UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

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

SECURITIES EXCHANGE ACT OF 1934

Date of report (Date of earliest event reported): May 3, 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))

Item 2.02. Results of Operations and Financial Condition.

On May 3, 2017, Laredo Petroleum, Inc. (the "Company") announced its financial and operating results for the quarter ended March 31, 2017. Copies of the Company's press release and Presentation (as defined below) are furnished as Exhibit 99.1 and Exhibit 99.2, respectively, to this Current Report on Form 8-K and are incorporated herein by reference. The Company plans to host a teleconference and webcast on May 4, 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 8986853. A replay of the call will be available through Thursday, May 11, 2017, by dialing 1-855-859-2056, and using conference code 8986853. 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 May 3, 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 May 3, 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 May 3, 2017 announcing financial and operating results.
99.2	Presentation dated May 3, 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: May 3, 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 May 3, 2017 announcing financial and operating results.
99.2	Presentation dated May 3, 2017.

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 2017 First-Quarter Financial and Operating Results

TULSA, OK - May 3, 2017 - Laredo Petroleum, Inc. (NYSE: LPI) ("Laredo" or "the Company") today announced its 2017 first-quarter results, reporting net income attributable to common stockholders of $68.3 million, or $0.28 per diluted share. Adjusted Net Income, a non-GAAP financial measure, for the first quarter of 2017 was $23.8 million, or $0.10 per adjusted diluted share. Adjusted EBITDA, a non-GAAP financial measure, for the first quarter of 2017 was $107.4 million. Please see supplemental financial information at the end of this news release for reconciliations of non-GAAP financial measures.

2017 First-Quarter Highlights

- Produced 52,405 barrels of oil equivalent ("BOE") per day, an increase of approximately 13% from the first quarter of 2016
- Completed 13 horizontal development wells with an average completed lateral length of approximately 9,900 feet and conducted drilling operations on five wells with anticipated lateral lengths between 14,000 and 15,600 feet
- Recorded unit lease operating expenses ("LOE") of $3.60 per BOE, down approximately 26% from the first-quarter 2016 rate of $4.88 per BOE
- Recognized approximately $5.8 million in cash benefits from Laredo Midstream Services, LLC ("LMS") field infrastructure investments through reduced costs and increased revenue
- Grew transported volumes on the Medallion-Midland Basin pipeline system (defined below) to 148,834 barrels of oil per day ("BOPD") on average for the quarter, an increase of approximately 79% from the first quarter of 2016

"During the first quarter, Laredo again demonstrated how our early adoption of big data analytics, infrastructure build-out and operational best practices is creating value for our shareholders," commented Randy A. Foutch, Chairman and Chief Executive Officer. "We continue to push the envelope to create more robust workflows with our in-house technology to accelerate learning. Laredo is now progressing our analytical tools beyond the Earth Model to create geocellular reservoir models and combining them with advanced fracture modeling to direct our strategy towards high-density development. Our production corridor strategy is crucial for this type of development. Our infrastructure investments have driven our operating costs to among the lowest in the Midland Basin and are scalable to handle the movement of large volumes of oil, natural gas and water generated by high-density development."

Operational Update

In the first quarter of 2017, Laredo produced 52,405 BOE per day, completing 13 horizontal development wells with an average completed lateral length of approximately 9,900 feet. Flowback on a majority of the completions occurred in a compressed period, as the nine wells comprising the JL McMaster-Bodine package began production at approximately the same time. Production from these wells was concentrated in the last month of the first quarter and is expected to have a positive impact on second-quarter production.

The Company has developed a customized managed flowback procedure that is currently being utilized on all newly completed wells. Implementing this procedure has yielded compelling near-term production results, with wells utilizing managed flowback exhibiting higher total production and oil cuts versus wells not utilizing the procedure. Although wells utilizing Laredo's managed flowback procedure exhibited lower total production in the near term, the deficit was overcome in less than 90 days. Laredo currently estimates that the Company's wells utilizing the customized managed flowback procedure, which has no incremental capital cost, will recognize an increase in net present value of $300,000 to $400,000 per well in the first year of production.

The nine-well JL McMaster-Bodine package, completed in the first quarter of 2017, is indicative of the positive results of the Company's managed flowback procedure. While still early in its production history, the package is currently outperforming the Company's Upper/Middle Wolfcamp three-stream type curve by 26% and outperforming our oil type curve by 38%.

Results of the Company's testing of higher proppant concentrations, as part of its optimized completions, continue to improve. Laredo now has production data from 13 wells completed utilizing 2,400 pounds of proppant per lateral foot. This group of wells is currently outperforming the Company's Upper/Middle Wolfcamp type curve by approximately 40%. Included in this dataset are four wells completed in the first quarter of 2017 that utilized the higher proppant concentration. Additionally, the Company completed a well utilizing 3,300 pounds of proppant per lateral foot. Although it is too early to make a determination of the economic value of proppant concentrations greater than 1,800 pounds per lateral foot, Laredo will continue to monitor production data and expects to conduct additional tests in the second quarter of 2017.

Laredo continues to capitalize on its contiguous acreage base to focus on drilling capital-efficient, long-lateral wells. During the first quarter, the Company successfully completed the drilling of two wells with drilled lateral lengths greater than 14,000 feet and began drilling three wells expected to have drilled lateral lengths greater than 15,000 feet. Laredo expects to continue drilling longer laterals as the Company has definitive data showing no degradation in well performance as lateral lengths exceed 10,000 feet, enabling efficiencies that lower cost per foot and drive higher rates of return.

Laredo continues to utilize its extensive dataset and in-house technology development to enhance shareholder value. The Company used big data concepts to create its proprietary multivariate Earth Model to help isolate production drivers and measure their impact. This has led to significant outperformance of the Company's type curves by wells utilizing this analysis. Laredo is now using this data to create high-resolution geocellular reservoir models and fracture models to guide strategic testing of high-density development. In the second quarter of 2017, the Company will begin a six-well package in the Upper, Middle and Lower Wolfcamp to test the co-development of multiple landing points within the Upper and Middle Wolfcamp formations. The results of this test are anticipated at year-end 2017 and are expected to refine spacing and completion concepts that further optimize Laredo's development plan and enhance the value of its acreage.

In the second quarter of 2017, the Company expects to complete approximately 18 wells with an average completed lateral length of approximately 10,100 feet. The completion count will be impacted by the timing of packages and the nature of completion tests. As the Company tests tighter spacing of perforation clusters and acquires microseismic data of these tests, the flowback timing of these wells can vary versus scheduled timing.

Lease operating expenses again benefited from the Company's investments in field infrastructure and the concentration of drilling around Laredo's production corridors. Total LOE in the first quarter of 2017 decreased approximately 2% from the fourth quarter of 2016. Infrastructure-related savings reduced unit LOE by $0.46 per BOE to $3.60 per BOE in the first quarter of 2017. The Company anticipates unit LOE will continue to benefit from prior infrastructure investments and believes the infrastructure-related savings will grow should costs increase.

In the first quarter of 2017, well costs were in-line with Laredo's expectations of $6.4 million for a 10,000-foot Upper or Middle Wolfcamp well completed with 1,800 pounds per lateral foot of proppant. During the second quarter of 2017, the Company expects to experience upward pressure on the stimulation services segment of well costs. Laredo continues to mitigate a portion of these increases through efficiency gains, procurement initiatives and evaluation of new vendors. Due to the variability of the current commodity price environment and the Company's historical success managing service cost increases, Laredo is not adjusting well cost or budget estimates at this time.

Laredo Midstream Services Update

During the first quarter of 2017, LMS gathered on pipe 73% of the Company's gross operated oil production and 65% of total produced water and generated approximately $5.8 million of total cash benefit for the Company. The Company anticipates the percentage of gross operated oil production and total produced water to be gathered by LMS to increase throughout 2017, contributing to an expected total cash benefit of approximately $28 million during 2017.

Transported volumes on the Medallion Gathering & Processing, LLC pipeline system ("Medallion-Midland Basin pipeline system"), in which LMS owns a 49% interest, grew to an average of 148,834 BOPD, an increase of approximately 79% from the first quarter of 2016 and up 15% from the fourth quarter of 2016. The system is expected to transport an average of approximately 175,000 BOPD during the second quarter of 2017.

2017 Capital Program

During the first quarter of 2017, Laredo invested approximately $109 million in exploration and development activities. Other expenditures incurred during the quarter included approximately $13 million in bolt-on land acquisitions and lease extensions, approximately $1 million in infrastructure held by LMS and approximately $5 million in capitalized employee-related costs.

Liquidity

At March 31, 2017, the Company had cash and cash equivalents of approximately $30 million and undrawn capacity under the senior secured credit facility of $750 million.

The Company recently amended and restated its senior secured credit facility, which now matures in 2022. The Company's borrowing base increased to $1.0 billion from $815 million. At May 2, 2017, the Company had cash and equivalents of approximately $20 million and undrawn capacity under the senior secured credit facility of $925 million, resulting in total liquidity of approximately $945 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 March 31, 2017, the Company had hedges in place for the remaining three quarters of 2017 for 5,163,125 barrels of oil at a weighted-average floor price of $55.82 per barrel. A substantial portion of Laredo's remaining 2017 oil hedges retain the benefit of an increase in the price of oil with hedges covering 2,860,000 barrels structured as collars with a weighted-average ceiling price of $86.00 per barrel and hedges covering 790,625 barrels in the form of puts and thus do not have a ceiling.

The Company also had hedges in place for the remaining three quarters of 2017 for 20,357,500 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 333,000 barrels of ethane at $11.24 per barrel and 281,250 barrels of propane at $22.26 per barrel.

At March 31, 2017, for 2018, the Company had hedged 3,458,375 barrels of oil at a weighted-average floor price of $53.71 per barrel and 12,855,500 MMBtu of natural gas at a weighted-average floor price of $2.50 per MMBtu, priced at the WAHA hub. Subsequently, the Company hedged an additional 10,950,000 MMBtu of natural gas for 2018 at a weighted-average floor price of $2.50 per MMBtu, priced at the WAHA hub.

