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 3, 2016

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 August 3, 2016, Laredo Petroleum, Inc. (the "Company") announced its financial and operating results for the quarter ended June 30, 2016. 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 August 4, 2016, at 7:30 a.m. Central Time to discuss these results and management's outlook. To access the call, please dial 1-877-930-8286 or 1-253-336-8309 for international callers, and use conference code 49616756. A replay of the call will be available through Thursday, August 11, 2016, by dialing 1-855-859-2056, and using conference code 49616756. The webcast may be accessed at the Company's website, www.laredopetro.com, under the tab "Investor Relations."

In accordance with General Instruction B.2 of the Form 8-K, the information furnished under this Item 2.02 of this Current Report on Form 8-K and the exhibits attached hereto are deemed to be "furnished" and shall not be deemed "filed" for the purpose of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liabilities of that section, nor shall such information and 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 3, 2016, 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 3, 2016, the Company also posted to its website certain financial and operating results and other information regarding the Company (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 the 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 in 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 3, 2016.
99.2	Presentation dated August 3, 2016.

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 3, 2016	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 3, 2016.
99.2	Presentation dated August 3, 2016.

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 2016 Second-Quarter Financial and Operating Results

Raises Estimated 2016 Production to 17.0 - 17.3 Million BOE

TULSA, OK - August 3, 2016 - Laredo Petroleum, Inc. (NYSE: LPI) ("Laredo" or "the Company") today announced its 2016 second-quarter results, reporting a net loss attributable to common stockholders of $71.4 million, or $0.33 per diluted share, which includes a net loss on derivatives of approximately $68.5 million. Adjusted Net Income, a non-GAAP financial measure, for the second quarter of 2016 was $28.2 million, or $0.13 per diluted share. Adjusted EBITDA, a non-GAAP financial measure, for the second quarter of 2016 was $107.8 million. Please see supplemental financial information at the end of this news release for reconciliations of non-GAAP financial measures.

2016 Second-Quarter Highlights

- Produced a Company record 47,667 barrels of oil equivalent ("BOE") per day and increased anticipated production for full-year 2016 to a range midpoint of 17.15 million BOE, up 5.5% from the 16.25 million BOE midpoint of the Company's previous increased guidance and up approximately 11% from the original 2016 guidance midpoint of 15.5 million BOE
- Completed 16 horizontal wells with an average completed lateral length of approximately 9,700 feet, 10 of which have reached their peak 30-day initial production ("IP") rates, averaging 1,147 BOE per day, or 135% of type curve
- Reduced unit lease operating expenses ("LOE") to $4.43 per BOE, down approximately 36% from the second-quarter 2015 rate of $6.90 per BOE
- Recognized more than $6.4 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 to 99,039 barrels of oil per day ("BOPD"), an increase from 34,600 BOPD in the second quarter of 2015
- Received approximately $45.0 million of net cash settlements, net of premiums paid, on commodity derivatives that matured during second-quarter 2016, increasing the average sales price for oil by $19.49 per barrel and for natural gas by $0.82 per thousand cubic feet compared to pre-hedged average sales prices

"Positive results of multiple catalysts from prior investments are driving record production volumes delivered at peer-leading unit production costs and significantly improving the Company's capital investment efficiency," commented Randy A. Foutch, Chairman and Chief Executive Officer. "These investments in data collection, reservoir modeling, infrastructure, product takeaway and actual well testing provide a strong foundation for Laredo to continue to economically enhance value for stakeholders even in challenging industry cycles. Also, our strong hedge position provides further support to mitigate commodity price volatility and we have maintained financial flexibility with current liquidity of approximately $760 million and no public debt maturing for more than five years."

Operational Update

In the second quarter of 2016, Laredo produced a Company record 47,667 BOE per day, of which approximately 73% was oil and natural gas liquids ("NGL"). Production during the quarter demonstrated the positive impact of the Company's long-term initiatives to collect data and invest in infrastructure to improve capital efficiency. The Earth Model coupled with optimized completions was utilized in all wells completed in second-quarter 2016, driving consistent outperformance versus the Company's type curves. Additionally, investments in field infrastructure and centralized facilities along the Company's production corridors enabled more efficient operations, resulting in higher production uptime and reducing the time to sales for produced oil.

Laredo's field infrastructure investments continue to drive operating costs lower as more wells are drilled along the Company's production corridors. In the second quarter of 2016, total LOE decreased approximately 34% from the second quarter of 2015, even as production grew, and unit LOE decreased approximately 36% from the prior-year quarter to a peer-leading rate of $4.43 per BOE. In addition to benefiting from previous infrastructure investments, LOE was positively impacted by steps taken to continuously improve field operations. Procedures to optimize and reduce chemicals usage, an enhanced SCADA production monitoring system, optimized water management and a proactive workover program all contributed to the approximately 42% reduction in unit LOE since the beginning of 2015.

Continued improvement in the Company's pacesetting drilling operations benefited Laredo's capital efficiency. In the second quarter of 2016, Laredo operated three horizontal rigs that drilled an average of 990 feet per day from rig acceptance to rig release, an improvement of approximately 66% from the second quarter of 2015. These efficiencies have reduced the average number of days to drill a well by approximately 36% from the second quarter of 2015, even as the Company has extended the majority of its laterals to 10,000 feet and longer.

Laredo is seeing continued improvement in well costs driven by a combination of an intense focus on drilling efficiencies and on deriving the maximum value from its service providers. On average, the Company's well cost for 10,000-foot laterals in the Upper and Middle Wolfcamp that utilize optimized completions are approximately $6.3 million, but the Company's most recent costs are trending to the mid $5 million level.

The Company completed 16 horizontal development wells during the second quarter of 2016, five of which began flowback in the last half of June and had minimal impact on production during the quarter. These 16 wells have an average lateral length of approximately 9,700 feet and a working interest of 100%. The Company's proprietary Earth Model was used on each of these wells to land and steer the lateral and aid in optimizing completions. Ten of the 16 wells have achieved peak 30-day average IP rates with the average of those 10 wells performing 35% above type curve. The results of these 10 wells are detailed in the following table.

Well Name	Zone	Completed Lateral Length (feet)	30-Day Average IP (BOE)	% of Type Curve(1)
Sugg-E-197-198-5NU	Upper WC	7,371	1,089	153%
Sugg-E-197-198-6NU	Upper WC	7,438	959	134%
LPI-Cox-21-16-4NU	Upper WC	9,892	1,038	110%
Cox-21-16-5NU	Upper WC	9,853	950	101%
Cox-21-16-7NU	Upper WC	9,936	987	104%
Cox-21-16-8NU	Upper WC	9,936	887	94%
Holt-C-132-130-4NM	Middle WC	10,491	1,381	159%
Holt-C-132-130-8NM	Middle WC	10,671	1,355	153%
Holt-C-132-133-4SM	Middle WC	9,757	1,329	164%
Holt-C-132-133-8SM	Middle WC	9,937	1,494	181%
2Q-16 Average			**1,147**	**135%**

(1) Adjusted for lateral length

The Company is currently operating three horizontal rigs and anticipates completing 10 horizontal development wells during the third quarter of 2016, with an average working interest of approximately 99%. Nine of the wells target the Upper and Middle Wolfcamp and one the Cline shale. The wells are expected to have an average lateral length of approximately 11,000 feet, including four that are at least 13,000 feet, as the Company continues to benefit from its contiguous acreage position that enables the drilling of more capital efficient longer laterals.

The Company expects to move one of its three operated rigs to the Western Glasscock production corridor position during the third quarter of 2016 and anticipates accelerating development of this acreage in 2017.

Laredo Midstream Services Update

Laredo's field infrastructure and production corridor assets continue to reduce operational costs and have increasing cash benefits to the Company. Savings from transporting water by pipe, water recycling and centralized gas lift reduced unit LOE in the second quarter of 2016 by approximately 14%, or $0.72 per BOE. As utilization of these assets has increased, the total cash benefit to Laredo for the second quarter of 2016 was approximately $6.4 million. LMS' crude and natural gas gathering systems transported approximately 60% of the Company's gross operated crude oil production during the quarter and approximately 58% of gross operated natural gas production. LMS' water gathering and treatment systems gathered 58% of flowback and produced water by pipe and 22% of water used in second-quarter 2016 completions was fulfilled with recycled water from LMS' water recycling facility.

