaudited)	
Cash flows from operating activities:				
Net income (loss)	$ 61,110	$ (71,432)	$ 129,386	$ (251,803)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Depletion, depreciation and amortization	38,003	34,177	72,115	75,655
Impairment expense	—	963	—	162,027
Non-cash stock-based compensation, net of amounts capitalized	8,687	6,073	17,911	9,911
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	(28,897)	68,518	(65,568)	50,633
Cash settlements received for matured derivatives, net	13,705	47,382	21,156	113,319
Cash settlements received for early terminations of derivatives, net	4,234	—	4,234	80,000
Cash premiums paid for derivatives	(9,987)	(2,413)	(12,094)	(84,263)
Other, net	(1,158)	(723)	(1,920)	(7,217)
Cash flows from operations before changes in working capital and other noncurrent liabilities	85,697	82,545	165,220	148,262
Increase (decrease) in working capital	7,541	(304)	(8,154)	(9,435)
Decrease in other noncurrent liabilities	(121)	(127)	(165)	(196)
Net cash provided by operating activities	93,117	82,114	156,901	138,631
Cash flows from investing activities:				
Capital expenditures:				
Oil and natural gas properties	(121,677)	(91,887)	(232,219)	(197,042)
Midstream service assets	(4,386)	(1,488)	(6,117)	(3,425)
Other fixed assets	(1,480)	(202)	(2,683)	(832)
Investment in equity method investee	—	(16,021)	—	(42,681)
Proceeds from dispositions of capital assets, net of selling costs	3,926	132	63,441	350
Net cash used in investing activities	(123,617)	(109,466)	(177,578)	(243,630)
Cash flows from financing activities:				
Borrowings on Senior Secured Credit Facility	40,000	35,000	90,000	120,000
Payments on Senior Secured Credit Facility	—	(119,682)	(55,000)	(144,682)
Proceeds from issuance of common stock, net of offering costs	—	119,310	—	119,310
Other, net	(4,828)	(62)	(11,971)	(1,474)
Net cash provided by financing activities	35,172	34,566	23,029	93,154
Net increase (decrease) in cash and cash equivalents	4,672	7,214	2,352	(11,845)
Cash and cash equivalents, beginning of period	30,352	12,095	32,672	31,154
Cash and cash equivalents, end of period	$ 35,024	$ 19,309	$ 35,024	$ 19,309

Laredo Petroleum, Inc.
Selected operating data

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
	(unaudited)		(unaudited)	
Sales volumes:				
Oil (MBbl)	2,482	2,012	4,602	4,018
NGL (MBbl)	1,433	1,153	2,696	2,219
Natural gas (MMcf)	8,524	7,038	16,524	13,834
Oil equivalents (MBOE)[1][2]	5,336	4,338	10,052	8,542
Average daily sales volumes (BOE/D)[1]	58,632	47,667	55,536	46,935
% Oil	47%	46%	46%	47%
Average sales prices[1]:				
Oil, realized ($/Bbl)[3]	$ 42.00	$ 39.37	$ 44.26	$ 33.45
NGL, realized ($/Bbl)[3]	$ 13.82	$ 12.24	$ 15.07	$ 10.44
Natural gas, realized ($/Mcf)[3]	$ 2.09	$ 1.31	$ 2.19	$ 1.31
Average price, realized ($/BOE)[3]	$ 26.58	$ 23.64	$ 27.91	$ 20.56
Oil, hedged ($/Bbl)[4]	$ 46.95	$ 58.86	$ 48.22	$ 57.85
NGL, hedged ($/Bbl)[4]	$ 13.61	$ 12.24	$ 14.75	$ 10.44
Natural gas, hedged ($/Mcf)[4]	$ 2.12	$ 2.13	$ 2.21	$ 2.10
Average price, hedged ($/BOE)[4]	$ 28.88	$ 34.00	$ 29.66	$ 33.33
Average costs per BOE sold[1]:				
Lease operating expenses	$ 3.77	$ 4.43	$ 3.69	$ 4.65
Production and ad valorem taxes	1.59	1.84	1.72	1.69
Midstream service expenses	0.17	0.27	0.18	0.21
General and administrative:				
Cash	2.50	3.33	2.95	3.52
Non-cash stock-based compensation, net of amounts capitalized	1.63	1.40	1.78	1.16
Depletion, depreciation and amortization	7.12	7.88	7.17	8.86
Total	$ 16.78	$ 19.15	$ 17.49	$ 20.09

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

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

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

(4) Hedged prices reflect the after-effect of our hedging transactions on our average sales prices. Our calculation of such after-effects includes current period settlements of matured derivatives in accordance with GAAP and an adjustment to reflect premiums incurred previously or upon settlement that are attributable to instruments that settled in the period.

Laredo Petroleum, Inc.
Costs incurred

Costs incurred in the acquisition, exploration and development of oil, NGL and natural gas assets are presented below:

	Three months ended June 30,		Six months ended June 30,	
(in thousands)	**2017**	**2016**	**2017**	**2016**
	(unaudited)		(unaudited)	
Property acquisition costs:				
Evaluated	$ —	$ —	$ —	$ —
Unevaluated	—	—	—	—
Exploration costs	5,658	19,769	21,201	27,032
Development costs[(1)]	125,738	70,806	236,896	152,692
Total costs incurred	$ 131,396	$ 90,575	$ 258,097	$ 179,724

(1) Development costs include $0.1 million in asset retirement obligations for each of the three months ended June 30, 2017 and 2016, and $0.2 million for each of the six months ended June 30, 2017 and 2016.

Laredo Petroleum, Inc.
Supplemental reconciliation 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 flow from operating activities. Adjusted Net Income or Adjusted EBITDA should not be considered in isolation or as a substitute for GAAP measures, such as net income or loss, operating income or loss or any other GAAP measure of liquidity or financial performance.

Adjusted Net Income (Unaudited)

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

Including a higher weighted-average shares outstanding in the denominator of a diluted per-share computation results in an anti-dilutive per share amount when an entity is in a loss position. As such, for the three and six months ended June 30, 2016, our net loss (GAAP) per common share calculation utilizes the same denominator for both basic and diluted net loss per common share. However, our calculation of Adjusted Net Income (non-GAAP) results in income for both periods presented. Therefore, we believe it appropriate and more conservative to calculate an Adjusted diluted weighted-average common shares outstanding utilizing our fully dilutive weighted-average common shares. As such, for each of the three and six months ended June 30, 2017 and 2016, we present a line item that calculates Adjusted Net Income per Adjusted diluted common share. This line item was not presented in the prior periods.

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

	Three months ended June 30,		Six months ended June 30,	
(in thousands, except per share data, unaudited)	2017	2016	2017	2016
Net income (loss)	$ 61,110	$ (71,432)	$ 129,386	$ (251,803)
Plus:				
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	(28,897)	68,518	(65,568)	50,633
Cash settlements received for matured derivatives, net	13,705	47,382	21,156	113,319
Cash settlements received for early terminations of derivatives, net	4,234	—	4,234	80,000
Cash premiums paid for derivatives	(9,987)	(2,413)	(12,094)	(84,263)
Impairment expense	—	963	—	162,027
(Gain) loss on disposal of assets, net	(805)	141	(591)	301
Write-off of debt issuance costs	—	842	—	842
Adjusted net income before adjusted income tax expense	39,360	44,001	76,523	71,056
Adjusted income tax expense	(14,170)	(15,840)	(27,548)	(25,580)
Adjusted Net Income	$ 25,190	$ 28,161	$ 48,975	$ 45,476
Net income (loss) per common share:				
Basic	$ 0.26	$ (0.33)	$ 0.54	$ (1.17)
Diluted	$ 0.25	$ (0.33)	$ 0.53	$ (1.17)
Adjusted Net Income per common share:				
Basic	$ 0.11	$ 0.13	$ 0.21	$ 0.21
Adjusted diluted	$ 0.10	$ 0.13	$ 0.20	$ 0.21
Weighted-average common shares outstanding:				
Basic	239,231	217,564	238,870	214,562
Diluted	244,417	217,564	244,385	214,562
Adjusted diluted	244,417	222,032	244,385	218,122

Adjusted EBITDA (Unaudited)

Adjusted EBITDA is a non-GAAP financial measure that we define as net income or loss plus adjustments for deferred income tax expense or benefit, depletion, depreciation and amortization, impairment expense, non-cash stock-based compensation, net of amounts capitalized, accretion expense, mark-to-market on derivatives, cash premiums paid for derivatives, interest expense, write-off of debt issuance costs, 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 and 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, 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.