Second-Quarter and Full-Year 2017 Guidance

The Company is reiterating its previously stated anticipated full-year 2017 production growth guidance of at least 15%. The table below reflects the Company’s guidance for the second quarter of 2017:

	2Q-2017
Production (MBOE/d)	55 - 58
Product % of total production:	
Crude oil	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)	~29%
Natural gas (% of Henry Hub)	~68%
Operating Costs & Expenses:	
Lease operating expenses ($/BOE)	$3.50 - $4.00
Midstream expenses ($/BOE)	$0.20 - $0.30
Production and ad valorem taxes (% of oil, NGL and natural gas revenue)	6.5%
General and administrative expenses:	
Cash ($/BOE)	$3.00 - $3.50
Non-cash stock-based compensation ($/BOE)	$1.75 - $2.00
Depletion, depreciation and amortization ($/BOE)	$7.25 - $7.75

Conference Call Details

On Thursday, May 4, 2017, at 7:30 a.m. CT, Laredo will host a conference call to discuss its first-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 8986853, approximately 10 minutes prior to the scheduled conference time. International participants should dial 253.336.8309, also using conference code 8986853. A telephonic replay will be available approximately two hours after the call on May 4, 2017 through Thursday, May 11, 2017. Participants may access this replay by dialing 855.859.2056, using conference code 8986853.

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 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 March 31, 2017	2016
	(unaudited)	
Revenues:		
Oil, NGL and natural gas sales	$ 138,736	$ 73,142
Midstream service revenues	2,999	1,801
Sales of purchased oil	47,271	31,614
Total revenues	189,006	106,557
Costs and expenses:		
Lease operating expenses	16,992	20,518
Production and ad valorem taxes	8,781	6,435
Midstream service expenses	916	609
Costs of purchased oil	50,256	32,946
General and administrative	25,597	19,451
Depletion, depreciation and amortization	34,112	41,478
Impairment expense	—	161,064
Other operating expenses	1,026	844
Total costs and expenses	137,680	283,345
Operating income (loss)	51,326	(176,788)
Non-operating income (expense):		
Gain on derivatives, net	36,671	17,885
Income from equity method investee	3,068	2,298
Interest expense	(22,720)	(23,705)
Other, net	(69)	(61)
Non-operating income (expense), net	16,950	(3,583)
Income (loss) before income taxes	68,276	(180,371)
Income tax:		
Deferred	—	—
Total income tax	—	—
Net income (loss)	$ 68,276	$ (180,371)
Net income (loss) per common share:		
Basic	$ 0.29	$ (0.85)
Diluted	$ 0.28	$ (0.85)
Weighted-average common shares outstanding:		
Basic	238,505	211,560
Diluted	244,379	211,560

Laredo Petroleum, Inc.
Condensed consolidated balance sheets

(in thousands)	March 31, 2017	December 31, 2016
Assets:	(unaudited)	(unaudited)
Current assets	$ 152,629	$ 154,777
Property and equipment, net	1,401,484	1,366,867
Other noncurrent assets	264,483	260,702
Total assets	$ 1,818,596	$ 1,782,346
Liabilities and stockholders' equity:		
Current liabilities	$ 162,335	$ 187,945
Long-term debt, net	1,349,591	1,353,909
Other noncurrent liabilities	53,760	59,919
Stockholders' equity	252,910	180,573
Total liabilities and stockholders' equity	$ 1,818,596	$ 1,782,346

Laredo Petroleum, Inc.
Condensed consolidated statements of cash flows

(in thousands)	Three months ended March 31, 2017	2016
	(unaudited)	
Cash flows from operating activities:		
Net income (loss)	$ 68,276	$ (180,371)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depletion, depreciation and amortization	34,112	41,478
Impairment expense	—	161,064
Non-cash stock-based compensation, net of amounts capitalized	9,224	3,838
Mark-to-market on derivatives:		
Gain on derivatives, net	(36,671)	(17,885)
Cash settlements received for matured derivatives, net	7,451	65,937
Cash settlements received for early terminations of derivatives, net	—	80,000
Cash premiums paid for derivatives	(2,107)	(81,850)
Other, net	(762)	(6,494)
Cash flows from operations before changes in working capital and other noncurrent liabilities	79,523	65,717
Decrease in working capital	(15,695)	(9,131)
Decrease in other noncurrent liabilities	(44)	(69)
Net cash provided by operating activities	63,784	56,517
Cash flows from investing activities:		
Capital expenditures:		
Oil and natural gas properties	(110,542)	(105,155)
Midstream service assets	(1,731)	(1,937)
Other fixed assets	(1,203)	(630)
Investment in equity method investee	—	(26,660)
Proceeds from dispositions of capital assets, net of selling costs	59,515	218
Net cash used in investing activities	(53,961)	(134,164)
Cash flows from financing activities:		
Borrowings on Senior Secured Credit Facility	50,000	85,000
Payments on Senior Secured Credit Facility	(55,000)	(25,000)
Other, net	(7,143)	(1,412)
Net cash (used in) provided by financing activities	(12,143)	58,588
Net decrease in cash and cash equivalents	(2,320)	(19,059)
Cash and cash equivalents, beginning of period	32,672	31,154
Cash and cash equivalents, end of period	$ 30,352	$ 12,095

Laredo Petroleum, Inc.
Selected operating data

	Three months ended March 31,	
	2017	2016
	(unaudited)	
Sales volumes:		
Oil (MBbl)	2,120	2,006
NGL (MBbl)	1,263	1,066
Natural gas (MMcf)	8,000	6,796
Oil equivalents (MBOE)[1][2]	4,716	4,204
Average daily sales volumes (BOE/D)[1]	52,405	46,202
% Oil	45%	48%
Average sales prices:		
Oil, realized ($/Bbl)[1][3]	$ 46.91	$ 27.51
NGL, realized ($/Bbl)[1][3]	$ 16.49	$ 8.50
Natural gas, realized ($/Mcf)[1][3]	$ 2.31	$ 1.31
Average price, realized ($/BOE)[1][3]	$ 29.42	$ 17.40
Oil, hedged ($/Bbl)[1][4]	$ 49.70	$ 56.84
NGL, hedged ($/Bbl)[1][4]	$ 16.04	$ 8.50
Natural gas, hedged ($/Mcf)[1][4]	$ 2.31	$ 2.08
Average price, hedged ($/BOE)[1][4]	$ 30.55	$ 32.64
Average costs per BOE sold[1]:		
Lease operating expenses	$ 3.60	$ 4.88
Production and ad valorem taxes	1.86	1.53
Midstream service expenses	0.19	0.14
General and administrative:		
Cash	3.47	3.72
Non-cash stock-based compensation, net of amounts capitalized	1.96	0.91
Depletion, depreciation and amortization	7.23	9.87
Total	$ 18.31	$ 21.05

(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 March 31,	
(in thousands)	2017	2016
	(unaudited)	
Property acquisition costs:		
Evaluated	$ —	$ —
Unevaluated	—	—
Exploration costs	15,543	7,263
Development costs[1]	111,158	81,886
Total costs incurred	$ 126,701	$ 89,149

(1) Development costs include $0.1 million in asset retirement obligations for each of the three months ended March 31, 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, 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 months ended March 31, 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 months ending March 31, 2017 and 2016, we present a line item that calculates Adjusted Net Income per Adjusted diluted common share. Accordingly, the prior period's Adjusted Net Income has been modified for comparability.

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

	Three months ended March 31,	
(in thousands, except for per share data, unaudited)	**2017**	**2016**
Net income (loss)	$ 68,276	$ (180,371)
Plus:		
Mark-to-market on derivatives:		
Gain on derivatives, net	(36,671)	(17,885)
Cash settlements received for matured derivatives, net	7,451	65,937
Cash settlements received for early terminations of derivatives, net	—	80,000
Cash premiums paid for derivatives	(2,107)	(81,850)
Impairment expense	—	161,064
Loss on disposal of assets, net	214	160
Adjusted net income before adjusted income tax expense	37,163	27,055
Adjusted income tax expense	(13,379)	(9,740)
Adjusted Net Income	$ 23,784	$ 17,315
Net income (loss) per common share:		
Basic	$ 0.29	$ (0.85)
Diluted	$ 0.28	$ (0.85)
Adjusted Net Income per common share:		
Basic	$ 0.10	$ 0.08
Adjusted diluted	$ 0.10	$ 0.08
Weighted-average common shares outstanding:		
Basic	238,505	211,560
Diluted	244,379	211,560
Adjusted diluted	244,379	213,995

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, 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 March 31,	
(in thousands, unaudited)	**2017**	**2016**
Net income (loss)	$ 68,276	$ (180,371)
Plus:		
Depletion, depreciation and amortization	34,112	41,478
Impairment expense	—	161,064
Non-cash stock-based compensation, net of amounts capitalized	9,224	3,838
Accretion expense	928	844
Mark-to-market on derivatives:		
Gain on derivatives, net	(36,671)	(17,885)
Cash settlements received for matured derivatives, net	7,451	65,937
Cash settlements received for early terminations of derivatives, net	—	80,000
Cash premiums paid for derivatives	(2,107)	(81,850)
Interest expense	22,720	23,705
Loss on disposal of assets, net	214	160
Income from equity method investee	(3,068)	(2,298)
Proportionate Adjusted EBITDA of equity method investee[1]	6,365	3,684
Adjusted EBITDA	$ 107,444	$ 98,306

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

	Three months ended March 31,	
(in thousands, unaudited)	**2017**	**2016**
Income from equity method investee	$ 3,068	$ 2,298
Adjusted for proportionate share of:		
Depreciation and amortization	3,297	1,386
Proportionate Adjusted EBITDA of equity method investee	$ 6,365	$ 3,684

# # #

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17-5

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.