The Medallion Gathering & Processing, LLC pipeline system ("Medallion-Midland Basin"), in which LMS owns a 49% interest, continued to grow transported volumes at a rapid pace. Transported volumes in the second quarter of 2016 increased to an average of 99,039 BOPD, an increase of approximately 186% from the second quarter of 2015 and up approximately 19% compared to the first quarter of 2016. The Medallion-Midland Basin system is expected to transport an average of approximately 120,000 BOPD in the third quarter of 2016.

2016 Capital Program

During the second quarter of 2016, Laredo invested approximately $80 million in exploration and development activities, approximately $11 million in a previously announced bolt-on land acquisition and approximately $15 million in infrastructure held by LMS, including the Medallion-Midland Basin pipeline system.

Liquidity

At June 30, 2016, the Company had cash and equivalents of approximately $19 million and undrawn capacity under the senior secured credit facility of approximately $705 million, resulting in total liquidity of approximately $724 million. At August 2, 2016, the Company had cash and equivalents of approximately $15 million and undrawn capacity under the senior secured credit facility of approximately $745 million, resulting in total liquidity of approximately $760 million.

Commodity Derivatives

Laredo maintains an active hedging program to reduce the variability in its anticipated cash flow due to fluctuations in commodity prices while retaining meaningful upside to commodity prices. At June 30, 2016, the Company had hedges in place for the remaining two quarters of 2016 for 3,722,700 barrels of oil at a weighted-average floor price of $67.13 per barrel, representing approximately 95% of anticipated oil production for the remainder of 2016, and 9,384,000 million British thermal units ("MMBtu") of natural gas at a weighted-average floor price of $3.00 per MMBtu, representing approximately 65% of anticipated natural gas production for 2016.

At June 30, 2016, for 2017, the Company had hedged 3,677,375 barrels of oil at a weighted-average floor price of $60.00 per barrel and 18,771,000 MMBtu of natural gas at a weighted-average floor price of $2.65 per MMBtu. Subsequently, the Company hedged an additional 2,007,500 barrels of oil for 2017 and currently has 5,684,875 barrels of oil hedged for 2017 at a weighted-average floor price of $57.01 per barrel. Additionally, the Company hedged 444,000 barrels of ethane for 2017 at $11.24 per barrel and 375,000 barrels of propane for 2017 at $22.26 per barrel.

At June 30, 2016, for 2018, the Company had hedged 2,144,375 barrels of oil at a weighted-average floor price of $55.98 per barrel and 12,855,500 MMBtu of natural gas at a weighted-average floor price of $2.50 per MMBtu.

Increased 2016 Production Guidance and Third-Quarter 2016 Guidance

The Company is increasing full-year 2016 production guidance under its current budget from a range of 16.1-16.4 million BOE to 17.0-17.3 million BOE.

The table below reflects the Company's guidance for the third quarter of 2016:

	3Q-2016
Production (MMBOE)	4.2 - 4.4
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)	~85%
Natural gas liquids (% of WTI)	~25%
Natural gas (% of Henry Hub)	~70%
Operating Costs & Expenses:	
Lease operating expenses ($/BOE)	$4.25 - $4.75
Midstream expenses ($/BOE)	$0.15 - $0.35
Production and ad valorem taxes (% of oil, NGL and natural gas revenue)	8.25%
General and administrative expenses:	
General and administrative - cash ($/BOE)	$3.00 - $3.75
General and administrative - non-cash stock-based compensation ($/BOE)	$2.25 - $3.00
Depletion, depreciation and amortization ($/BOE)	$8.00 - $9.00

Conference Call Details

On Thursday, August 4, 2016, at 7:30 a.m. CT, Laredo will host a conference call to discuss its second-quarter 2016 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." Individuals who would like to participate on the call should dial 877.930.8286, using conference code 49616756, approximately 10 minutes prior to the scheduled conference time. International participants should dial 253.336.8309, also using conference code 49616756. A telephonic replay will be available approximately two hours after the call on August 4, 2016 through Thursday, August 11, 2016. Participants may access this replay by dialing 855.859.2056, using conference code 49616756.

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 transportation of oil and 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, contains forward-looking statements as defined under Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, that address activities that Laredo 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, 2015, 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 June 30, 2016	Three months ended June 30, 2015	Six months ended June 30, 2016	Six months ended June 30, 2015
	(unaudited)		(unaudited)	
Revenues:				
Oil, NGL and natural gas sales	$ 102,526	$ 125,554	$ 175,668	$ 243,672
Midstream service revenues	1,632	1,726	3,433	3,035
Sales of purchased oil	42,615	55,051	74,229	86,318
Total revenues	146,773	182,331	253,330	333,025
Costs and expenses:				
Lease operating expenses	19,225	29,206	39,743	61,586
Production and ad valorem taxes	7,982	9,500	14,417	18,586
Midstream service expenses	1,178	1,597	1,787	3,171
Minimum volume commitments	—	3,579	—	5,235
Costs of purchased oil	44,012	54,417	76,958	85,617
General and administrative	20,502	23,208	39,953	45,063
Restructuring expenses	—	—	—	6,042
Accretion of asset retirement obligations	860	593	1,704	1,172
Depletion, depreciation and amortization	34,177	72,112	75,655	144,054
Impairment expense	963	489,599	162,027	490,477
Total costs and expenses	128,899	683,811	412,244	861,003
Operating income (loss)	17,874	(501,480)	(158,914)	(527,978)
Non-operating income (expense):				
Loss on derivatives, net	(68,518)	(63,899)	(50,633)	(744)
Income from equity method investee	3,696	2,914	5,994	2,481
Interest expense	(23,512)	(23,970)	(47,217)	(56,384)
Loss on early redemption of debt	—	(31,537)	—	(31,537)
Other, net	(972)	(908)	(1,033)	(1,547)
Non-operating expense, net	(89,306)	(117,400)	(92,889)	(87,731)
Loss before income taxes	(71,432)	(618,880)	(251,803)	(615,709)
Income tax benefit:				
Deferred	—	221,846	—	218,203
Total income tax benefit	—	221,846	—	218,203
Net loss	$ (71,432)	$ (397,034)	$ (251,803)	$ (397,506)
Net loss per common share:				
Basic	$ (0.33)	$ (1.88)	$ (1.17)	$ (2.13)
Diluted	$ (0.33)	$ (1.88)	$ (1.17)	$ (2.13)
Weighted-average common shares outstanding:				
Basic	217,564	211,078	214,562	186,886
Diluted	217,564	211,078	214,562	186,886

Laredo Petroleum, Inc.
Condensed consolidated balance sheets

(in thousands)	June 30, 2016	December 31, 2015
Assets:	(unaudited)	(unaudited)
Current assets	$ 211,262	$ 332,232
Net property and equipment	1,144,179	1,200,255
Other noncurrent assets	254,710	280,800
Total assets	$ 1,610,151	$ 1,813,287
Liabilities and stockholders' equity:		
Current liabilities	$ 153,812	$ 216,815
Long-term debt, net	1,392,877	1,416,226
Other noncurrent liabilities	54,300	48,799
Stockholders' equity	9,162	131,447
Total liabilities and stockholders' equity	$ 1,610,151	$ 1,813,287