During the year ended December 31, 2016, we changed the methodology for calculating Adjusted EBITDA by including adjustments for both accretion of asset retirement obligations and our proportionate share of our equity method investee's Adjusted EBITDA. Accordingly, the prior period's Adjusted EBITDA has been modified for comparability.

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

	Three months ended June 30,		Six months ended June 30,	
(in thousands, unaudited)	**2017**	**2016**	**2017**	**2016**
Net income (loss)	$ 61,110	$ (71,432)	$ 129,386	$ (251,803)
Plus:				
Depletion, depreciation and amortization	38,003	34,177	72,115	75,655
Impairment expense	—	963	—	162,027
Non-cash stock-based compensation, net of amounts capitalized	8,687	6,073	17,911	9,911
Accretion expense	943	860	1,871	1,704
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	(28,897)	68,518	(65,568)	50,633
Cash settlements received for matured derivatives, net	13,705	47,382	21,156	113,319
Cash settlements received for early terminations of derivatives, net	4,234	—	4,234	80,000
Cash premiums paid for derivatives	(9,987)	(2,413)	(12,094)	(84,263)
Interest expense	23,173	23,512	45,893	47,217
Write-off of debt issuance costs	—	842	—	842
(Gain) loss on disposal of assets, net	(805)	141	(591)	301
Income from equity method investee	(2,471)	(3,696)	(5,539)	(5,994)
Proportionate Adjusted EBITDA of equity method investee[1]	6,601	5,103	12,966	8,787
Adjusted EBITDA	$ 114,296	$ 110,030	$ 221,740	$ 208,336

(1) Proportionate Adjusted EBITDA of Medallion, our equity method investee, is calculated as follows:

	Three months ended June 30,		Six months ended June 30,	
(in thousands, unaudited)	**2017**	**2016**	**2017**	**2016**
Income from equity method investee	$ 2,471	$ 3,696	$ 5,539	$ 5,994
Adjusted for proportionate share of:				
Depreciation and amortization	4,130	1,407	7,427	2,793
Proportionate Adjusted EBITDA of equity method investee	$ 6,601	$ 5,103	$ 12,966	$ 8,787

# # #

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EXHIBIT 99.2

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, hedging activities, capital expenditure levels 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 and the related impact to financial statements as a result of asset impairments and revisions to reserve estimates, availability and cost of drilling equipment and personnel, availability of sufficient capital to execute the Company's business plan, impact of compliance with legislation and regulations, 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, 2016 and other reports filed with the Securities 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 to disclose proved reserves in filings made with the SEC, 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," "horizontal productivity confirmed," "horizontal productivity not confirmed" 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 that may be ultimately recovered from the Company's interests are unknown. Factors affecting ultimate recovery include the scope of the Company's ongoing drilling program, which will be directly affected by the availability of capital, drilling and production costs, availability and cost of drilling services and equipment, lease expirations, transportation constraints, regulatory approvals 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 provide additional data. 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.

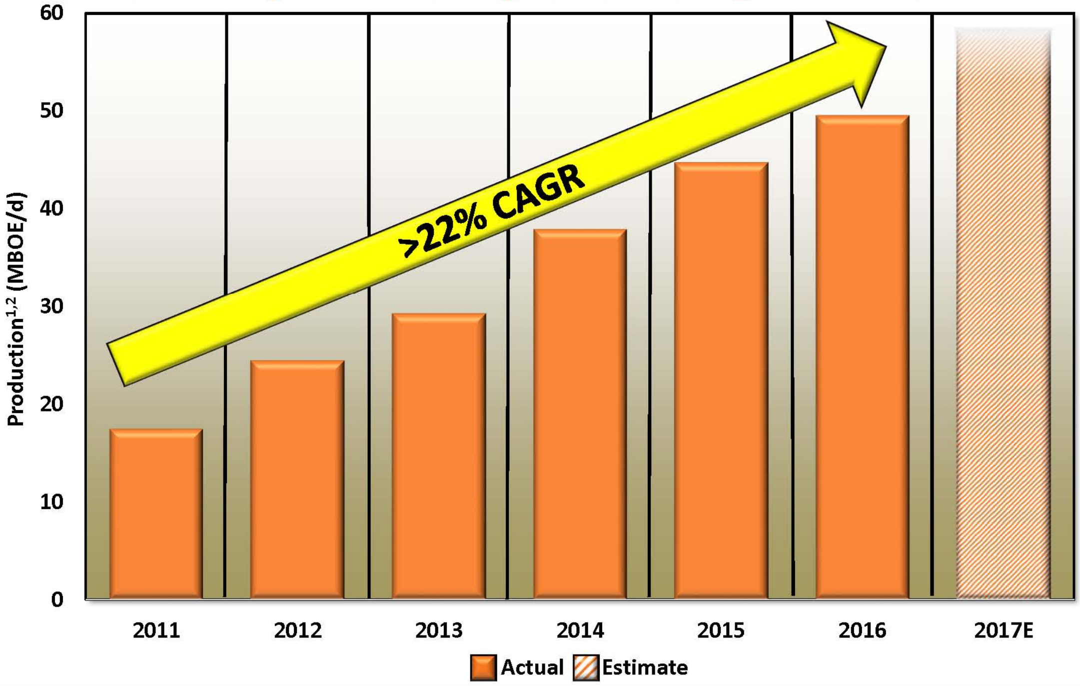
This presentation includes financial measures that are not in accordance with generally accepted accounting principles ("GAAP"), including Adjusted EBITDA. While management believes that such measures are useful for investors, they should not be used as a replacement for financial measures that are in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

2Q-17 Highlights

- Produced a Company record 58,632 BOE/d, an increase of ~23% from 2Q-16 and 12% from 1Q-17
- Grew oil production to a Company record 27,275 BO/d, an increase of ~16% from 1Q-17
- Increased anticipated production growth for FY-17 to a range of 16% - 19% with no change to the 2017 capital budget of $530 MM
- Reduced unit LOE ~15% to $3.77/BOE from the 2Q-16 rate of $4.43/BOE
- Recognized ~$7.0 MM in cash benefits from LMS field infrastructure investments in 2Q-17 through reduced costs and increased revenue

Consistent Production Growth

Increased anticipated 2017 production growth to 16% - 19%



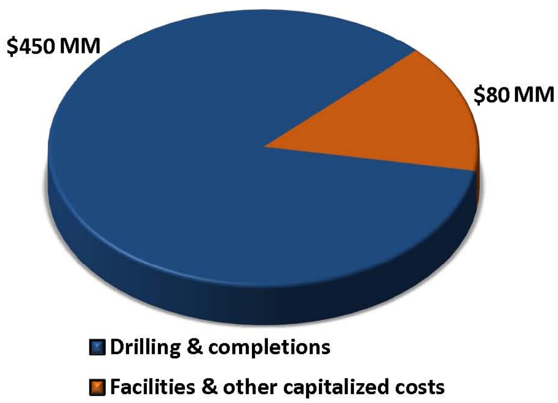
Note: 2017 estimated production is utilizing the midpoint of 16% - 19% of production guidance

[1] Production numbers prior to 2014 have been converted to 3-stream using an 18% uplift. 2014 results have been converted to 3-stream using actual gas plant economics

[2] 2011 - 2013 adjusted for Granite Wash divestiture, closed August 1, 2013

2017 Capital and Operating Expectations

2017 Capital Budget[1]
$530 MM



2017 Drilling & Completions

- Operating 4 Hz rigs
- Drilling and completing 60 - 65 Hz wells
- Lateral length expected to average ~10,000’
- Developed as packages to mitigate parent-child impact
- Testing co-development of multiple landing points in UWC/MWC formations