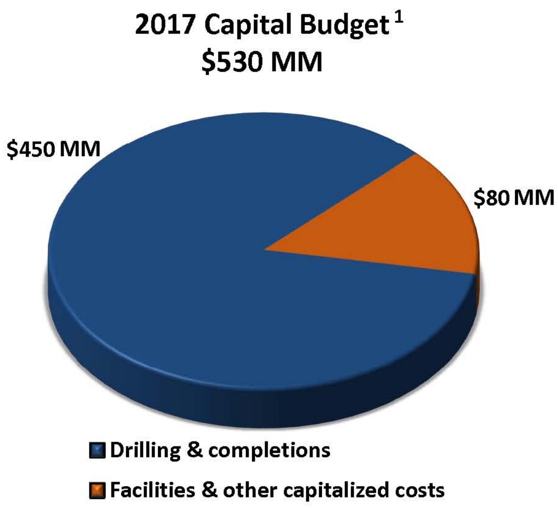
1Q-17 Highlights

- Grew production ~13% from 1Q-16
- Completed 13 Hz wells with an average lateral length of ~9,900’
- Conducted drilling operations on 5 Hz wells with anticipated lateral lengths between 14,000’ and 15,600’
- Reduced unit LOE to $3.60 per BOE, down 26% from 1Q-16
- Recognized $5.8 MM in cash benefits from LMS field infrastructure investments
- Grew transported volumes on Medallion-Midland Basin system by 79% from 1Q-16

2017 Capital and Operating Expectations

2017 Drilling & Completions

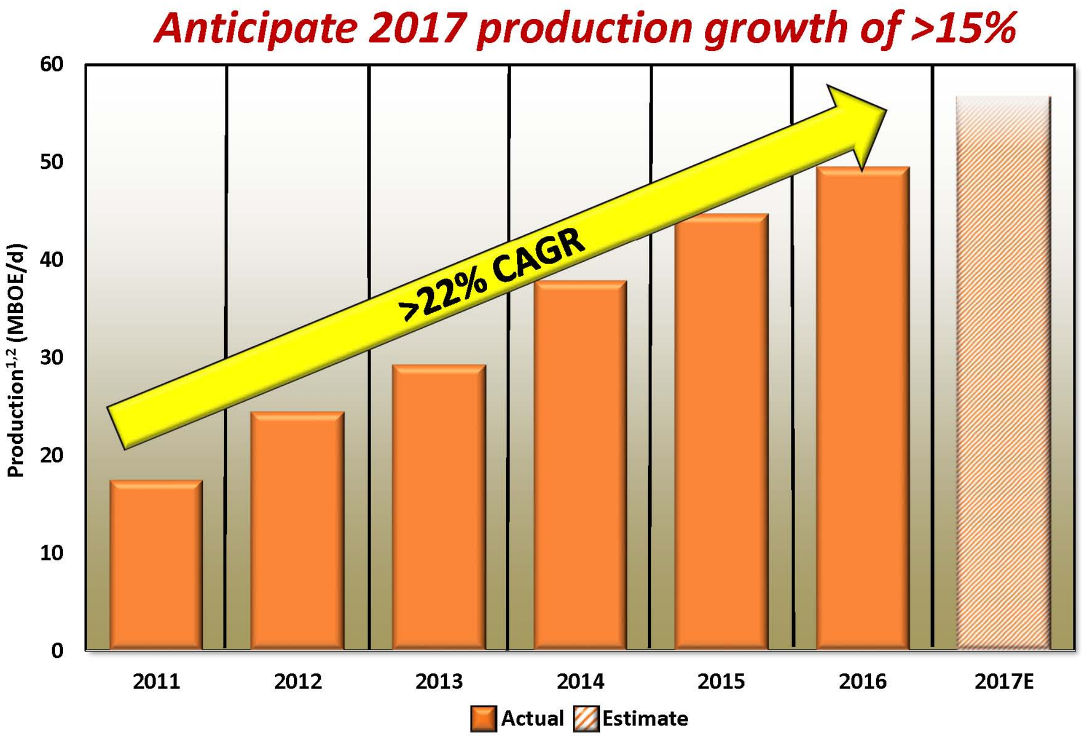
- Operating 4 Hz rigs
- Drilling and completing ~70 Hz wells
- ~85% targeting the UWC & MWC
- ~95% average working interest
- Developed as an average of 4 - 5 well packages



2017 lateral length expected to average ~10,000'

[1] Does not include acquisitions or investments in Medallion-Midland Basin system

Consistent Production Growth



[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

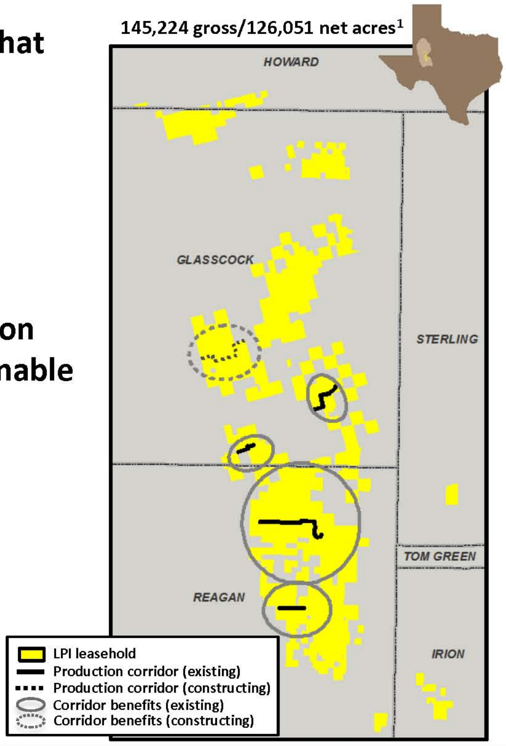
[2] 2011 - 2013 adjusted for Granite Wash divestiture, closed August 1, 2013

Capitalizing on Contiguous Acreage Position

- **The company has identified >2,000 locations that support lateral lengths of 10,000'+ on its contiguous acreage**
- **The expected average lateral length for wells drilled in 2017 is ~10,000'**
- **Centralized infrastructure in multiple production corridors and the ability to drill long laterals enable increased capital and operational efficiencies**

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

145,224 gross/126,051 net acres[1]



[1] As of 3/31/17

Multiple Targeted Horizons

2017 Drilling Targets: Upper Wolfcamp, Middle Wolfcamp, Lower Wolfcamp, Cline

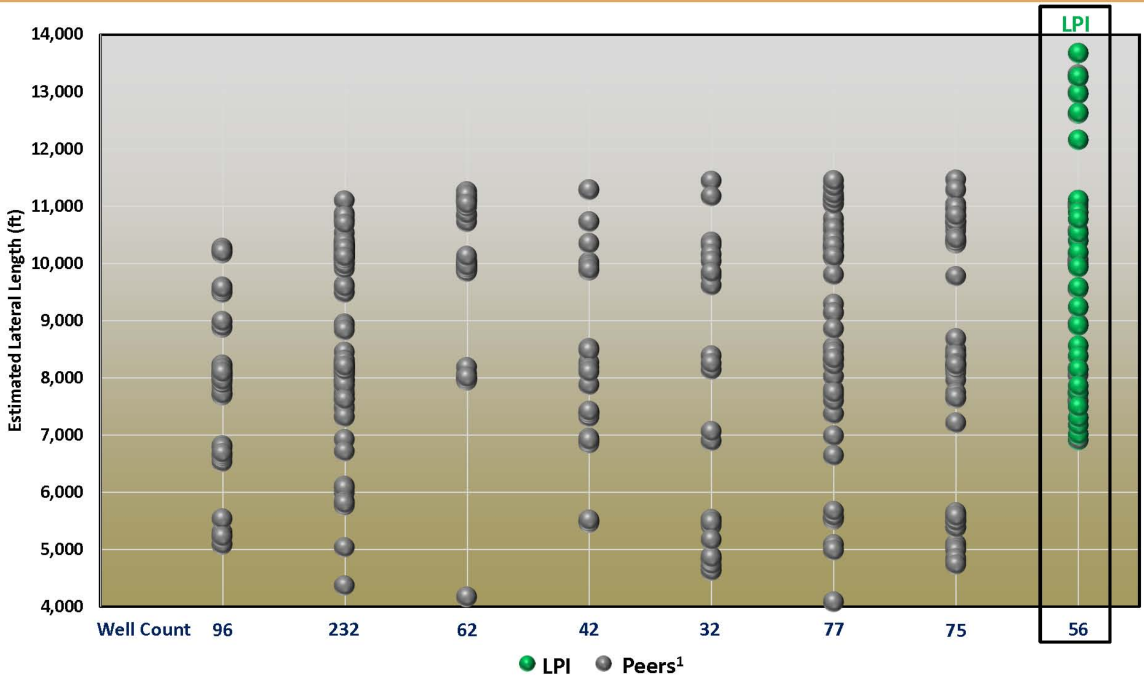
4,500 gross ft. of prospective zones

	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	128	~405'	72	2 - 3
Middle Wolfcamp	72	~620'	69	2 - 3
Lower Wolfcamp	30	~520'	69	1
Canyon	2	~470'	40	1
Penn Shale				
Cline	58	~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 3/31/17

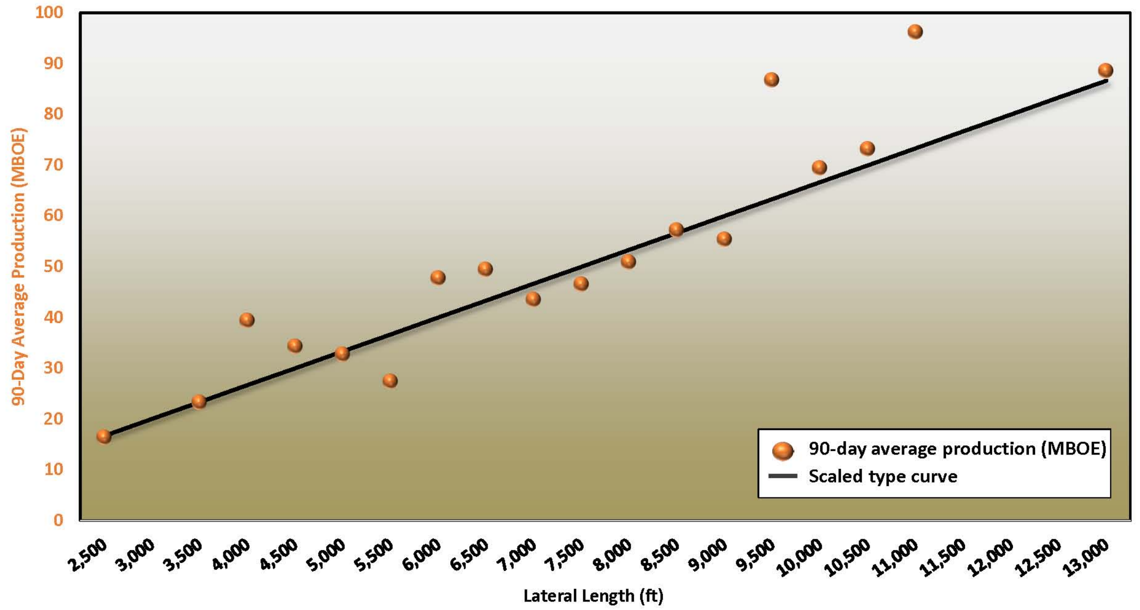
Peer-Leading Long-Lateral Execution



LPI has drilled 7 of the 12 longest laterals in the Midland Basin

[1] Peers: Callon, Diamondback, Encana, Energen, Parsley, Pioneer & RSP Permian
Note: Data is from IHS Enerdeq for the period of 04/01/2016 – 3/31/2017 for Glasscock, Howard, Irion, Midland, Reagan and Martin & Upton counties, TX wells with lateral length greater than 4,000'