Laredo Petroleum, Inc.
Condensed consolidated statements of cash flows

(in thousands)	Three months ended June 30, 2016	Three months ended June 30, 2015	Six months ended June 30, 2016	Six months ended June 30, 2015
	(unaudited)		(unaudited)	
Cash flows from operating activities:				
Net loss	$ (71,432)	$ (397,034)	$ (251,803)	$ (397,506)
Adjustments to reconcile net loss to net cash provided by operating activities:				
Deferred income tax benefit	—	(221,846)	—	(218,203)
Depletion, depreciation and amortization	34,177	72,112	75,655	144,054
Impairment expense	963	489,599	162,027	490,477
Loss on early redemption of debt	—	31,537	—	31,537
Non-cash stock-based compensation, net of amounts capitalized	6,073	6,268	9,911	11,056
Mark-to-market on derivatives:				
Loss on derivatives, net	68,518	63,899	50,633	744
Cash settlements received for matured derivatives, net	47,382	46,596	113,319	109,737
Cash settlements received for early terminations of derivatives, net	—	—	80,000	—
Cash premiums paid for derivatives	(2,413)	(1,249)	(84,263)	(2,670)
Amortization of debt issuance costs	1,067	1,124	2,187	2,501
Other, net	(1,790)	(1,166)	(9,404)	(2,119)
Cash flows from operations before changes in working capital	82,545	89,840	148,262	169,608
Changes in working capital	(304)	(3,209)	(9,435)	(57,295)
Changes in other noncurrent liabilities and fair value of performance unit awards	(127)	809	(196)	1,992
Net cash provided by operating activities	82,114	87,440	138,631	114,305
Cash flows from investing activities:				
Capital expenditures:				
Oil and natural gas properties	(91,887)	(130,775)	(197,042)	(374,508)
Midstream service assets	(1,488)	(13,703)	(3,425)	(34,137)
Other fixed assets	(202)	(2,622)	(832)	(6,541)
Investment in equity method investee	(16,021)	—	(42,681)	(14,495)
Proceeds from dispositions of capital assets, net of costs	132	—	350	35
Net cash used in investing activities	(109,466)	(147,100)	(243,630)	(429,646)
Cash flows from financing activities:				
Borrowings on Senior Secured Credit Facility	35,000	125,000	120,000	300,000
Payments on Senior Secured Credit Facility	(119,682)	—	(144,682)	(475,000)
Issuance of March 2023 Notes	—	—	—	350,000
Redemption of January 2019 Notes	—	(576,200)	—	(576,200)
Proceeds from issuance of common stock, net of offering costs	119,310	—	119,310	754,163
Other, net	(62)	(640)	(1,474)	(9,350)
Net cash provided by (used in) financing activities	34,566	(451,840)	93,154	343,613
Net increase (decrease) in cash and cash equivalents	7,214	(511,500)	(11,845)	28,272
Cash and cash equivalents, beginning of period	12,095	569,093	31,154	29,321
Cash and cash equivalents, end of period	$ 19,309	$ 57,593	$ 19,309	$ 57,593

Laredo Petroleum, Inc.
Selected operating data

	Three months ended June 30,		Six months ended June 30,	
	2016	**2015**	**2016**	**2015**
	(unaudited)		(unaudited)	
Sales volumes:				
Oil (MBbl)	2,012	1,938	4,018	4,110
NGL (MBbl)	1,153	1,095	2,219	2,084
Natural gas (MMcf)	7,038	7,205	13,834	13,885
Oil equivalents (MBOE)[1][2]	4,338	4,234	8,542	8,508
Average daily sales volumes (BOE/D)[2]	47,667	46,532	46,935	47,007
% Oil	46%	46%	47%	48%
Average sales prices:				
Oil, realized ($/Bbl)[3]	$ 39.37	$ 50.77	$ 33.45	$ 45.99
NGL, realized ($/Bbl)[3]	$ 12.24	$ 12.85	$ 10.44	$ 13.08
Natural gas, realized ($/Mcf)[3]	$ 1.31	$ 1.82	$ 1.31	$ 1.97
Average price, realized ($/BOE)[3]	$ 23.64	$ 29.65	$ 20.56	$ 28.64
Oil, hedged ($/Bbl)[4]	$ 58.86	$ 72.39	$ 57.85	$ 70.87
NGL, hedged ($/Bbl)[4]	$ 12.24	$ 12.85	$ 10.44	$ 13.08
Natural gas, hedged ($/Mcf)[4]	$ 2.13	$ 2.29	$ 2.10	$ 2.32
Average price, hedged ($/BOE)[4]	$ 34.00	$ 40.36	$ 33.33	$ 41.22
Average costs per BOE sold:				
Lease operating expenses	$ 4.43	$ 6.90	$ 4.65	$ 7.24
Production and ad valorem taxes	1.84	2.24	1.69	2.18
Midstream service expenses	0.27	0.38	0.21	0.37
General and administrative[5]	4.73	5.48	4.68	5.30
Depletion, depreciation and amortization	7.88	17.03	8.86	16.93
Total	$ 19.15	$ 32.03	$ 20.09	$ 32.02

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

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

(3) Realized oil, NGL and natural gas prices are the actual prices 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. The prices presented are based on actual results and are not calculated using the rounded numbers presented in the table above.

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

(5) General and administrative includes non-cash stock-based compensation, net of amounts capitalized, of $6.1 million and $6.3 million for the three months ended June 30, 2016 and 2015, respectively, and $9.9 million and $11.1 million for the six months ended June 30, 2016 and 2015, respectively.

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)	**2016**	**2015**	**2016**	**2015**
	(unaudited)		(unaudited)	
Property acquisition costs:				
Evaluated	$ —	$ —	$ —	$ —
Unevaluated	—	—	—	—
Exploration	19,769	3,841	27,032	8,354
Development costs[(1)]	70,806	110,518	152,692	317,190
Total costs incurred	$ 90,575	$ 114,359	$ 179,724	$ 325,544

(1) The costs incurred for oil, NGL and natural gas development activities include $0.1 million and $0.5 million in asset retirement obligations for the three months ended June 30, 2016 and 2015, respectively, and $0.2 million and $1.0 million for the six months ended June 30, 2016 and 2015, respectively.

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, gains or losses on derivatives, cash settlements of matured derivatives, cash settlements on early terminated derivatives, premiums paid for derivatives, impairment expense, restructuring expenses, loss on early redemption of debt, buyout of minimum volume commitment, gains or losses on disposal of assets, write-off of debt issuance costs and bad debt expense 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. At December 31, 2015 we changed the methodology for calculating Adjusted Net Income by applying a tax rate of 36% to all periods. As such, the prior periods' Adjusted Net Income has been modified for comparability.

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

	Three months ended June 30,		Six months ended June 30,	
(in thousands, except for per share data, unaudited)	**2016**	**2015**	**2016**	**2015**
Net loss	$ (71,432)	$ (397,034)	$ (251,803)	$ (397,506)
Plus:				
Deferred income tax benefit	—	(221,846)	—	(218,203)
Mark-to-market on derivatives:				
Loss on derivatives, net	68,518	63,899	50,633	744
Cash settlements received for matured derivatives, net	47,382	46,596	113,319	109,737
Cash settlements received for early terminations of derivatives, net	—	—	80,000	—
Premiums paid for derivatives	(2,413)	(1,249)	(84,263)	(2,670)
Impairment expense	963	489,599	162,027	490,477
Restructuring expenses	—	—	—	6,042
Loss on early redemption of debt	—	31,537	—	31,537
Buyout of minimum volume commitment	—	3,014	—	3,014
Loss on disposal of assets, net	141	1,081	301	1,843
Write-off of debt issuance costs	842	—	842	—
	44,001	15,597	71,056	25,015
Adjusted income tax expense[(1)]	(15,840)	(5,615)	(25,580)	(9,005)
Adjusted Net Income	$ 28,161	$ 9,982	$ 45,476	$ 16,010
Net loss per common share:				
Basic	$ (0.33)	$ (1.88)	$ (1.17)	$ (2.13)
Diluted	$ (0.33)	$ (1.88)	$ (1.17)	$ (2.13)
Adjusted Net Income per common share:				
Basic	$ 0.13	$ 0.05	$ 0.21	$ 0.09
Diluted	$ 0.13	$ 0.05	$ 0.21	$ 0.09
Weighted-average common shares outstanding:				
Basic	217,564	211,078	214,562	186,886
Diluted	217,564	211,078	214,562	186,886

(1) Adjusted income tax expense is calculated by applying a tax rate of 36% for each of the three and six months ended June 30, 2016 and 2015.

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, bad debt expense, impairment expense, non-cash stock-based compensation, restructuring expenses, gains or losses on derivatives, cash settlements received for matured derivatives, cash settlements on early terminated derivatives, premiums paid for derivatives, interest expense, write-off of debt issuance costs, gains or losses on disposal of assets, loss on early redemption of debt and buyout of minimum volume commitment. 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.

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

	Three months ended June 30,		Six months ended June 30,	
(in thousands, unaudited)	**2016**	**2015**	**2016**	**2015**
Net loss	$ (71,432)	$ (397,034)	$ (251,803)	$ (397,506)
Plus:				
Deferred income tax benefit	—	(221,846)	—	(218,203)
Depletion, depreciation and amortization	34,177	72,112	75,655	144,054
Impairment expense	963	489,599	162,027	490,477
Non-cash stock-based compensation, net of amounts capitalized	6,073	6,268	9,911	11,056
Restructuring expenses	—	—	—	6,042
Mark-to-market on derivatives:				
Loss on derivatives, net	68,518	63,899	50,633	744
Cash settlements received for matured derivatives, net	47,382	46,596	113,319	109,737
Cash settlements received for early terminations of derivatives, net	—	—	80,000	—
Premiums paid for derivatives	(2,413)	(1,249)	(84,263)	(2,670)
Interest expense	23,512	23,970	47,217	56,384
Write-off of debt issuance costs	842	—	842	—
Loss on disposal of assets, net	141	1,081	301	1,843
Loss on early redemption of debt	—	31,537	—	31,537
Buyout of minimum volume commitment	—	3,014	—	3,014
Adjusted EBITDA	$ 107,763	$ 117,947	$ 203,839	$ 236,509

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16-17

EXHIBIT 99.2

LAREDO
PETROLEUM

2016 Second-Quarter Financial and Operating Results

August 2016

Forward-Looking / Cautionary Statements

This presentation, including oral statements made in connection herewith, 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, 2015 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.