Maintaining capital budget while increasing FY-17E YoY production growth range to 16% - 19%

[1] Does not include acquisitions or investments in Medallion-Midland Basin system
Note: Capital budget is unchanged, although upward pressure in service costs, if sustained throughout the remainder of the year, could result in a 5% - 10% increase in the FY-17 capital budget

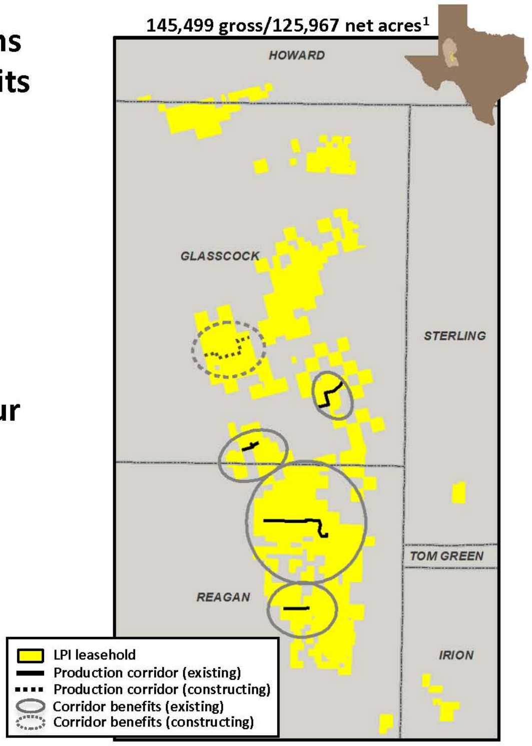
Capitalizing on Contiguous Acreage Position

- The company has identified >2,000 locations that support lateral lengths of 10,000'+ on its contiguous acreage

- Centralized infrastructure in multiple production corridors and the ability to drill long laterals enable increased capital and operational efficiencies
  - Infrastructure benefits have facilitated unit LOE costs below $4.00/BOE for four consecutive quarters

~85% of acreage HBP[1], enabling a concentrated development plan along production corridors

145,499 gross/125,967 net acres[1]



[1] As of 6/30/17

Multiple Targeted Horizons

2017 Drilling Targets

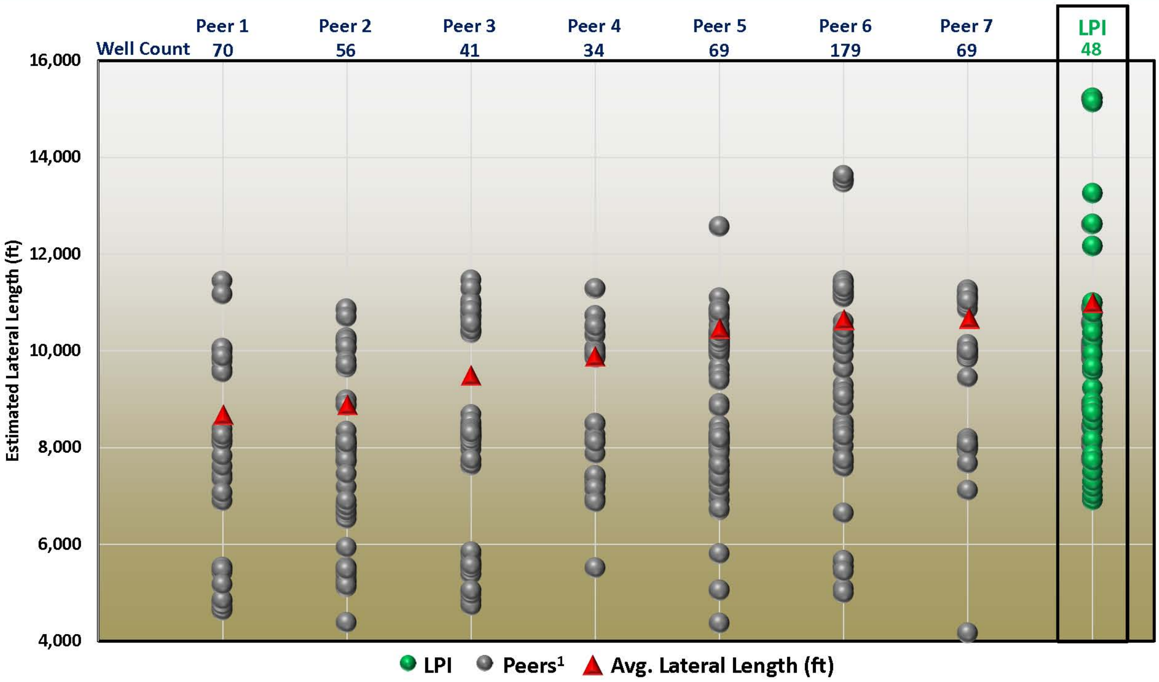
4,500 gross ft. of prospective zones

	Hz Wells Drilled	Thickness	3 Stream (STMMBOE)[1]	Identified Landing Points
Clearfork				
Upper/Middle Spraberry				
Lower Spraberry	2	~415'	90	2 - 3
Dean				
Upper Wolfcamp	133	~405'	72	2 - 3
Middle Wolfcamp	79	~620'	69	2 - 3
Lower Wolfcamp	30	~520'	69	1
Canyon	2	~470'	40	1
Penn Shale				
Cline	62	~330'	47	2
Strawn	2	~75'	n/a	1
Atoka, Barnett, Woodford	1	~375'	41	1

[1] Representative of the estimated mean 3 stream (STMMBOE) per section, measured in stock tank million barrels of oil equivalent
Note: As of 6/30/17

LAREDO PETROLEUM

Peer-Leading Long-Lateral Execution



Contiguous acreage position supports capital-efficient, long-lateral development

[1] Peers: Callon, Diamondback, Encana, Energen, Parsley, Pioneer & RSP Permian

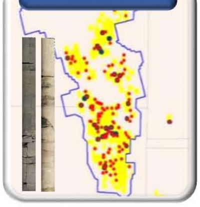
Note: Data is from IHS Enerdeq for the period of 07/01/2016 – 6/30/2017 for Glasscock, Howard, Irion, Midland, Reagan and Martin & Upton counties, TX wells with lateral length greater than 4,000'

Proprietary Modeling Accelerates Value Creation

Proprietary workflow accelerates the process of advancing concepts to implementation

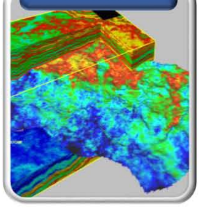
Extensive, High-Quality Data + In-House Technology Development = Increased Value