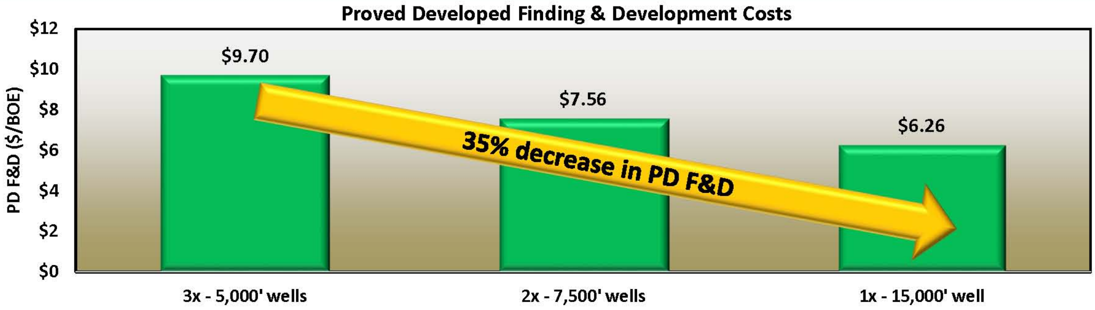
Laredo's Long Laterals Maintain Productivity

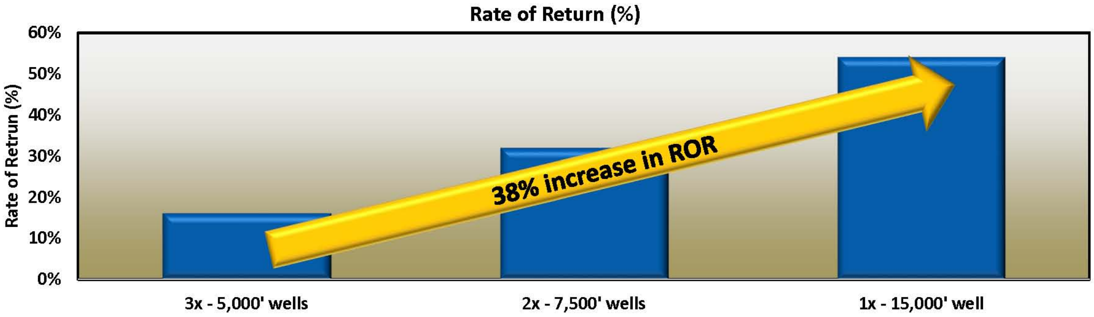


Laterals longer than 10,000' show NO productivity loss

Note: 1.3 MMBOE UWC/MWC 10,000' type curve utilized, scaled to each respective lateral length

Economic Benefits of Longer Laterals

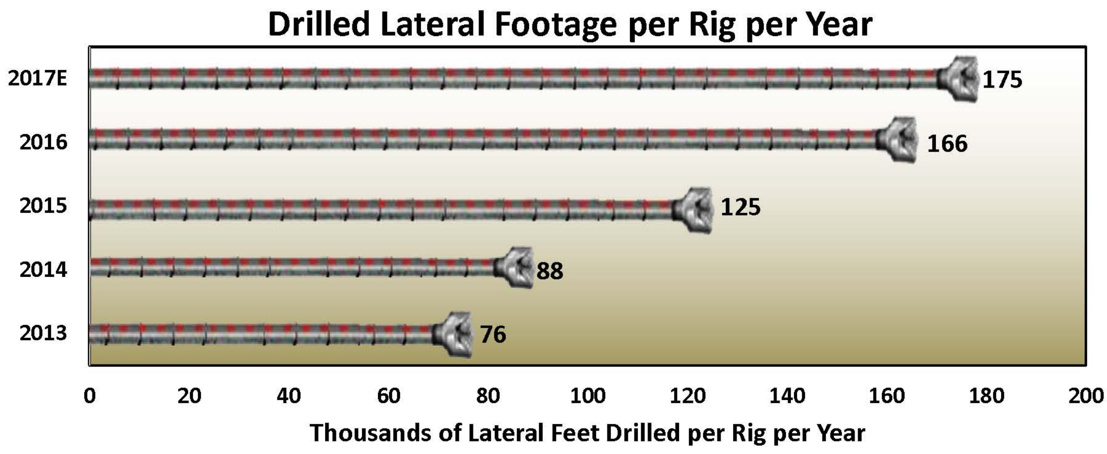




Longer laterals develop equivalent resources for reduced capital, yielding capital efficiency and rate of return improvements

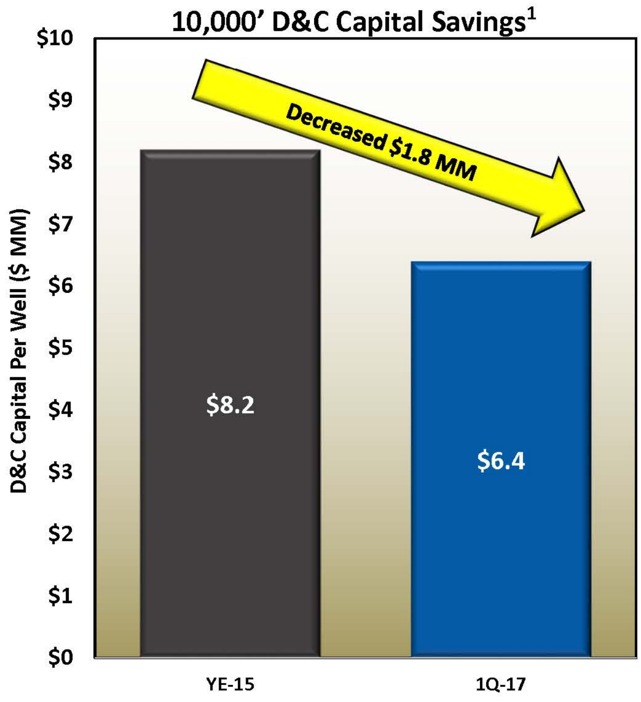
Note: Utilizing 75% NRI and EUR of 1.3 MMBOE per 10,000' lateral
Utilizing flat benchmark of WTI: $56.10/Bbl & HH: $3.00/Mcf and flat realized pricing of WTI: $50.49/Bbl, HH: $2.16/Mcf & NGLs: $17.95/Bbl

Drilling Efficiencies Maintain Lower Well Costs



Significant drilling efficiency improvements realized without material increases in capex per rig, improving capital efficiency

Drilling & Completions Efficiencies Drive Savings



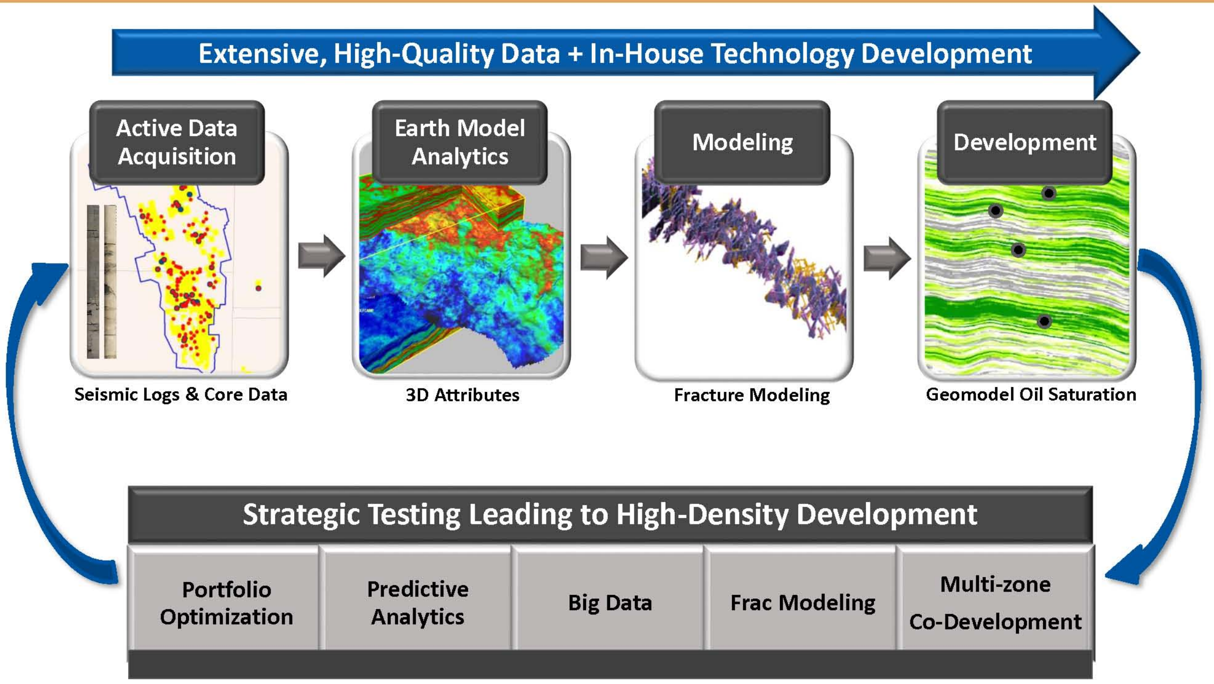
- **Cost-efficient development:**
  - **Longer laterals**
  - **Multi-well packages**
  - **Zipper fracing**
  - **High-spec rigs**