2Q-16 Highlights

- Produced a Company record 47,667 BOE/d, exceeding the top end of updated production guidance
- Increased anticipated full-year 2016 production to a range midpoint of 17.15 MBOE, up ~5.5% from prior guidance midpoint of 16.25 MBOE
- Completed 16 Hz wells with an average completed lateral length of ~9,700', with 10 wells reaching peak 30-day IP rates that averaged 135% of type curve
- Reduced unit LOE by 36% YoY to $4.43/BOE from $6.90/BOE in 2Q-15
- Grew transported oil on the Medallion pipeline system to 99,039 BOPD, increasing from 34,600 BOPD in 2Q-15
- Recognized >$6.4 MM of cash benefits from prior LMS field infrastructure investments through reduced costs and increased revenue
- Received $45 MM of net cash settlements on commodity derivatives, net of premiums paid, increasing the average realized sales price by $19.49/Bbl for oil and $0.82/Mcf for natural gas

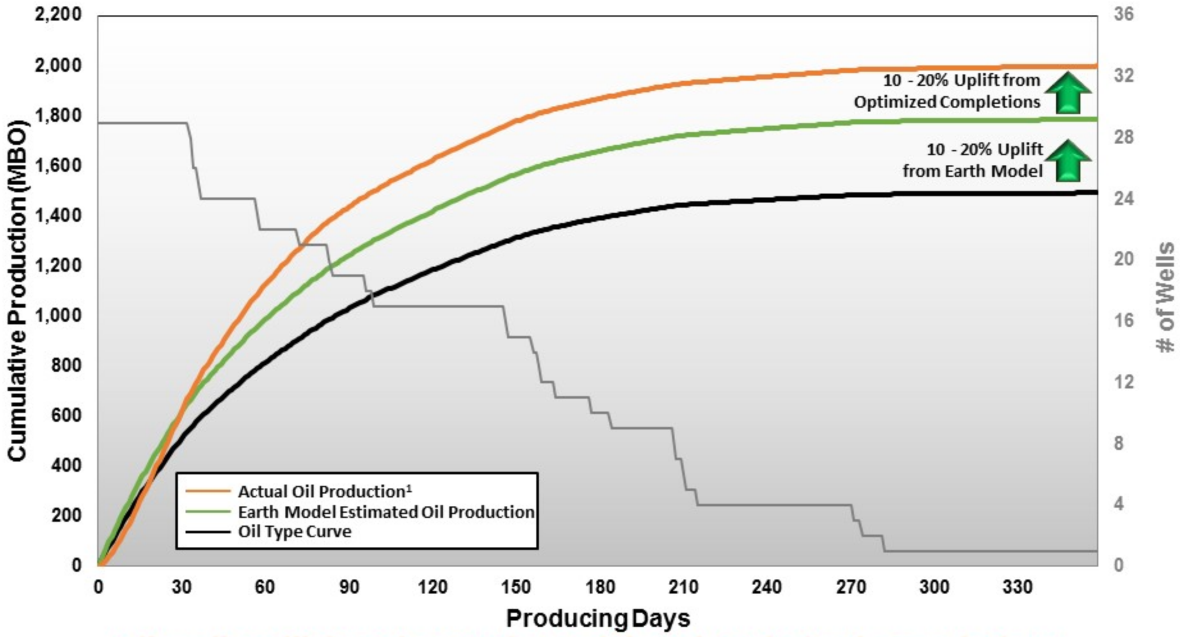
2Q-16 Operational Achievements

- **Produced >47.7 MBOE/d, ~46% oil**
  - **3% BOE/d beat to updated guidance midpoint**
- **Invested ~$80 MM in exploration and development capital[1] and increased FY-16 production guidance**
- **Completed 16 Hz wells with 100% working interest in multiple zones, 10 of which have achieved peak 30-day average IP rates exceeding type curve by an average of 35%**

Well Name[2]	Zone	Completed Lateral Length (Ft)	30-Day Average IP (BOE)	% of Type Curve[3]
Sugg-E-197-198-5NU	UWC	7,371	1,089	153%
Sugg-E-197-198-6NU	UWC	7,438	959	134%
LPI-Cox-21-16-4NU	UWC	9,892	1,038	110%
Cox-21-16-5NU	UWC	9,853	950	101%
Cox-21-16-7NU	UWC	9,936	987	104%
Cox-21-16-8NU	UWC	9,936	887	94%
Holt-C-132-130-4NM	MWC	10,491	1,381	159%
Holt-C-132-130-8NM	MWC	10,671	1,355	153%
Holt-C-132-133-4SM	MWC	9,757	1,329	164%
Holt-C-132-133-8SM	MWC	9,937	1,494	181%
2Q-16 AVERAGE			1,147	135%

[1] Excludes previously-announced $11 MM bolt-on acquisition. Total 2Q-16 exploration & development capital is $91 MM
[2] Only includes wells completed in the quarter that have achieved peak 30-day rates
[3] Adjusted for lateral length

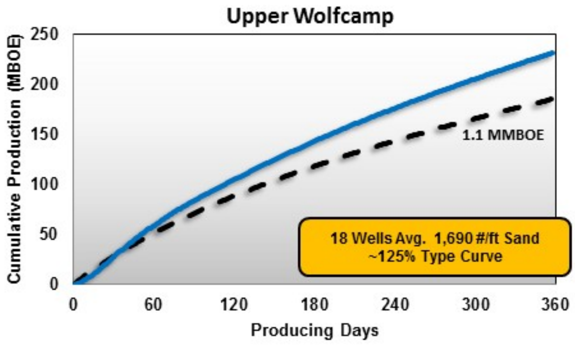
Earth Model and Optimized Completions Benefits

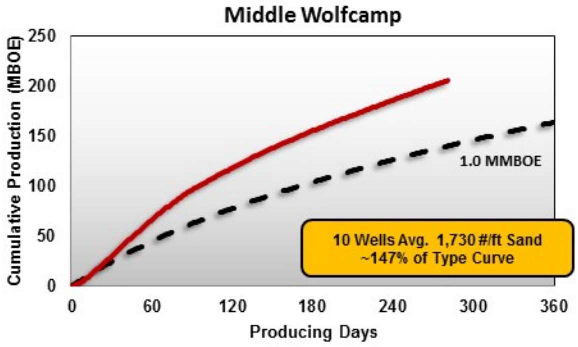


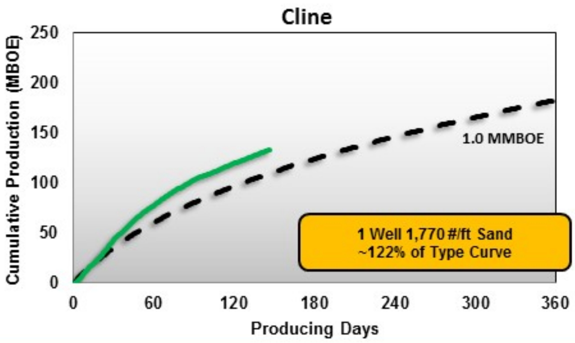
All wells utilizing the Earth Model and optimized completions have performed at an average of ~134% of Oil Type Curve[1]

[1] Average cumulative production data through 7/30/16. 29 Hz wells have utilized both the Earth Model and optimized completions