Active Data Acquisition



Seismic Logs & Core Data

Earth Model Analytics

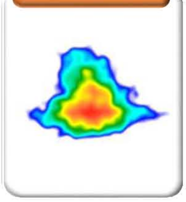


3D Attributes

Proprietary Completions Simulation

Pre-Drill Geometries

Field Testing of Internal Theories



Geometries During Completion

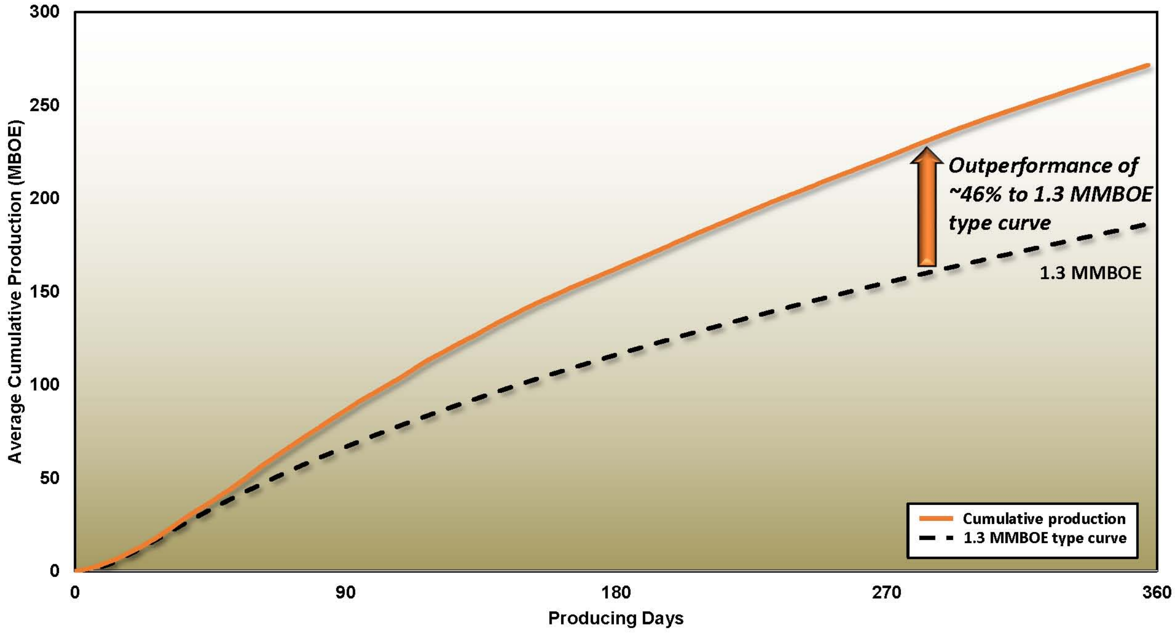
NAV-Maximized Development

Geomodel Oil Saturation

Strategic Testing Leading to High-Density Development				
Big Data	Predictive Analytics	Internal Forward Frac Modeling	Field Testing of NAV-Accretive Theories	Multi-Zone Co-Development

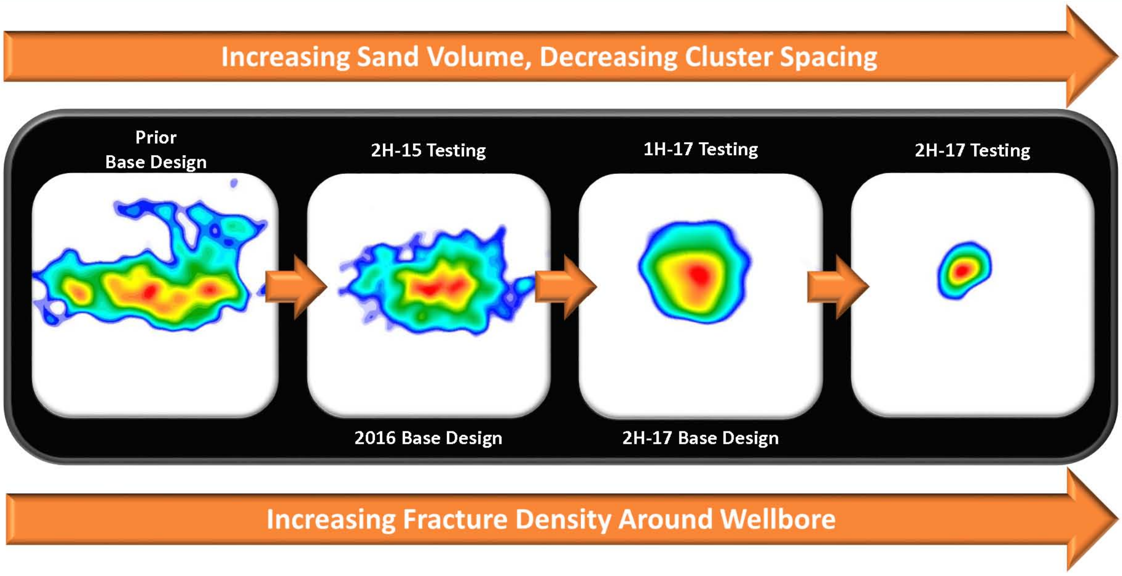
An Example of Field Tests Confirming Internal Models

Initial models predicted ~50% improvement to type curve when utilizing 2,400 lb/ft completions. Actual field tests are confirming our internal models



[1] Average cumulative production data through 7/31/17. This includes 13 Hz UWC/MWC wells that have utilized optimized completions with avg. 2,400 lb/ft sand
Note: Production has been scaled to 10,000' EUR type curves and non-producing days (for shut-ins) have been removed

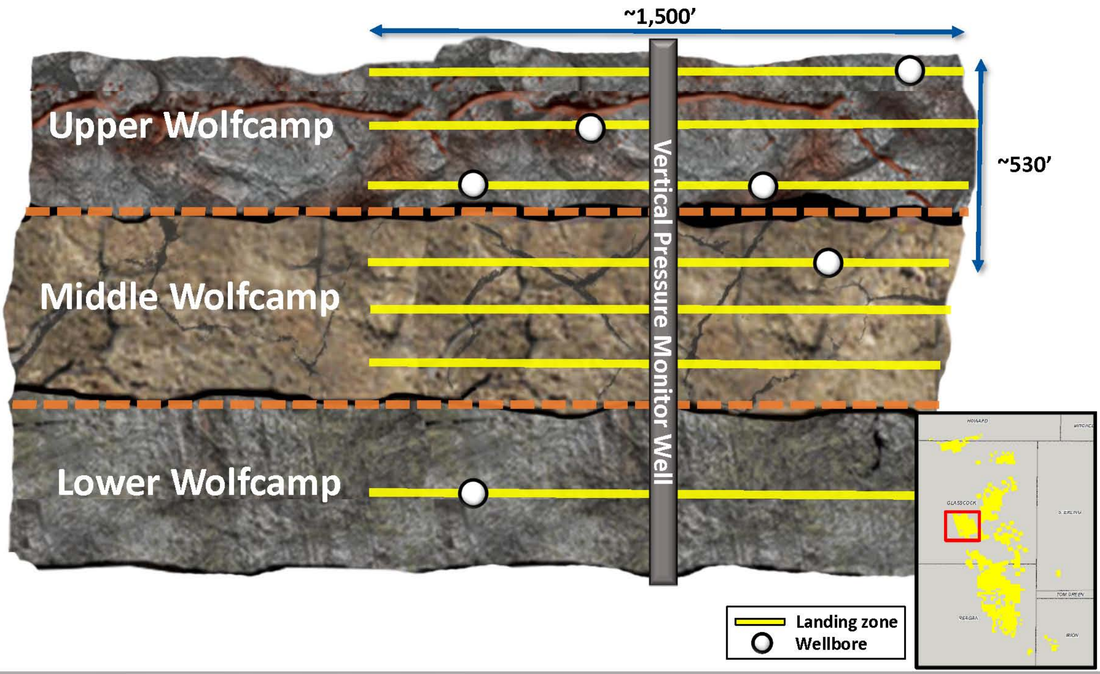
Internal Models Accelerate Completions Design Evolution



Internal modeling efforts are shortening time from concept to field implementation, enabling continual optimization of completions designs