Focused on capital efficient drilling & completion operations

[1] Representative of multi-well pad costs

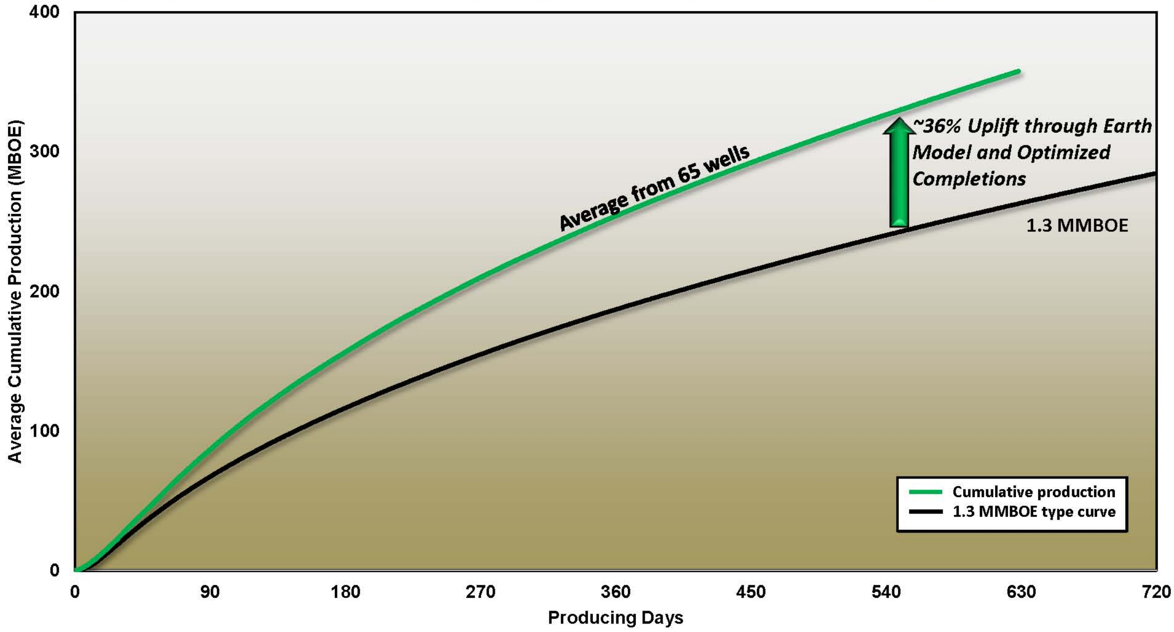
Note: D&C capital includes: $1 MM for 1,800 lb/ft sand, pad preparation, well-site metering, heater treaters, separation equipment & artificial lift equipment

Accelerating Learning to Enhance Shareholder Returns



Earth Model and Completions Optimization Benefits

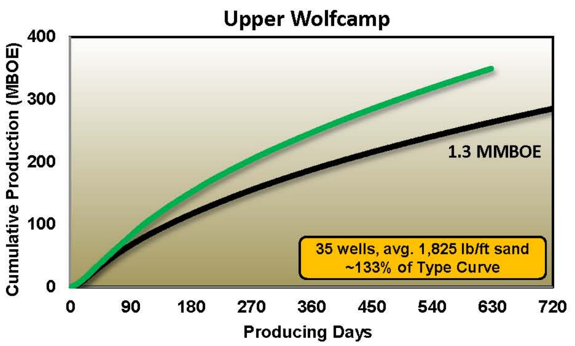
Wells utilizing the Earth Model and optimized completions have performed at an average of ~136% of 1.3 MMBOE Type Curve[1]

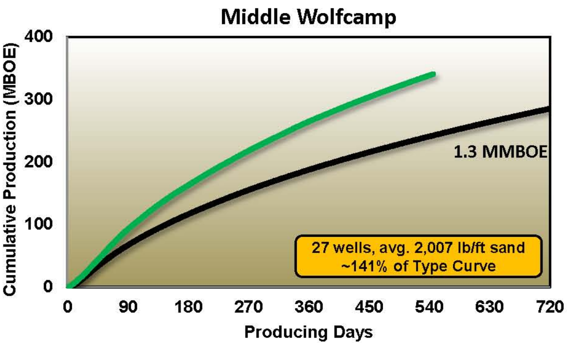


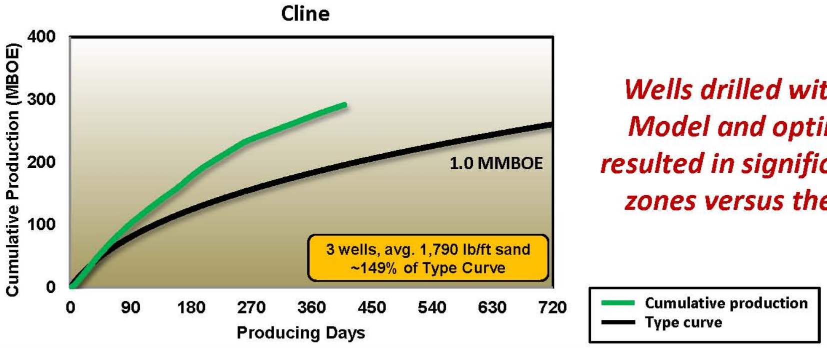
[1] Average cumulative production data through 4/26/17. This includes 65 Hz UWC/MWC wells have utilized both the Earth Model and optimized completions with avg. ~1,900 lb/ft sand

Note: Production has been scaled to 10,000' EUR type curves and non-producing days (for shut-ins) have been removed

Multivariate Earth Model Enhancing Production







Wells drilled with the multivariate Earth Model and optimized completions have resulted in significant outperformance in all zones versus the Company's type curves

Note: Average cumulative production data through 4/26/17. Production has been scaled to 10,000' EUR type curves and non-producing days (for shut-ins) have been removed

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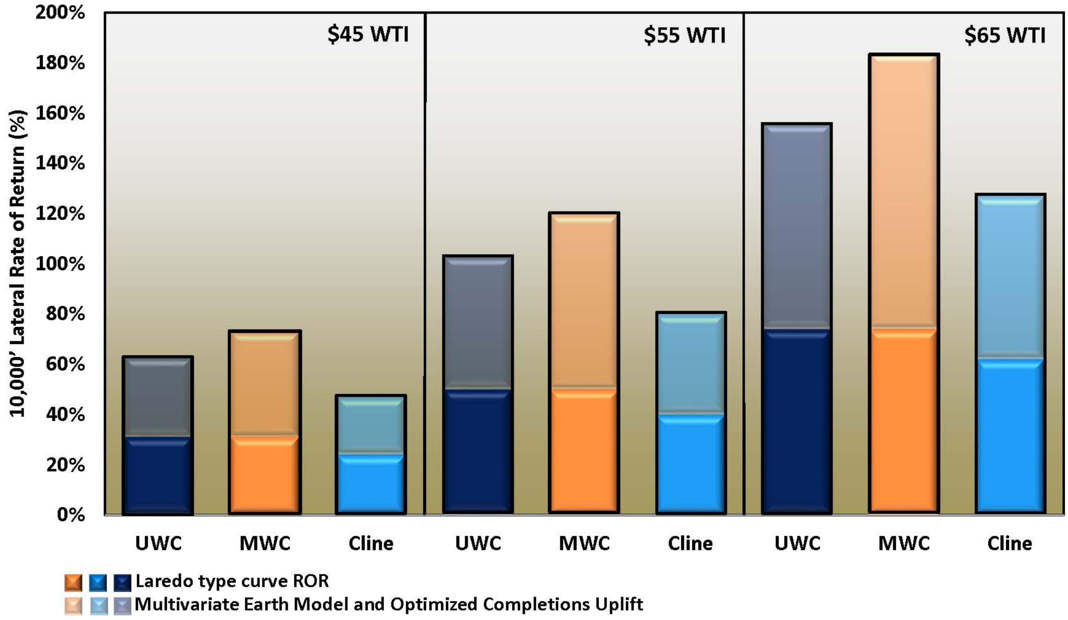
Multivariate Earth Model Driving Meaningful Uplift in Returns

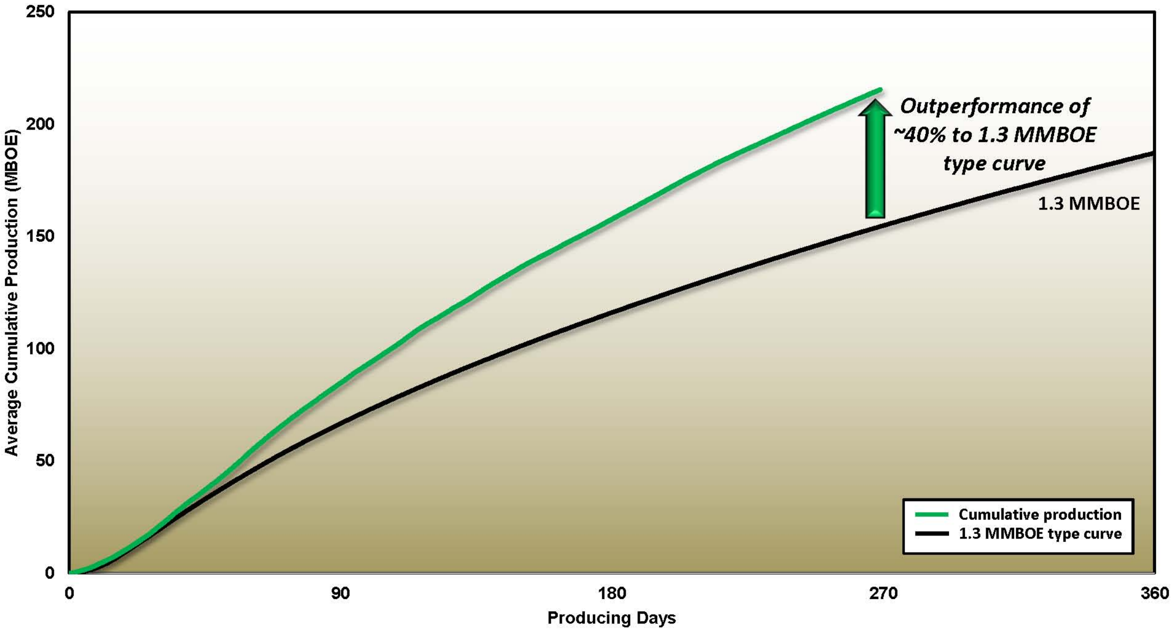


Demonstrated performance uplifts in each zone yield significant return improvements