Earth Model and Optimized Completions Benefits by Horizon



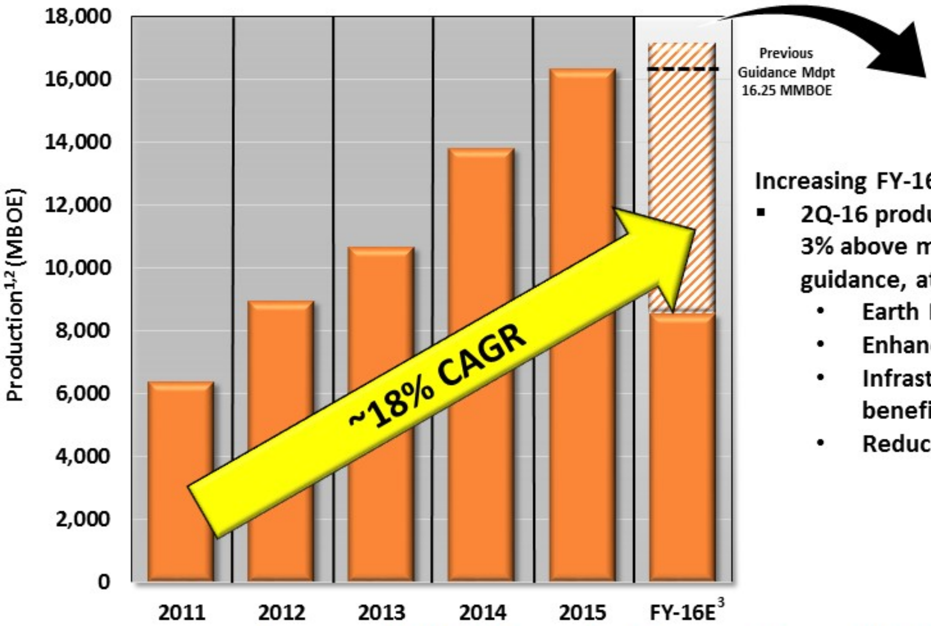




Wells drilled with the Earth Model and optimized completions have resulted in significant outperformance versus the Company's type curves

Note: Average cumulative production data through 7/30/16. Production has been scaled to 10,000' EUR type curves and non-producing days (for shut-ins) have been removed

Raising FY-16 Production Guidance



Increasing FY-16E Production Guidance

- **2Q-16 production of 47.7 MBOE/d, 3% above midpoint of increased guidance, attributable to**
  - **Earth Model utilization**
  - **Enhanced completions**
  - **Infrastructure investment benefits**
  - **Reduced well downtime**

Increased FY-16E production guidance ~5.5% to 17.0 – 17.3 MMBOE

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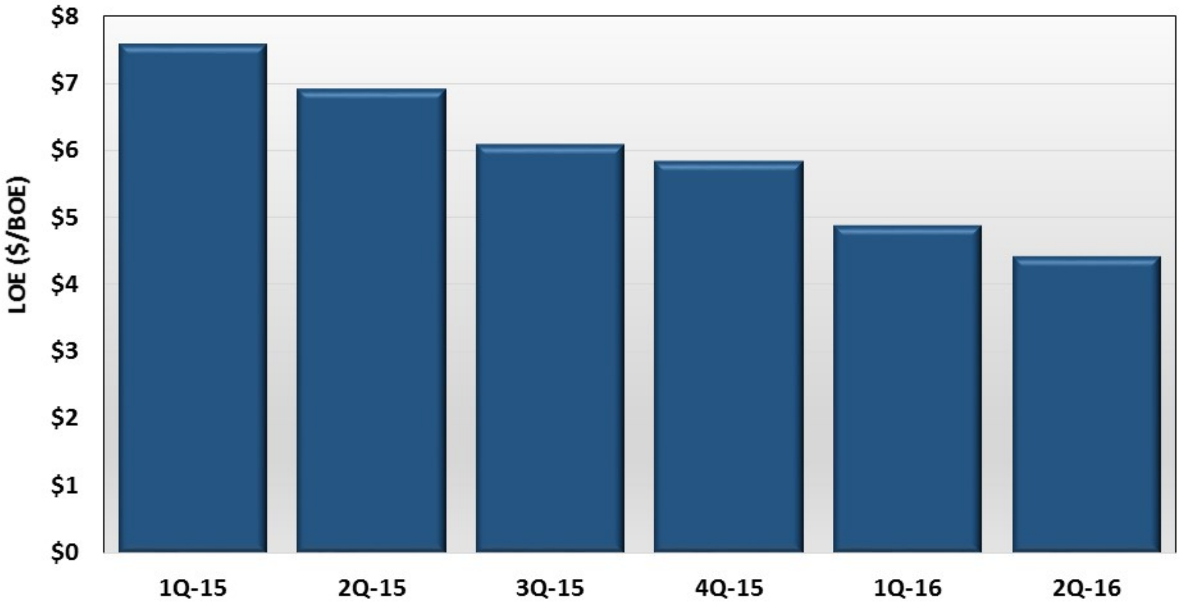
[1] Production numbers prior to 2014 have been converted to 3-stream using an 18% uplift. 2014 results have been converted to 3-stream using actual gas plant economics
[2] 2011 - 2013 adjusted for Granite Wash divestiture, closed August 1, 2013
[3] 2016E based on guidance provided for full-year 2016 in the Company's Press Release dated August 3, 2016

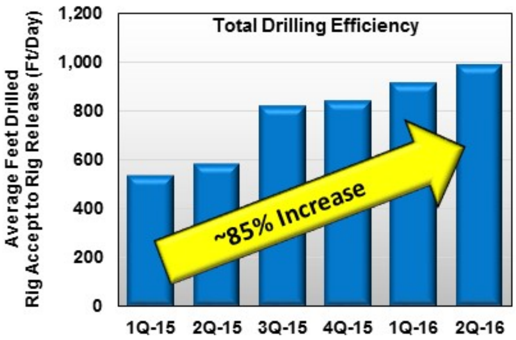
Top-Tier Unit LOE

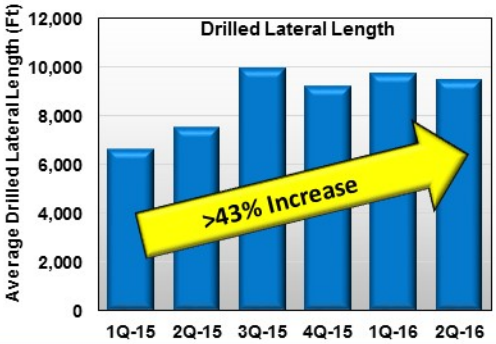


~42% reduction in unit LOE since 1Q-15

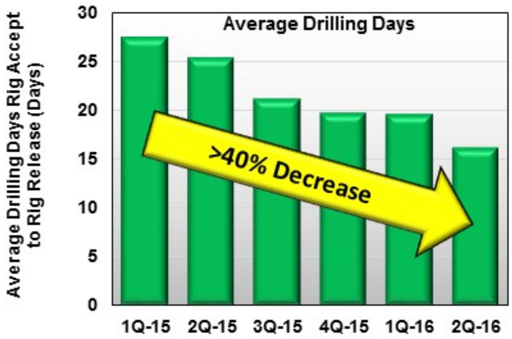
Drilling Efficiencies Yield Ongoing Savings