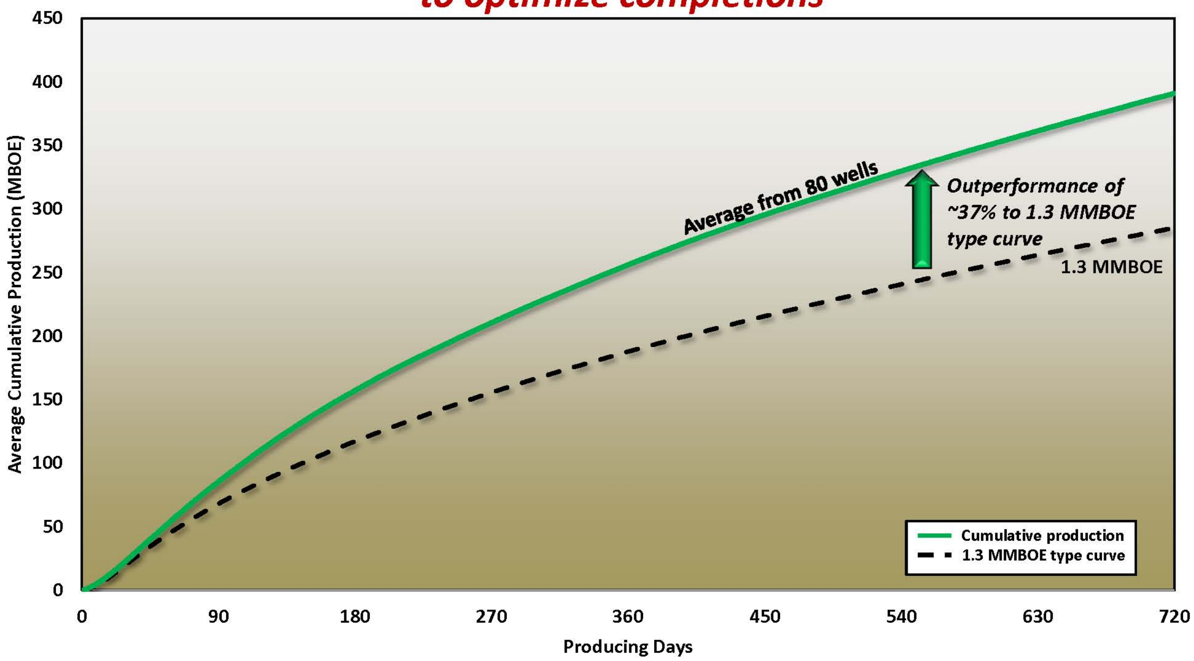
Testing Co-Development of Landing Points

Potential to add additional high-value inventory in the UWC formation



Proprietary Workflows Deliver Well Productivity Improvements

Dataset includes all 80 wells utilizing proprietary models to optimize completions

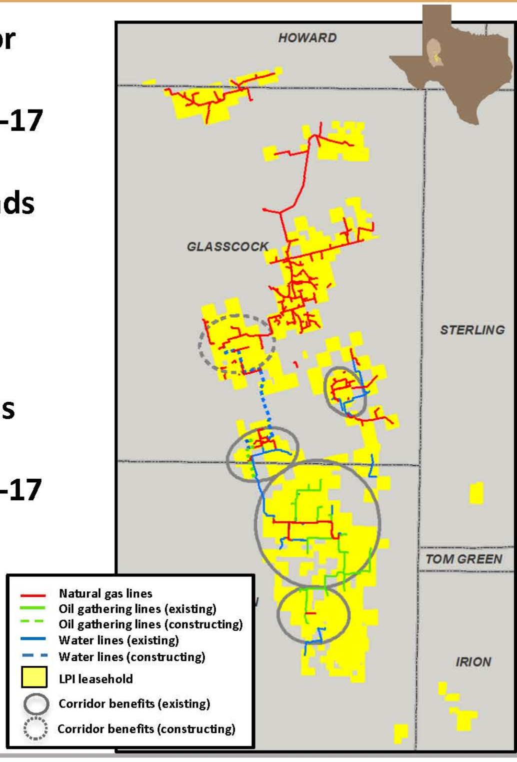


[1] Average cumulative production data through 7/31/17. This includes 80 Hz UWC/MWC & Cline wells that have utilized optimized completions with avg. ~1,900 lb/ft sand
Note: Production has been scaled to 10,000' EUR type curves and non-producing days (for shut-ins) have been removed

Prior Investments in Infrastructure Providing Tangible Benefits

- **Expect to receive \$28.4 MM total benefits for 2017[1]**
  - **~\$7.0 MM total benefits received in 2Q-17**
- **Anticipate reducing >100,000 water truckloads in 2017[1]**
  - **Eliminated ~32,000 water truckloads in 2Q-17**
- **Anticipate reducing ~65,000 crude truckloads in 2017[1]**
  - **Eliminated ~16,000 oil truckloads in 2Q-17**

In 2Q-17, Laredo's infrastructure assets gathered on pipe 82% of gross operated oil production & 73% of total produced water

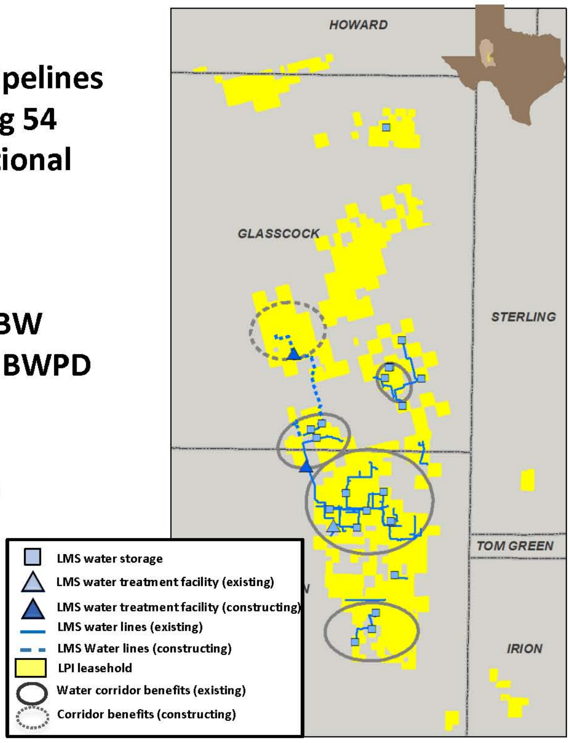


[1] As of 7/27/2017

Note: Infrastructure includes crude gathering/transportation, water gathering, distribution & recycle, natural gas gathering and centralized gas lift compression
Benefits defined as capital savings, LOE savings, price uplift and LMS net operating income

Significant Benefits through Water Infrastructure Investments

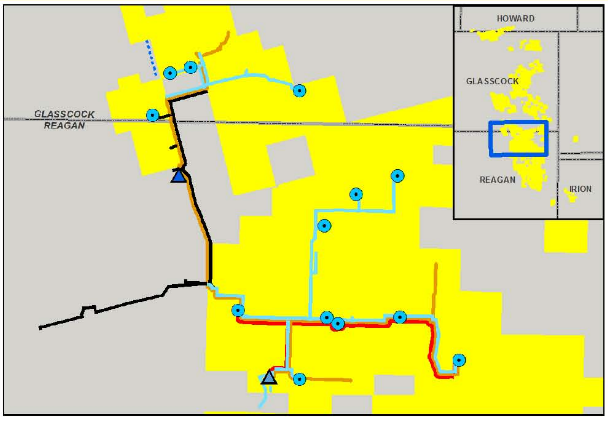
- Water infrastructure[1] consists of:
  - ~80 miles of total water gathering pipelines
  - Recycling plant capable of processing 54 MBWPD upon completion of 2 additional plants
  - Linked water storage assets with >12 MMBW capacity
  - Total storage capacity of ~15.7 MMBW
  - Access to ~340 wells with ~510,000 BWPD refresh rate
- Yields significant capital and LOE savings
- Enables drilling of multi-well pads
- Minimizes trucking



[1] As of 7/27/2017

Water Infrastructure Capital and LOE Savings

- 4.0 MMBW (73%) of total 2Q-17 produced water was gathered on pipe
  - Expected to increase to ~75% for FY 2017
- 1.9 MMBW (35%) of total 2Q-17 produced water was recycled by LMS
  - Expected to exit 2017 at ~60%
- 1.1 MMBW (12%) of water for completions in 2Q-17 was supplied with recycled water
  - Expected to average ~20% in 2017



Reagan North Production Corridor Area

LPI leasehold
Receipt point
LMS Water Treatment Facility (existing)
LMS Water Treatment Facility (constructing)
LMS produced water pipelines
LMS fresh water pipelines
LMS recycled water pipelines
3rd party pipelines
LMS Water lines (constructing)