Note: Rate of returns calculated using benchmark prices of WTI: $45.00/Bbl, $55.00/Bbl, $65.00/Bbl & HH: $3.00/Mcf, $3.25/Mcf, $3.50/Mcf and realized pricing of WTI: $40.95/Bbl, $50.05/Bbl, $59.15/Bbl & HH: $2.10/Mcf, $2.28/Mcf, $2.45/Mcf & NGLs: $14.40/Bbl, $17.60/Bbl, $20.80/Bbl
ROR includes static capital for 10,000' laterals and uplift reflective of current multivariate Earth Model and optimized completions outperformance above type curve by target and can change based on observed performance

Latest Optimization Tests Continue to Improve

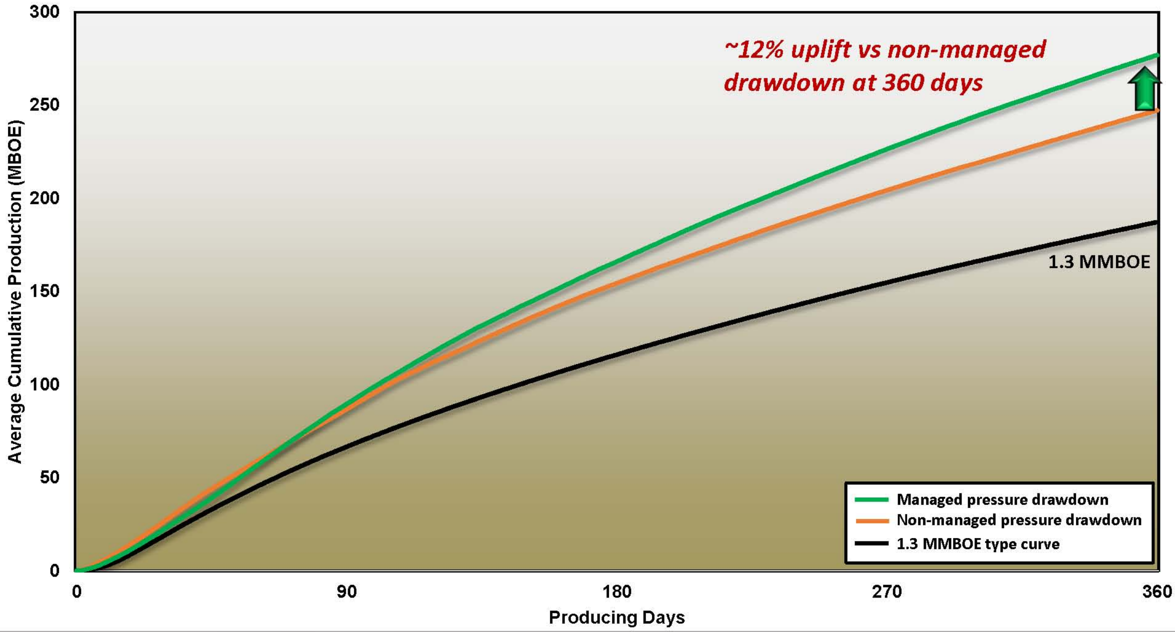
13 wells utilizing the multivariate Earth Model and optimized completions with 2,400 lb/ft sand are yielding results significantly greater than type curve



[1] Average cumulative production data through 4/26/17. This includes 13 Hz UWC/MWC wells have utilized both the Earth Model and 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

Managed Pressure Drawdown Enhances Value

Managed pressure drawdown increases net present value
$300,000 - $400,000 in the first year of production

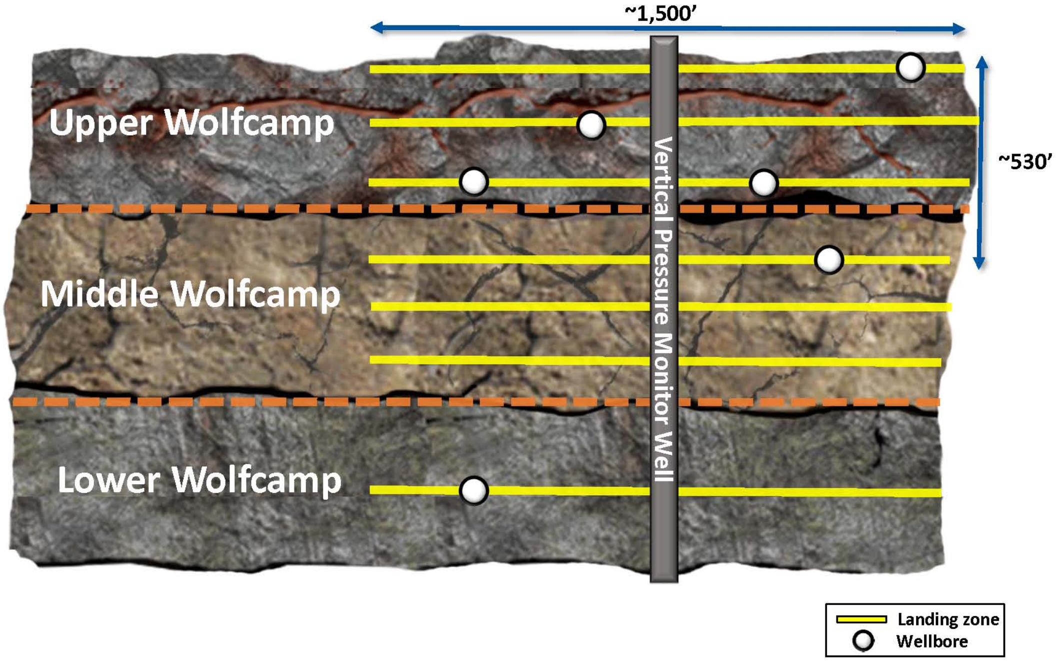


[1] Average cumulative production data through 4/26/17. 20 wells utilized the managed pressure drawdown, 19 wells utilized the non-managed pressure drawdown. All wells utilized 1,800 lb/ft of proppant and optimized completions

Note: Production has been scaled to 10,000' EUR type curves and non-producing days (for shut-ins) have been removed

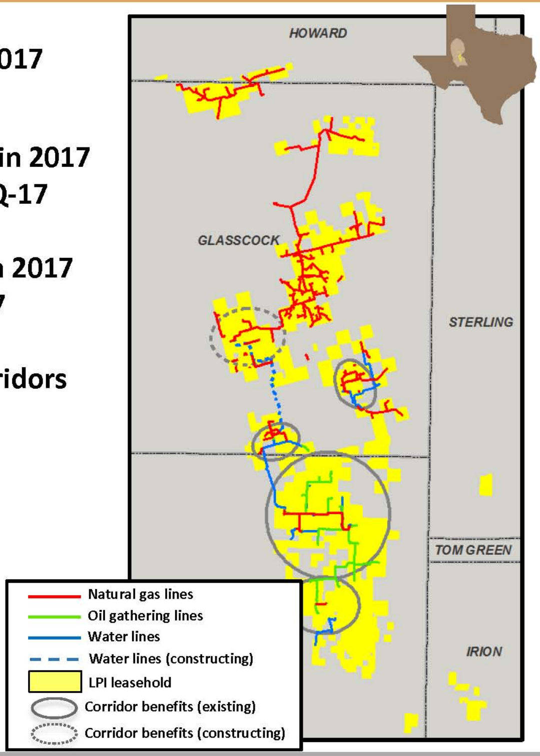
Testing Co-Development of Landing Points

Potential to add additional high-value inventory



Prior Investments in Infrastructure Providing Tangible Benefits

- Expect to receive $27.8 MM total benefits for 2017
  - ~$5.8 MM total benefits in 1Q-17[1]
- Anticipate reducing >100,000 water truckloads in 2017
  - Eliminated ~25,000 water truckloads in 1Q-17
- Anticipate reducing ~65,000 crude truckloads in 2017
  - Eliminated ~12,000 oil truckloads in 1Q-17
- ~200 horizontal wells served by production corridors with potential for >2,500 more[2]

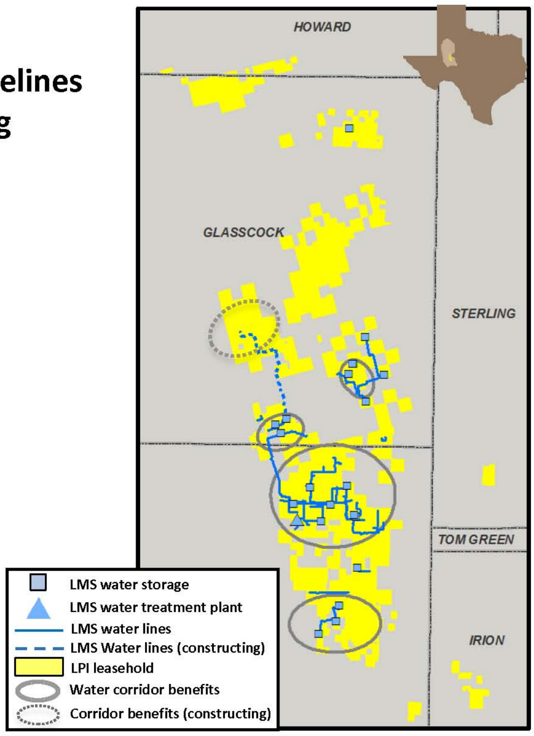


In 1Q-17, Laredo's infrastructure assets gathered on pipe 73% of gross operated oil production & 65% of total produced water

[1] Benefits defined as capital savings, LOE savings, price uplift and LMS net operating income
[2] Includes Western Glasscock production corridor, which is currently under construction
Note: Infrastructure includes crude gathering/transportation, water gathering, distribution & recycle, natural gas gathering and centralized gas lift compression

Significant Benefits through Water Infrastructure Investments

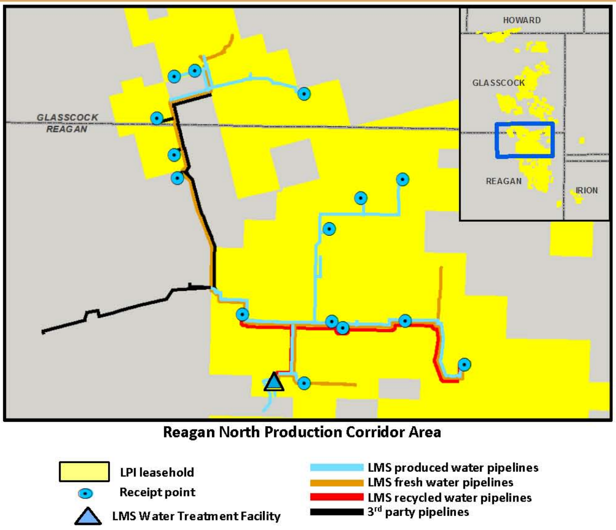
- Water infrastructure consists of:
  - 78 miles of total water gathering pipelines
  - Recycling plant capable of processing 30,000 BWPD
  - Linked water storage assets with >8 MMBW capacity
  - Total storage capacity of 12 MMBW
  - Access to ~340 wells with ~510,000 BWPD refresh rate
- Enables drilling of multi-well pads
- Yields significant capital and LOE savings
- Minimizes trucking