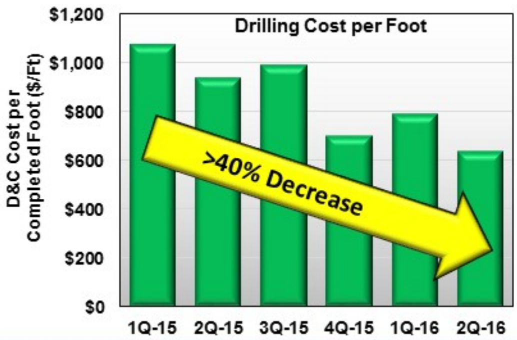
Increased Efficiencies





Lower Costs





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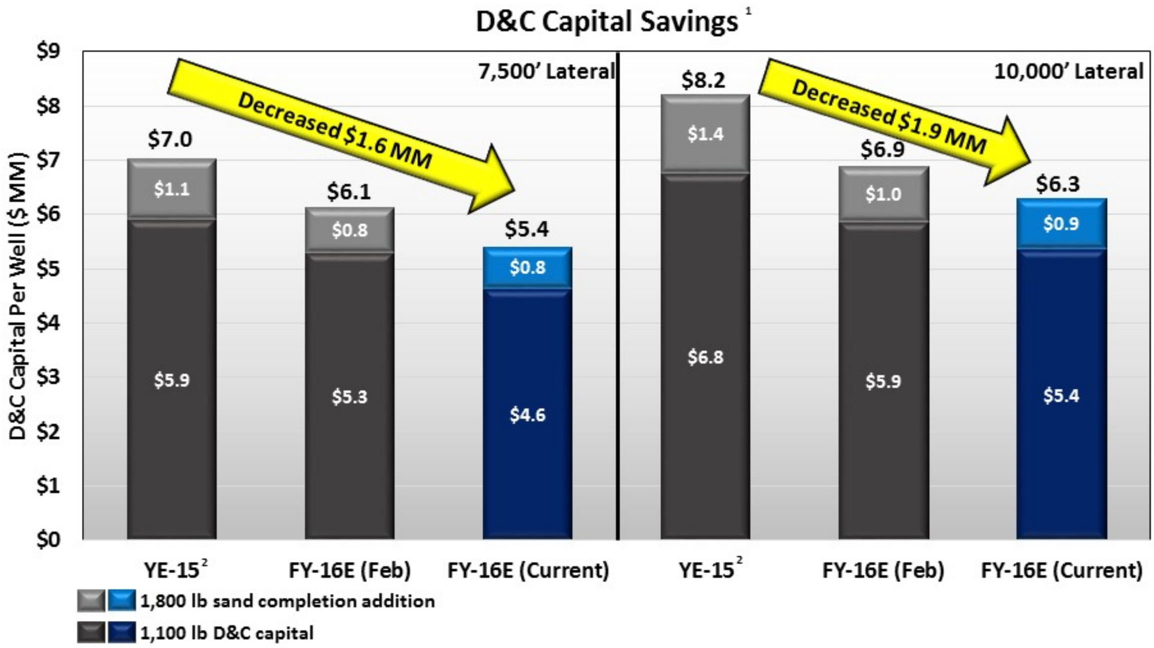
Decreasing D&C Costs



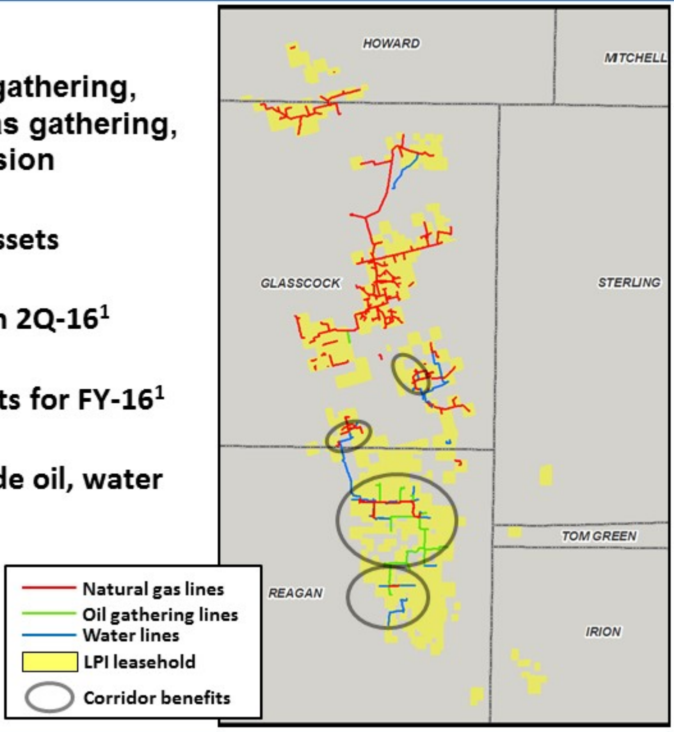
23% average D&C capital savings in 6 months in all zones

[1] Representative of 2-well pad costs
[2] YE-15 well cost estimates for FY-16

Infrastructure Lowers Capital & Operational Costs

- Infrastructure includes crude gathering/transportation, water gathering, distribution & recycle, natural gas gathering, and centralized gas lift compression
- >775 wells served by midstream assets
- >$6.4 MM total realized benefits in 2Q-16[1]
- ~$26.5 MM total estimated benefits for FY-16[1]
- Invested ~$150 MM to date in crude oil, water and natural gas midstream assets

Prior investment in infrastructure providing tangible benefits



[1] Benefits defined as capital savings, LOE savings, price uplift and LMS net operating income

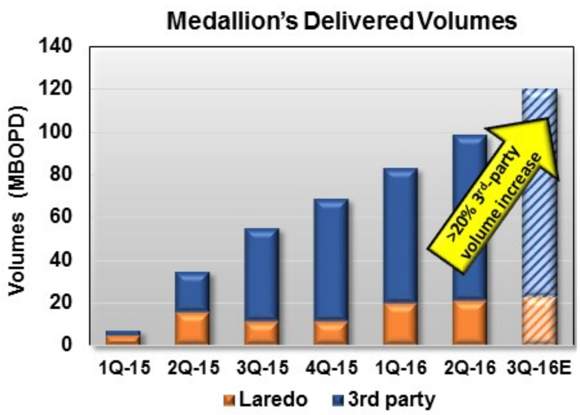
Corridor Financial Benefits

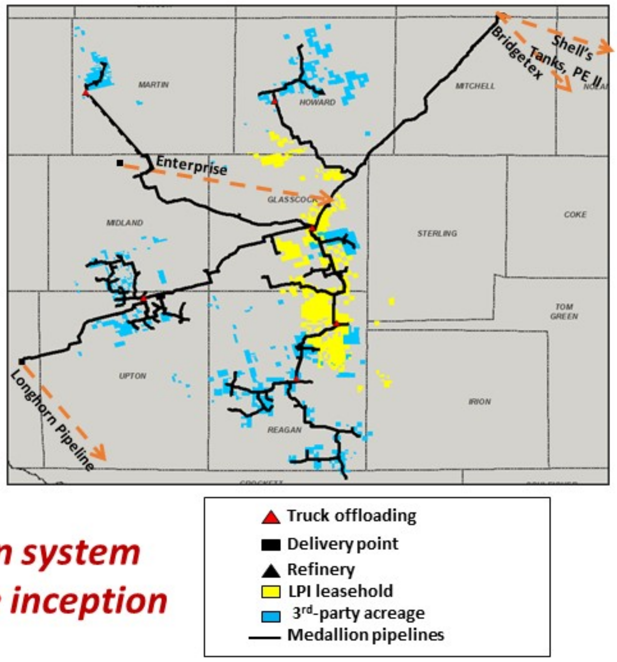
LMS Service	2Q-16 Benefits Actual ($ MM)	2016 Benefits Estimated ($ MM)[1]	LPI Financial Benefits
Crude Gathering	$2.4	$10.5	Increased revenues & 3rd-party income
Centralized Gas Lift	$0.2	$0.8	LOE savings
Frac Water (Recycled vs Fresh)	$0.4	$2.0	Capital savings
Produced Water (Recycled vs Disposed)	$0.6	$2.7	Capital & LOE savings
Produced Water (Gathered vs Trucked)	$2.8	$10.5	Capital & LOE savings
Corridor Benefit	$6.4	$26.5	

~$1.8 million benefit over life of each 10,000' corridor well, with >25% of the benefit received in the first six months[1]

[1] Benefits estimates as of July 28, 2016

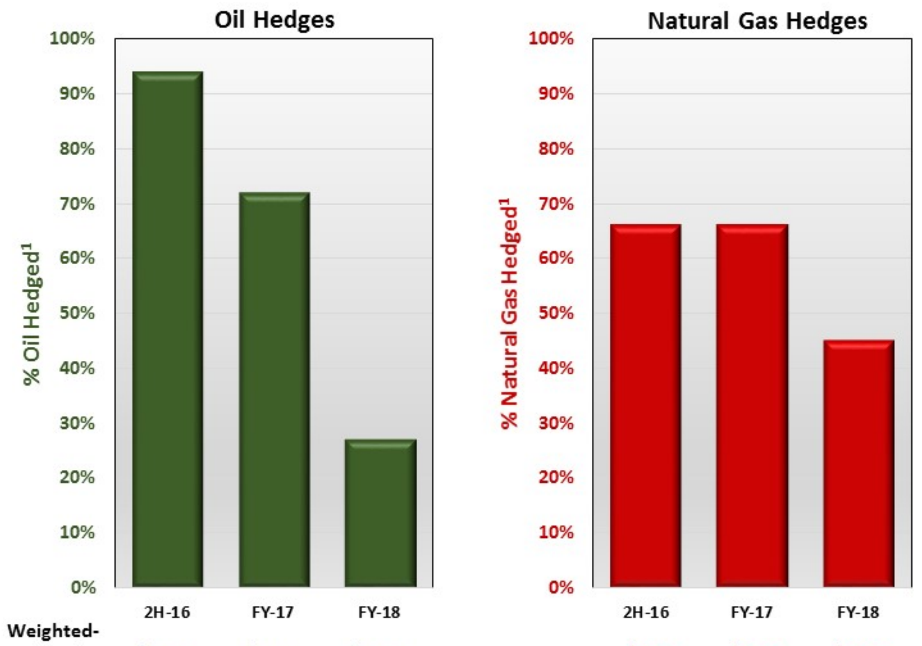
Medallion-Midland Basin Crude Oil System