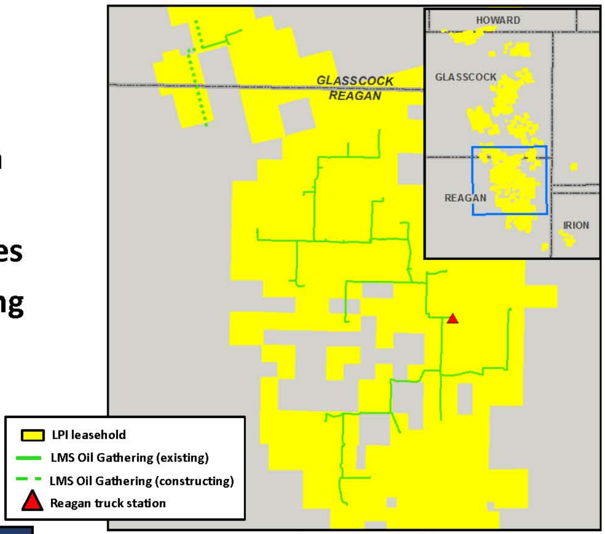
LMS Service	LPI Financial Benefits (2Q-17)		
	Category	($/BW)	($ MM)
Produced Water (Gathered vs Trucked)	Capital & LOE savings	$0.72	$2.9
Produced Water (Recycled vs Disposed)	Capital & LOE savings	$0.24	$0.5
Frac Water (Recycled vs Fresh)	Capital savings	$0.23	$0.3

LMS' water gathering system is expected to eliminate >100,000 truckloads of water in 2017

Note: 2017 estimates as of 7/27/2017

LMS Crude Gathering System Benefits

- ~45 miles of crude oil gathering lines
- 2.8 MMBO (82%) of gross operated production in 2Q-17 was gathered on pipe
- Reduces time from production to sales
- Benefits of system increase as trucking costs rise



Reagan North Production Corridor Area

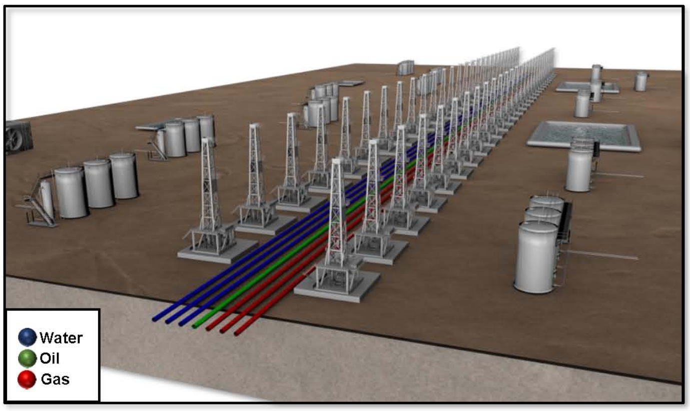
LMS Service	LPI Financial Benefits (2Q-17)		
	Category	($/Bbl)	($ MM)
Produced Oil (Gathered vs Trucked)	3rd-Party Income	$0.66	$1.9
Produced Oil (Gathered vs Trucked)	Increased Revenues	$0.45	$1.3

LMS expects to eliminate ~65,000 truckloads of oil in 2017

Note: As of 7/27/2017

Corridor Financial Benefits

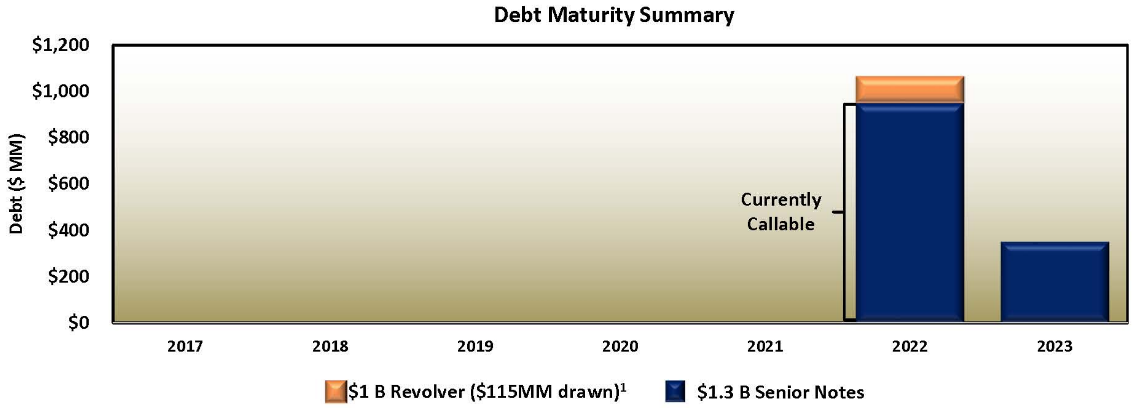
Production corridors benefited unit LOE by $0.60/BOE in 2Q-17 to $3.77/BOE



LMS Service	2016 Benefits Actual ($ MM)	2Q-17 Benefits Actual ($ MM)	2017 Benefits Estimated ($ MM)[1]	LPI Financial Benefits
Crude Gathering	$10.4	$3.1	$13.3	Increased revenues & 3rd-party income
Centralized Gas Lift	$0.9	$0.2	$1.0	LOE savings
Frac Water (Recycled vs Fresh)	$1.1	$0.3	$2.0	Capital savings
Produced Water (Recycled vs Disposed)	$2.0	$0.5	$2.1	Capital & LOE savings
Produced Water (Gathered vs Trucked)	$9.6	$2.9	$9.9	Capital & LOE savings
Corridor Benefit	$24.1	$7.0	$28.4	

[1] Benefits estimates as of 7/27/2017

Maintaining Strong Financial Position



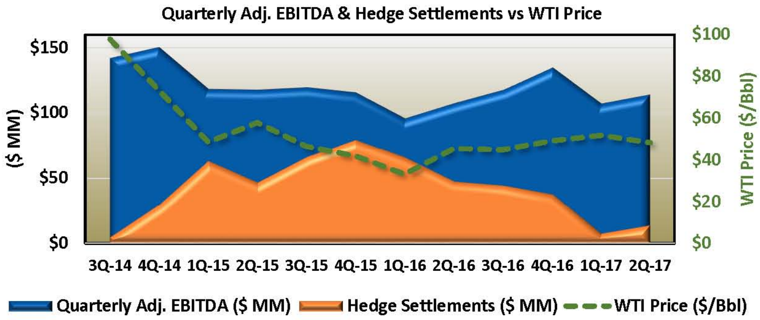
- **No debt due until 2022**
  - **$950 MM of notes due 2022 are currently callable at Laredo's option**
  - **$350 MM of notes due 2023 are callable in March 2018 at Laredo's option**

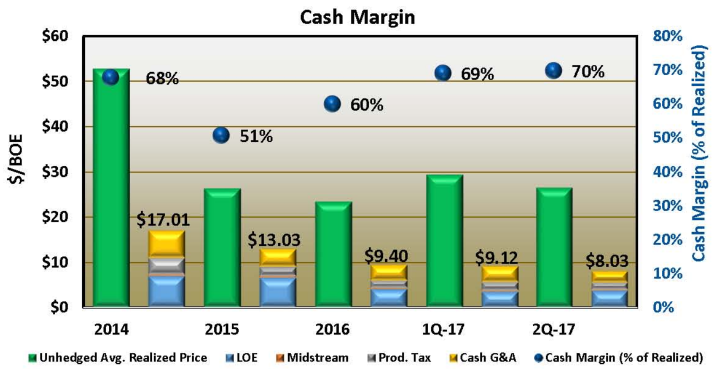
- **~$900 million of liquidity[1]**

[1] As of 8/7/2017, with $1 B Borrowing Base in place with amended and restated Senior Secured Credit Facility

Consistent Risk Management Philosophy Insures Long-Term Value

Hedge philosophy has worked as intended, providing cash flow stability as crude prices dropped at the end of 2014