Water Infrastructure Capital and LOE Savings

- 3.1 MMBW (65%) of total 1Q-17 produced water was gathered on pipe
  - Expected to increase to ~75% for FY 2017
- 1.4 MMBW (30%) of total 1Q-17 produced water was recycled by LMS
  - Expected to increase to ~57% for FY 2017
- 3.5 MMBW (30%) of water for completions in 1Q-17 was supplied with recycled water
  - Expected to average ~20% in 2017

LMS Service	LPI Financial Benefits (1Q-17)		
	Category	($/BW)	($ MM)
Produced Water (Gathered vs Trucked)	Capital & LOE savings	$0.62	$1.9
Produced Water (Recycled vs Disposed)	Capital & LOE savings	$0.23	$0.3
Frac Water (Recycled vs Fresh)	Capital savings	$0.20	$0.7

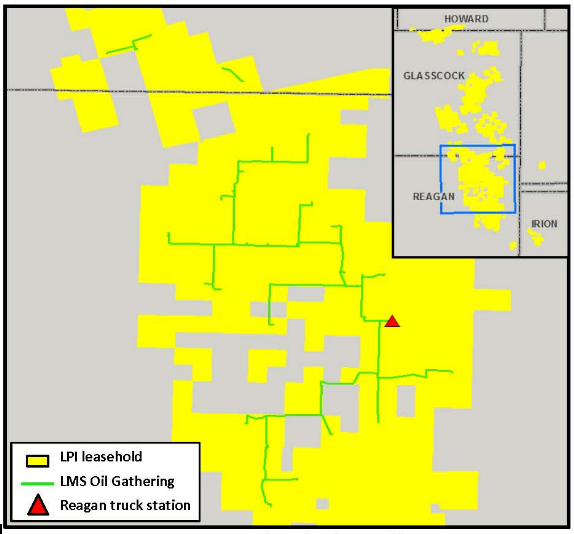


Reagan North Production Corridor Area

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

LMS Crude Gathering System Benefits

- 44 miles of crude oil gathering lines
- 2.2 MMBO (73%) of gross operated production in 1Q-17 was gathered on pipe
- Reduces time from production to sales
- Benefits of system increase as trucking costs rise



Reagan North Production Corridor Area

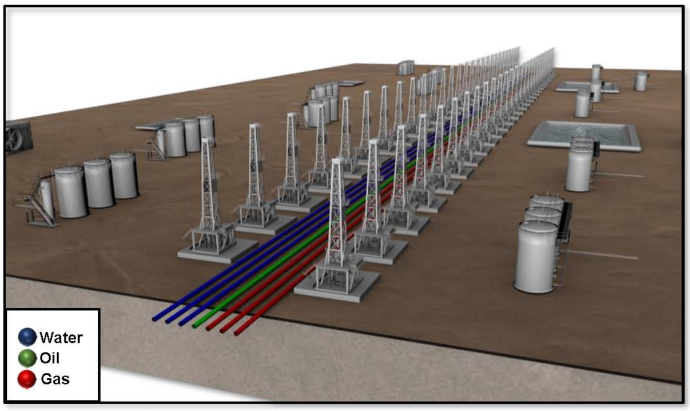
LMS Service	LPI Financial Benefits (1Q-17)		
	Category	($/Bbl)	($ MM)
Produced Oil (Gathered vs Trucked)	3rd-Party Income	$0.66	$1.5
Produced Oil (Gathered vs Trucked)	Increased Revenues	$0.55	$1.2

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

Note: 2017 estimates as of 5/1/2017

Corridor Financial Benefits

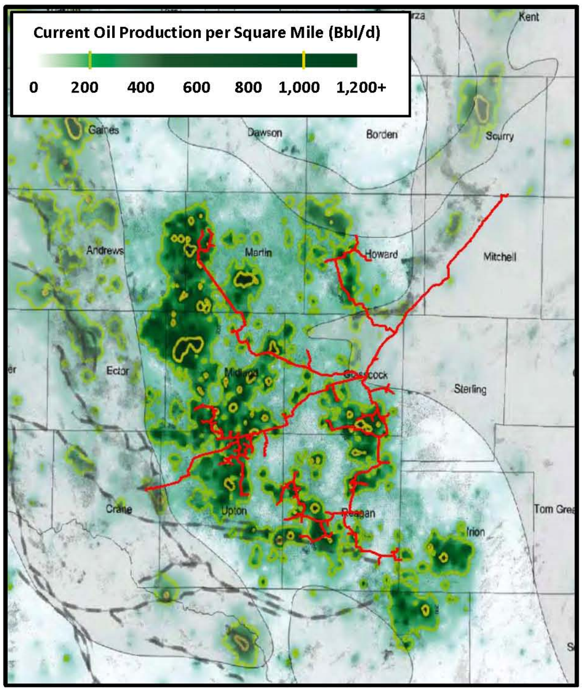
Production corridors reduced unit LOE by $0.46/BOE in 1Q-17 to $3.60/BOE



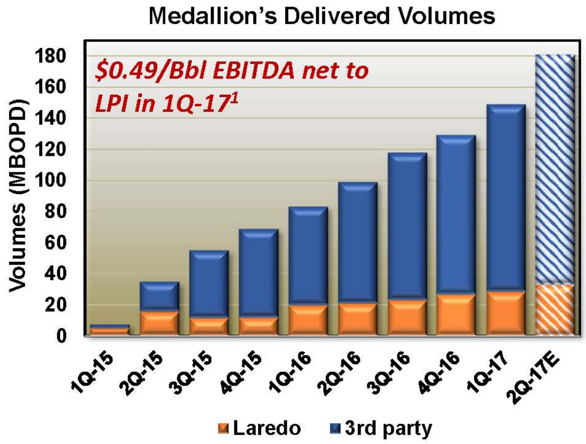
LMS Service	2016 Benefits Actual ($ MM)	1Q-17 Benefits Actual ($ MM)	2017 Benefits Estimated ($ MM)[1]	LPI Financial Benefits
Crude Gathering	$10.4	$2.7	$14.1	Increased revenues & 3rd-party income
Centralized Gas Lift	$0.9	$0.2	$1.0	LOE savings
Frac Water (Recycled vs Fresh)	$1.1	$0.7	$2.2	Capital savings
Produced Water (Recycled vs Disposed)	$2.0	$0.3	$2.1	Capital & LOE savings
Produced Water (Gathered vs Trucked)	$9.6	$1.9	$8.4	Capital & LOE savings
Corridor Benefit	**$24.1**	**$5.8**	**$27.8**	

[1] Benefits estimates as of 4/29/2017

Medallion-Midland Basin: The Premier Pipeline in the Permian



Medallion–Midland Basin system



The Medallion-Midland Basin system grew transported volumes 79% from 1Q-16 to 1Q-17

[1] Includes G&A

Note: Heat map generated by RS Energy Group, 2016

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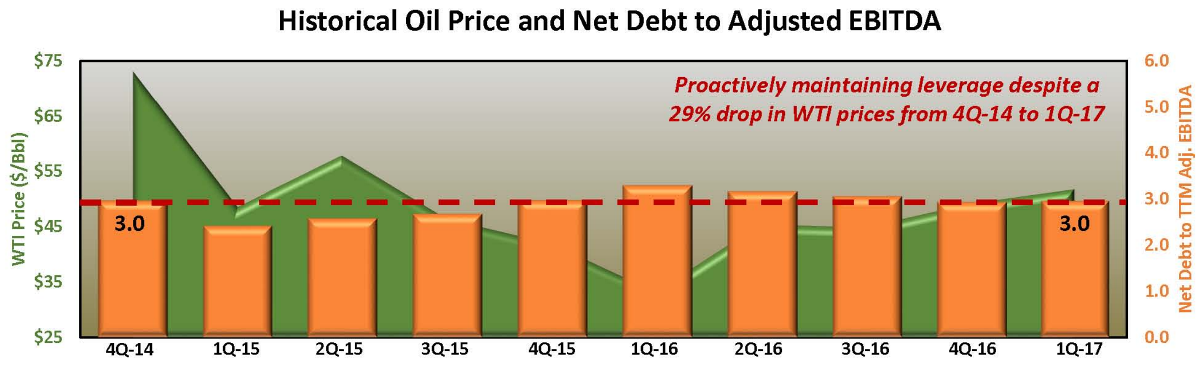
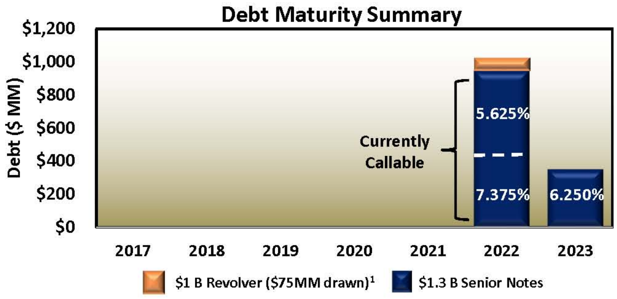
Maintaining Strong Financial Position