Throughput on the Medallion system has grown tremendously since inception

Top-Tier, Multi-Year Hedge Position



Weighted-Average Floor Price:	2H-16	FY-17	FY-18
Oil	$67.13	$57.01	$55.98
Natural Gas	$3.00	$2.65	$2.50

Consistent philosophy to protect capital program and debt service while retaining substantial upside

[1] Utilizing flat 2016 production for FY-17 and FY-18 percent hedged

Note: Does not include 2017 NGL hedges of 444,000 Bbl of ethane or 375,000 Bbl of propane

Oil, Natural Gas & Natural Gas Liquids Hedges

OIL[1]	2H-16	2017	2018	Total
Puts:				
Hedged volume (Bbls)	1,098,000	1,049,375	1,049,375	3,196,750
Weighted average price ($/Bbl)	$42.95	$60.00	$60.00	$54.14
Swaps:				
Hedged volume (Bbls)	791,200	2,007,500	1,095,000	3,893,700
Weighted average price ($/Bbl)	$84.82	$51.54	$52.12	$58.46
Collars:				
Hedged volume (Bbls)	1,833,500	2,628,000		4,461,500
Weighted average floor price ($/Bbl)	$73.98	$60.00		$65.74
Weighted average ceiling price ($/Bbl)	$89.62	$97.22		$94.10
Total volume with a floor (Bbls)	3,722,700	5,684,875	2,144,375	11,551,950
Weighted-average floor price ($/Bbl)	$67.13	$57.01	$55.98	$60.08

NATURAL GAS[2]	2H-16	2017	2018	Total
Puts:				
Hedged volume (MMBtu)		8,040,000	8,220,000	16,260,000
Weighted average floor price ($/MMBtu)		$2.50	$2.50	$2.50
Collars:				
Hedged volume (MMBtu)	9,384,000	10,731,000	4,635,500	24,750,500
Weighted average floor price ($/MMBtu)	$3.00	$2.76	$2.50	$2.80
Weighted average ceiling price ($/MMBtu)	$5.60	$3.53	$3.60	$4.33
Total volume with a floor (MMBtu)	9,384,000	18,771,000	12,855,500	41,010,500
Weighted-average floor price ($/MMBtu)	$3.00	$2.65	$2.50	$2.68

NATURAL GAS LIQUIDS[3]	2H-16	2017	2018	Total
Swaps - Ethane:				
Hedged volume (Bbls)		444,000		
Weighted average price ($/Bbl)		$11.24		
Swaps - Propane:				
Hedged volume (Bbls)		375,000		
Weighted average price ($/Bbl)		$22.26		
Total volume with a floor (Bbls)		819,000		

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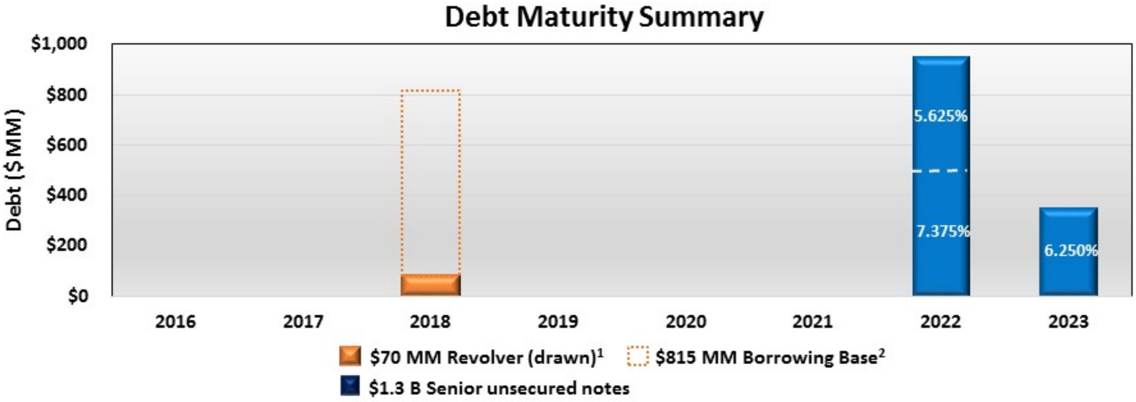
Note: Open positions as of 06/30/16, including hedges placed through 08/03/16
[1] Oil derivatives are settled based on the month's average daily NYMEX price of WTI Light Sweet Crude Oil
[2] Natural gas derivatives are settled based on Inside FERC index price for West Texas Waha for the calculation period
[3] Natural gas liquids derivatives are settled based on the month's daily average of OPIS Mt. Belvieu Purity Ethane and TET Propane

Strong Financial Position

- **~$760 million of liquidity[1]**
- **No term debt due until 2022**
  - **$950 million of notes callable at Laredo's option in 2017**
- **Peer-leading, multi-year hedge position**



[1] As of August 2, 2016
[2] As of May 2016 redetermination; Medallion interest is not pledged to borrowing base

Third-Quarter 2016 Guidance

	3Q-2016
Production (MMBOE)	4.2 - 4.4
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)	~85%
Natural gas liquids (% of WTI)	~25%
Natural gas (% of Henry Hub)	~70%
Operating Costs & Expenses:	
Lease operating expenses ($/BOE)	$4.25 - $4.75
Midstream expenses ($/BOE)	$0.15 - $0.35
Production and ad valorem taxes (% of oil, NGL and natural gas revenue)	8.25%
General and administrative expenses:	
General and administrative - cash ($/BOE)	$3.00 - $3.75
General and administrative - noncash stock-based compensation ($/BOE)	$2.25 - $3.00
Depletion, depreciation and amortization ($/BOE)	$8.00 - $9.00

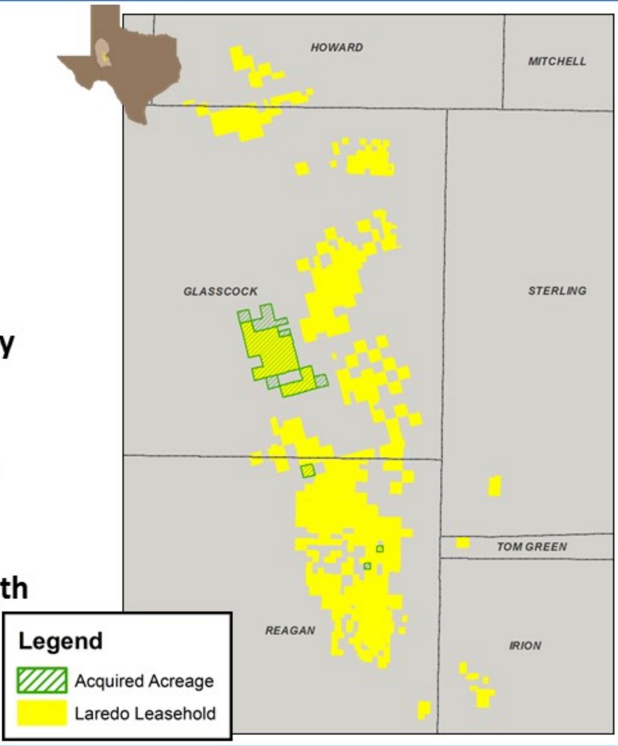
Appendix





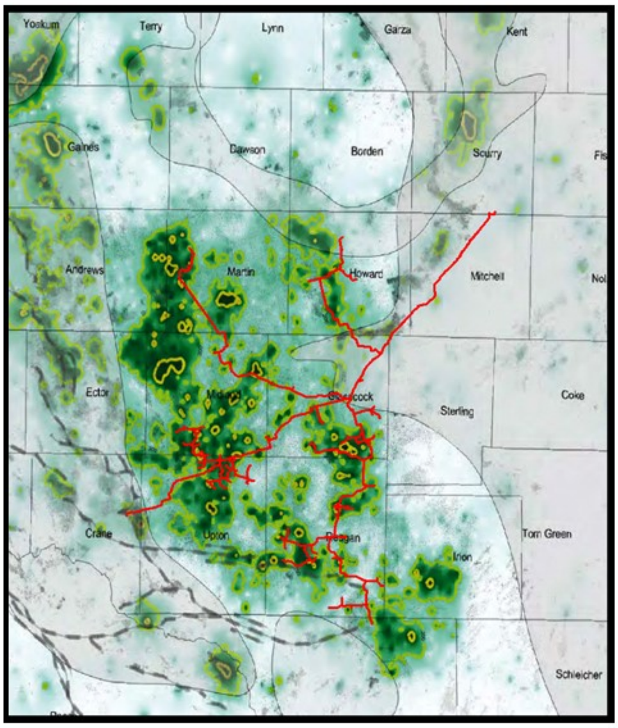

Midland Basin Acreage Acquisition Bolsters Existing Footprint

- **Acquisition overview:**
  - **$125 MM purchase price[1]**
  - **300 BOE/D Laredo-operated production**
  - **~9,200 net acres**
- **Increases working interest in current western Glasscock and Reagan County leasehold**
- **Facilitates value-added new Western Glasscock production corridor**
- **100% of acquired acreage covered with Earth Model**