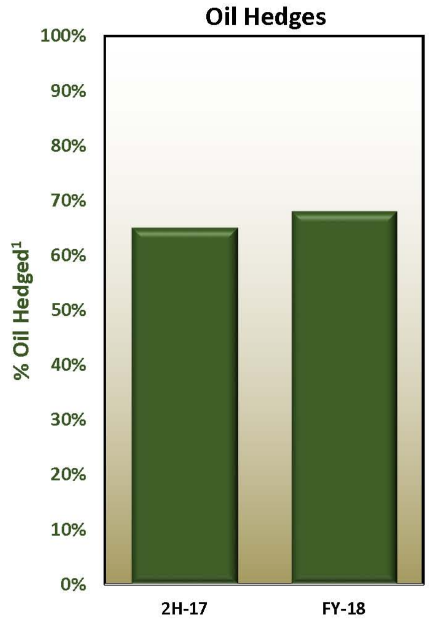


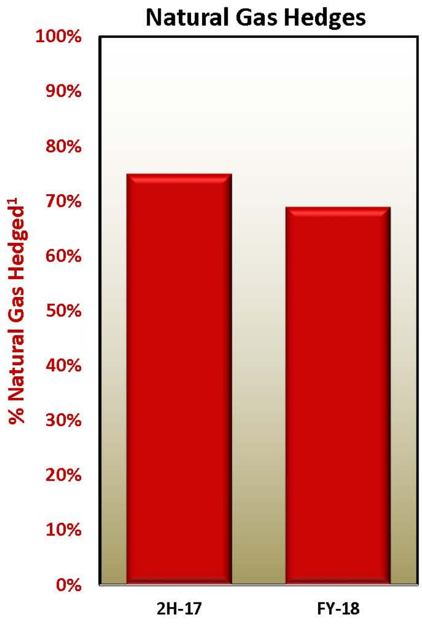


Risk management philosophy enabled company to adjust to current price environment and increase cash margin % to levels above 2014

Disciplined Hedging Program

Volumes Protected by Floors





Providing cash flow stability while retaining meaningful price upside opportunity

Weighted-Avg. Floor Price[2]	2H-17	FY-18
NYMEX	$55.82	$46.34

Weighted-Avg. Floor Price[2]	2H-17	FY-18
WAHA	$2.75	$2.50
HH[3]	$3.15	$2.90

[1] For percent hedged, utilizing actual 2016 production plus midpoint of 16% -19% growth for FY-17 and flat 2017 production for FY-18

[2] Oil derivatives are settled based on the month's average daily NYMEX price of WTI Light Sweet Crude Oil and natural gas derivatives are settled based on Inside FERC index price for West Texas WAHA for the calculation period

[3] Based on WAHA basis to Henry Hub (HH) of $0.40/Mcf as of 06/30/2017

Note: Does not include 2H-17 NGL hedges of 222,000 Bbl of ethane or 187,500 Bbl of propane

Oil, Natural Gas & Natural Gas Liquids Hedges

OIL[1]	2H-17	2018
Puts:		
Hedged volume (Bbls)	529,000	2,616,875
Weighted average price ($/Bbl)	$60.00	$54.01
Swaps:		
Hedged volume (Bbls)	1,012,000	-
Weighted average price ($/Bbl)	$51.54	-
Collars:		
Hedged volume (Bbls)	1,913,000	4,088,000
Weighted average floor price ($/Bbl)	$56.92	$41.43
Weighted average ceiling price ($/Bbl)	$60.23	$60.00
Total volume with a floor (Bbls)	3,454,600	6,704,875
Weighted-average floor price ($/Bbl)	$55.82	$46.34

NATURAL GAS[2]		
Put		
Hedged volume (MMBtu)	4,020,000	8,220,000
Weighted average floor price ($/MMBtu)	$2.50	$2.50
Collars:		
Hedged volume (MMBtu)	9,586,400	15,585,500
Weighted average floor price ($/MMBtu)	$2.86	$2.50
Weighted average ceiling price ($/MMBtu)	$3.54	$3.35
Total volume with a floor (MMBtu)	13,606,400	23,805,500
Weighted-average floor price ($/MMBtu)	$2.75	$2.50

NATURAL GAS LIQUIDS[3]		
Swaps - Ethane:		
Hedged volume (Bbls)	222,000	-
Weighted average price ($/Bbl)	$11.24	-
Swaps - Propane:		
Hedged volume (Bbls)	187,500	-
Weighted average price ($/Bbl)	$22.26	-
Total volume with a floor (Bbls)	409,500	-

Note: Open positions as of 6/30/2017
[1] Oil derivatives are settled based on the month's average daily NYMEX price of WTI Light Sweet Crude Oil
[2] Natural gas derivatives are settled based on Inside FERC index price for West Texas Waha for the calculation period
[3] Natural gas liquids derivatives are settled based on the month's daily average of OPIS Mt. Belvieu Purity Ethane and TET Propane

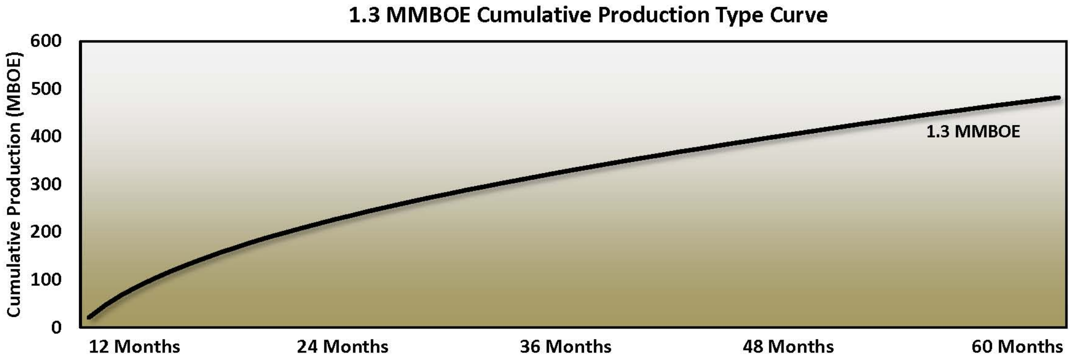
3Q-17 and 4Q-17 Guidance

	3Q-17	4Q-17
Production (MBOE/d)……	59 - 62	61 - 64
Product % of total production:		
Crude oil……	45% - 47%	45% - 47%
Natural gas liquids……	26% - 27%	*
Natural gas……	27% - 28%	*
Price Realizations (pre-hedge):		
Crude oil (% of WTI)……	~88%	*
Natural gas liquids (% of WTI)……	~31%	*
Natural gas (% of Henry Hub)……	~69%	*
Operating Costs & Expenses:		
Lease operating expenses ($/BOE)……	$3.60 - $4.00	*
Midstream expenses ($/BOE)……	$0.20 - $0.30	*
Production and ad valorem taxes (% of oil, NGL and natural gas revenue)……	6.25%	*
General and administrative expenses:		
Cash ($/BOE)……	$2.50 - $3.00	*
Non-cash stock-based compensation ($/BOE)……	$1.50 - $1.75	*
Depletion, depreciation and amortization ($/BOE)……	$7.00 - $7.50	*

*Will be provided in conjunction with third-quarter 2017 earnings release


LAREDO
PETROLEUM
Appendix

UWC & MWC 1.3 MMBOE Cumulative Production Type Curve

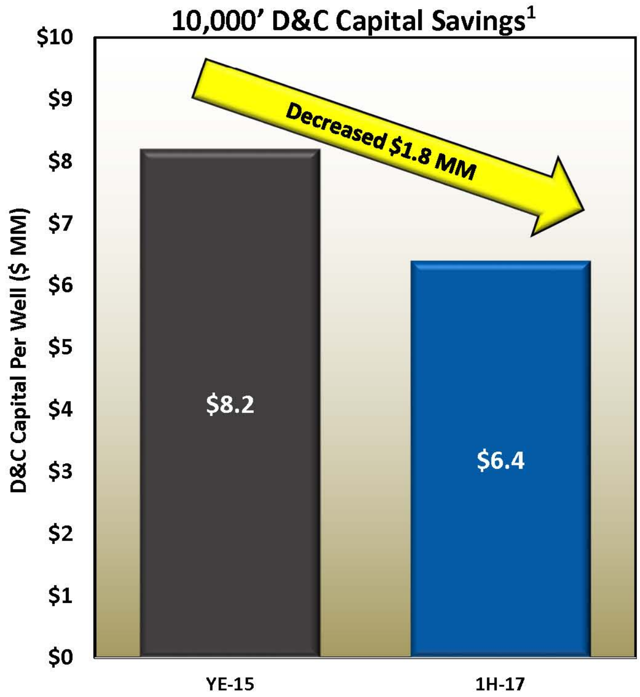


Months	Cumulative Production (MBOE)	Cumulative % Oil
12	189	60%
24	288	56%
36	363	54%
48	426	52%
60	482	51%