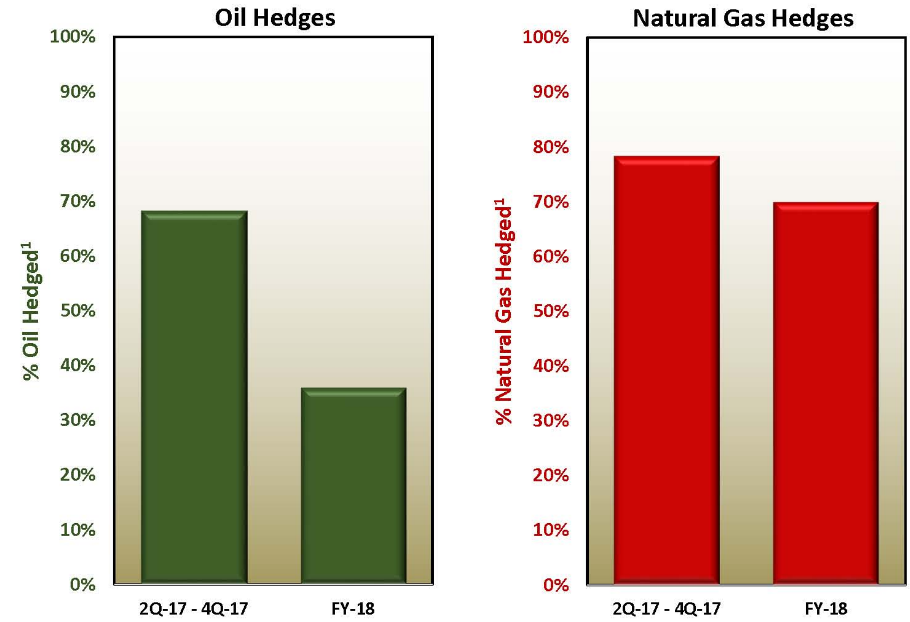
- **No debt due until 2022**
  - **$950 million of notes currently callable at Laredo's option**
- **$945 million of liquidity[1]**



[1] As of 5/2/17, with $1 B Borrowing Base in place with amended and restated Senior Secured Credit Facility

Disciplined Hedging Program

Volumes Protected by Floors



		2Q-17 - 4Q-17	FY-18
Oil: Weighted-Avg. Floor Price[2]	NYMEX	$55.82	$53.71
Natural Gas: Weighted-Avg. Floor Price[2]	WAHA	$2.75	$2.50
	HH[3]	$3.20	$2.95

Providing cash flow stability while retaining meaningful price upside opportunity

[1] For percent hedged, utilizing actual 2016 production plus 15% 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 $0.45/Mcf as of 05/02/17
Note: Does not include 2Q-17 - 4Q-17 NGL hedges of 333,000 Bbl of ethane or 281,250 Bbl of propane

LAREDO PETROLEUM

Oil, Natural Gas & Natural Gas Liquids Hedges

OIL[1]	2Q-17 - 4Q-17	2018
Puts:		
Hedged volume (Bbls)	790,625	1,779,375
Weighted average price ($/Bbl)	$60.00	$55.90
Swaps:		
Hedged volume (Bbls)	1,512,500	1,095,000
Weighted average price ($/Bbl)	$51.54	$52.12
Collars:		
Hedged volume (Bbls)	2,860,000	584,000
Weighted average floor price ($/Bbl)	$56.92	$50.00
Weighted average ceiling price ($/Bbl)	$86.00	$60.00
Total volume with a floor (Bbls)	5,163,125	3,458,375
Weighted-average floor price ($/Bbl)	$55.82	$53.71

NATURAL GAS[2]		
Put		
Hedged volume (MMBtu)	6,030,000	8,220,000
Weighted average floor price ($/MMBtu)	$2.50	$2.50
Collars:		
Hedged volume (MMBtu)	14,327,500	15,585,500
Weighted average floor price ($/MMBtu)	$2.86	$2.50
Weighted average ceiling price ($/MMBtu)	$3.54	$3.35
Total volume with a floor (MMBtu)	20,357,500	23,805,500
Weighted-average floor price ($/MMBtu)	$2.75	$2.50

NATURAL GAS LIQUIDS[3]		
Swaps - Ethane:		
Hedged volume (Bbls)	333,000	
Weighted average price ($/Bbl)	$11.24	
Swaps - Propane:		
Hedged volume (Bbls)	281,250	
Weighted average price ($/Bbl)	$22.26	
Total volume with a floor (Bbls)	614,250	

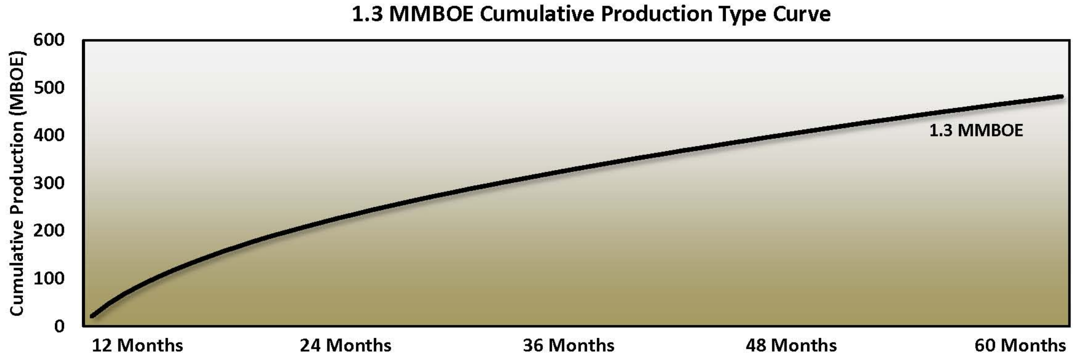
Note: Open positions as of 4/1/2017
[1] Oil derivatives are settled based on the month's average daily NYMEX price of WTI Light Sweet Crude Oil
[2] Natural gas derivatives are settled based on Inside FERC index price for West Texas Waha for the calculation period
[3] Natural gas liquids derivatives are settled based on the month's daily average of OPIS Mt. Belvieu Purity Ethane and TET Propane

2Q-17 Guidance

	2Q-17
Production (MBOE/d)........	55 - 58
Product % of total production:	
Crude oil........	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)........	~29%
Natural gas (% of Henry Hub)........	~68%
Operating Costs & Expenses:	
Lease operating expenses ($/BOE)........	$3.50 - $4.00
Midstream expenses ($/BOE)........	$0.20 - $0.30
Production and ad valorem taxes (% of oil, NGL and natural gas revenue)........	6.50%
General and administrative expenses:	
Cash ($/BOE)........	$3.00 - $3.50
Non-cash stock-based compensation ($/BOE)........	$1.75 - $2.00
Depletion, depreciation and amortization ($/BOE)........	$7.25 - $7.75

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 from the multivariate Earth Model optimized drilling and completions

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

2016 & 2017 YTD Actuals

		1Q-16	2Q-16	3Q-16	4Q-16	FY-16	1Q-17
Production	Production (3-Stream)						
	MBOE	4,204	4,338	4,718	4,889	18,149	4,716
	BOE/D	46,202	47,667	51,276	53,141	49,586	52,405
	% oil	48%	46%	46%	46%	47%	45%
Realized Pricing	3-Stream Prices						
	Gas ($/Mcf)	$1.31	$1.31	$2.07	$2.13	$1.73	$2.31
	NGL ($/Bbl)	$8.50	$12.24	$11.54	$14.79	$11.91	$16.49
	Oil ($/Bbl)	$27.51	$39.37	$39.10	$43.98	$37.73	$46.91
	Avg. Price ($/BOE)	$17.40	$23.64	$24.34	$27.82	$23.50	$29.42
Unit Cost Metrics	3-Stream Unit Cost Metrics						
	Lease Operating ($/BOE)	$4.88	$4.43	$3.85	$3.56	$4.15	$3.60
	Midstream ($/BOE)	$0.14	$0.27	$0.22	$0.26	$0.22	$0.19
	General & Administrative ($/BOE)						
	Cash	$3.72	$3.32	$3.49	$3.28	$3.45	$3.47
	Non-cash stock-based compensation	$0.91	$1.41	$2.05	$1.98	$1.61	$1.96
	DD&A ($/BOE)	$9.87	$7.88	$7.45	$7.68	$8.17	$7.23

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	$26.41
Unit Cost Metrics	3-Stream Unit Cost Metrics						
	Lease Operating ($/BOE)		$7.58	$6.90	$6.09	$5.83	$6.63
	Midstream ($/BOE)		$0.37	$0.38	$0.26	$0.43	$0.36
	General & Administrative ($/BOE)						
	Cash		$3.99	$3.99	$3.89	$4.29	$4.03
	Non-cash stock-based compensation		$1.12	$1.49	$1.67	$1.75	$1.50
	DD&A ($/BOE)		$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	2,902	3,113	3,614	4,330	13,959
	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	$52.81
Unit Cost Metrics	2-Stream Unit Cost Metrics					
	Lease Operating ($/BOE)	$8.95	$7.74	$8.30	$8.04	$8.23
	Midstream ($/BOE)	$0.35	$0.59	$0.40	$0.50	$0.46
	General & Administrative ($/BOE)					
	Cash	$9.58	$8.88	$6.89	$4.25	$7.07
	Non-cash stock-based compensation	$1.78	$2.46	$2.04	$1.70	$1.97
	DD&A ($/BOE)	$20.38	$20.35	$21.08	$21.85	$21.01
	3-Stream Unit Cost Metrics					
	Lease Operating ($/BOE)	$7.48	$6.55	$7.05	$6.88	$6.98
	Midstream ($/BOE)	$0.29	$0.50	$0.34	$0.43	$0.39
	General & Administrative ($/BOE)					
	Cash	$8.05	$7.44	$5.78	$3.59	$5.94
	Non-cash stock-based compensation	$1.48	$2.06	$1.72	$1.43	$1.65
	DD&A ($/BOE)	$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)*		1Q-17
Net income	$	68,276
Plus:		
Depletion, depreciation and amortization	$	34,112
Impairment expense	$	-
Non-cash stock-based compensation, net of amounts capitalized	$	9,224
Accretion expense	$	928
Mark-to-market on derivatives:		
Gain on derivatives, net	$	(36,671)
Cash settlements received for matured derivatives, net	$	7,451
Cash settlements received for early termination of derivatives, net	$	-
Cash premiums paid for derivatives	$	(2,107)
Interest expense	$	22,720
Loss on disposal of assets, net	$	214
Income from equity method investee	$	(3,068)
Proportionate Adjusted EBITDA of equity method investee[1]	$	6,365
Adjusted EBITDA	$	107,444

[1]Medallion Adjusted EBITDA *(in thousands)*		1Q-17
Income from equity method investee	$	3,068
Adjusted for proportionate share of:		
Depreciation and amortization	$	3,297
Proportionate Adjusted EBITDA of equity method investee	$	6,365