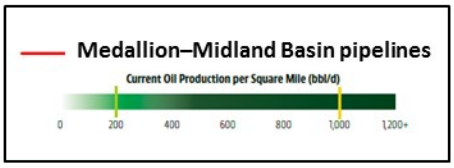


[1] $94.35 MM closed as of 8/2/16 and $30.65 MM expected to close upon the satisfaction of certain preferential purchase rights or consents

Medallion-Midland Basin: The Premier Pipeline in the Permian

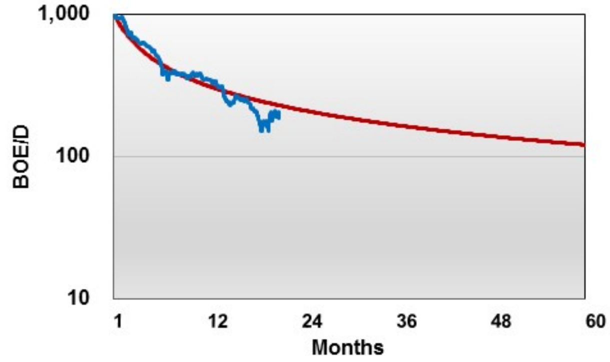


- ~500 miles with >290,000 net acres dedicated to system
- $0.45/Bbl 2Q-16 cash flow margin net to LPI
- YE-16 estimated average exit rate of 140,000 BOPD
- ~2 MM acres either under AMI or supporting firm commitments



Note: Heat map generated by RS Energy Group

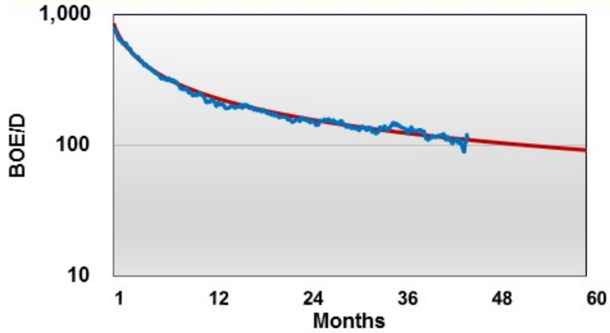
Upper Wolfcamp Type Curves



10,000' Lateral

- EUR: 1,110 MBOE (45% oil)
- 180-day cumulative: 118 MBOE (61% oil)
- 365-day cumulative: 187 MBOE (58% oil)

Normalized production[1]
Type curve



7,500' Lateral

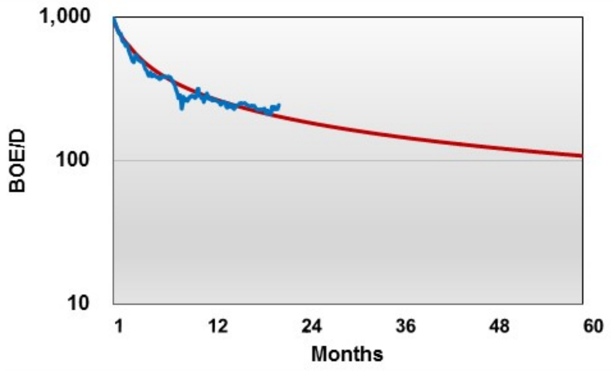
- EUR: 850 MBOE (45% oil)
- 180-day cumulative: 90 MBOE (61% oil)
- 365-day cumulative: 142 MBOE (58% oil)

Normalized production[2]
Type curve

[1] Data includes horizontal wells with lateral lengths >8,500' and 31 stages
[2] Data includes horizontal wells with lateral lengths >6,000' and 24 stages
Note: Production data as of 7/21/16, utilizing 73% residue shrink & 116 Bbl/MMcf yield

LAREDO PETROLEUM

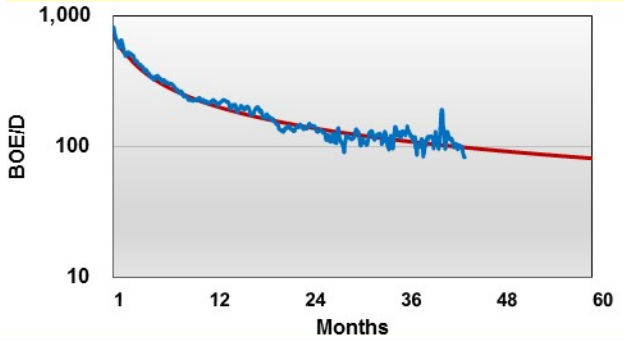
Middle Wolfcamp Type Curves



10,000' Lateral

- EUR: 1,000 MBOE (51% oil)
- 180-day cumulative: 104 MBOE (62% oil)
- 365-day cumulative: 165 MBOE (59% oil)

Normalized production[1]
Type curve



7,500' Lateral

- EUR: 750 MBOE (51% oil)
- 180-day cumulative: 79 MBOE (62% oil)
- 365-day cumulative: 125 MBOE (59% oil)

Normalized production[2]
Type curve

[1] Data includes horizontal wells with lateral lengths >8,500' and 31 stages
[2] Data includes horizontal wells with lateral lengths >6,000' and 24 stages
Note: Production data as of 7/21/16, utilizing 73% residue shrink & 116 Bbl/MMcf yield

2015 & 2016 (YTD) Actuals

		1Q-15	2Q-15	3Q-15	4Q-15	FY-15	1Q-16	2Q-16
Production	**Production (3-Stream)**							
	BOE/D	**47,487**	**46,532**	**44,820**	**40,368**	**44,782**	**46,202**	**47,667**
	% oil	**51%**	**46%**	**45%**	**45%**	**47%**	**48%**	**46%**
Realized Pricing	**3-Stream Prices**							
	Gas ($/Mcf)	$2.14	$1.82	$2.01	$1.76	$1.93	$1.31	$1.31
	NGL ($/Bbl)	$13.34	$12.85	$10.36	$11.06	$11.86	$8.50	$12.24
	Oil ($/Bbl)	$41.73	$50.77	$42.88	$36.97	$43.27	$27.51	$39.37
Unit Cost Metrics	**3-Stream Unit Cost Metrics**							
	Lease Operating ($/BOE)	$7.58	$6.90	$6.09	$5.83	$6.63	$4.88	$4.43
	Midstream ($/BOE)	$0.37	$0.38	$0.26	$0.43	$0.36	$0.14	$0.27
	G&A ($/BOE)	$5.11	$5.48	$5.56	$6.04	$5.53	$4.63	$4.73
	DD&A ($/BOE)	$16.83	$17.03	$16.19	$18.01	$16.99	$9.87	$7.88

2014 Two-Stream to Three-Stream Conversions

		1Q-14	2Q-14	3Q-14	4Q-14	FY-14
Production	**Production (2-Stream)**					
	BOE/D	**27,041**	**28,653**	**32,970**	**39,722**	**32,134**
	% oil	**58%**	**58%**	**59%**	**60%**	**59%**
	Production (3-Stream)					
	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	$82.83
	3-Stream Prices					
	Gas ($/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	$82.83
Unit Cost Metrics	**2-Stream Unit Cost Metrics**					
	Lease Operating ($/BOE)	$8.95	$7.74	$8.30	$8.04	$8.23
	Midstream ($/BOE)	$0.35	$0.59	$0.40	$0.50	$0.46
	G&A ($/BOE)	$11.36	$11.34	$8.93	$5.95	$9.04
	DD&A ($/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	$0.39
	G&A ($/BOE)	$9.50	$9.60	$7.59	$5.10	$7.67
	DD&A ($/BOE)	$17.03	$17.23	$17.91	$18.72	$17.83