Previously increased UWC & MWC type curve due to well performance uplifts

Note: 10,000' lateral length with 1,800 lb/ft completions

Drilling & Completions Efficiencies Drive Savings



- Cost-efficient development:
  - Longer laterals
  - Multi-well packages
  - Zipper fracing
  - High-spec rigs

Focused on capital efficient drilling & completion operations

[1] Representative of multi-well pad costs through 1H-17. Represents 10,000' UWC/MWC wells utilizing 1,800 lb/ft sand and 54' perf cluster spacing.

Note: D&C capital includes: $1 MM for 1,800 lb/ft sand, pad preparation, well-site metering, heater treaters, separation equipment & artificial lift equipment FY-17 capital budget is unchanged, although upward pressure in service costs, if sustained throughout the remainder of the year, could result in a 5% - 10% increase in the FY-17 capital budget

2016 & 2017 YTD Actuals

		1Q-16	2Q-16	3Q-16	4Q-16	FY-16	1Q-17	2Q-17
Production	Production (3-Stream)							
	MBOE	4,204	4,338	4,718	4,889	18,149	4,716	5,336
	BOE/D	46,202	47,667	51,276	53,141	49,586	52,405	58,632
	% oil	48%	46%	46%	46%	47%	45%	47%
Realized Pricing	3-Stream Prices							
	Gas ($/Mcf)	$1.31	$1.31	$2.07	$2.13	$1.73	$2.31	$2.09
	NGL ($/Bbl)	$8.50	$12.24	$11.54	$14.79	$11.91	$16.49	$13.82
	Oil ($/Bbl)	$27.51	$39.37	$39.10	$43.98	$37.73	$46.91	$42.00
	Avg. Price ($/BOE)	$17.40	$23.64	$24.34	$27.82	$23.50	$29.42	$26.58
Unit Cost Metrics	3-Stream Unit Cost Metrics ($/BOE)							
	Lease Operating Expenses	$4.88	$4.43	$3.85	$3.56	$4.15	$3.60	$3.77
	Midstream	$0.14	$0.27	$0.22	$0.26	$0.22	$0.19	$0.17
	General & Administrative							
	Cash	$3.72	$3.33	$3.49	$3.28	$3.45	$3.47	$2.50
	Non-cash stock-based compensation	$0.91	$1.40	$2.05	$1.98	$1.61	$1.96	$1.63
	DD&A	$9.87	$7.88	$7.45	$7.68	$8.17	$7.23	$7.12

2015 Actuals

			1Q-15	2Q-15	3Q-15	4Q-15	FY-15
Production	Production (3-Stream)						
	MBOE		4,274	4,234	4,124	3,714	16,346
	BOE/D		47,487	46,532	44,820	40,368	44,782
		% oil	51%	46%	45%	45%	47%
Realized Pricing	3-Stream Prices						
	Gas ($/Mcf)		$2.14	$1.82	$2.01	$1.76	$1.93
	NGL ($/Bbl)		$13.34	$12.85	$10.36	$11.06	$11.86
	Oil ($/Bbl)		$41.73	$50.77	$42.88	$36.97	$43.27
	Avg. Price ($/BOE)		$27.64	$29.65	$25.37	$22.47	$26.41
Unit Cost Metrics	3-Stream Unit Cost Metrics ($/BOE)						
	Lease Operating Expenses		$7.58	$6.90	$6.09	$5.83	$6.63
	Midstream		$0.37	$0.38	$0.26	$0.43	$0.36
	General & Administrative						
	Cash		$3.99	$3.99	$3.89	$4.29	$4.03
	Non-cash stock-based compensation		$1.12	$1.49	$1.67	$1.75	$1.50
	DD&A		$16.83	$17.03	$16.19	$18.01	$16.99

2014 Two-Stream to Three-Stream Conversions

		1Q-14	2Q-14	3Q-14	4Q-14	FY-14
Production	**Production (2-Stream)**					
	MBOE	2,434	2,607	3,033	3,655	11,729
	BOE/D	27,041	28,653	32,970	39,722	32,134
	% oil	58%	58%	59%	60%	59%
	Production (3-Stream)					
	MBOE	2,912	3,078	3,569	4,267	13,827
	BOE/D	32,358	33,829	38,798	46,379	37,882
	% oil	49%	49%	50%	51%	50%
Realized Pricing	**2-Stream Prices**					
	Gas ($/Mcf)	$7.04	$6.08	$5.80	$4.46	$5.72
	Oil ($/Bbl)	$91.78	$94.47	$87.65	$65.05	$82.83
	Avg. Price ($/BOE)	$71.17	$70.13	$65.78	$49.70	$64.62
	3-Stream Prices					
	Gas ($/Mcf)	$4.00	$3.73	$3.25	$3.00	$3.45
	NGL ($/Bbl)	$32.88	$28.79	$29.21	$19.65	$27.00
	Oil ($/Bbl)	$91.78	$94.47	$87.65	$65.05	$82.83
	Avg. Price ($/BOE)	$59.70	$58.80	$55.41	$41.94	$52.81
Unit Cost Metrics	**2-Stream Unit Cost Metrics ($/BOE)**					
	Lease Operating Expenses	$8.95	$7.74	$8.30	$8.04	$8.23
	Midstream	$0.35	$0.59	$0.40	$0.50	$0.46
	General & Administrative					
	Cash	$9.58	$8.88	$6.89	$4.25	$7.07
	Non-cash stock-based compensation	$1.78	$2.46	$2.04	$1.70	$1.97
	DD&A	$20.38	$20.35	$21.08	$21.85	$21.01
	3-Stream Unit Cost Metrics ($/BOE)					
	Lease Operating Expenses	$7.48	$6.55	$7.05	$6.88	$6.98
	Midstream	$0.29	$0.50	$0.34	$0.43	$0.39
	General & Administrative					
	Cash	$8.01	$7.52	$5.85	$3.66	$6.00
	Non-cash stock-based compensation	$1.49	$2.08	$1.74	$1.44	$1.67
	DD&A	$17.03	$17.23	$17.91	$18.72	$17.83

Note: 2014 conversion based on management estimates. Utilizes an 18% volume uplift, for converting from 2-stream to 3-stream volumes

EBITDA Reconciliation

LPI Adjusted EBITDA *(in thousands)*		**2Q-17**
Net income	$	61,110
Plus:		
Depletion, depreciation and amortization	$	38,003
Impairment expense	$	-
Non-cash stock-based compensation, net of amounts capitalized	$	8,687
Accretion expense	$	943
Mark-to-market on derivatives:		
Gain on derivatives, net	$	(28,897)
Cash settlements received for matured derivatives, net	$	13,705
Cash settlements received for early termination of derivatives, net	$	4,234
Cash premiums paid for derivatives	$	(9,987)
Interest expense	$	23,173
Gain on disposal of assets, net	$	(805)
Income from equity method investee	$	(2,471)
Proportionate Adjusted EBITDA of equity method investee[1]	$	6,601
Adjusted EBITDA	$	114,296

[1]**Medallion Adjusted EBITDA** (Proportionate Adjusted EBITDA of equity method investee) *(in thousands)*		**2Q-17**
Income from equity method investee	$	2,471
Adjusted for proportionate share of:		
Depreciation and amortization	$	4,130
Proportionate Adjusted EBITDA of equity method investee	$	6,601