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): February 15, 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 February 15, 2017, Laredo Petroleum, Inc. (the "Company") announced its financial and operating results for the quarter and year ended December 31, 2016. Copies of the Company's press release and Presentation (as defined below) are furnished as Exhibit 99.1 and 99.2, respectively, to this Current Report on Form 8-K and are incorporated herein by reference. The Company plans to host a teleconference and webcast on February 16, 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 53302066. A replay of the call will be available through Thursday, February 23, 2017, by dialing 1-855-859-2056, and using conference code 53302066. 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 February 15, 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 February 15, 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 February 15, 2017 announcing financial and operating results.
99.2	Presentation dated February 15, 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: February 15, 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 February 15, 2017 announcing financial and operating results.
99.2	Presentation dated February 15, 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 2016 Fourth-Quarter and Full-Year Financial and Operating Results

Increases Company Type Curves for Upper and Middle Wolfcamp

TULSA, OK - February 15, 2017 - Laredo Petroleum, Inc. (NYSE: LPI) ("Laredo" or the "Company") today announced its 2016 fourth-quarter and full-year results. For the fourth quarter of 2016, the Company reported a net loss attributable to common stockholders of $18.4 million, or $0.08 per diluted share, which includes a loss on derivatives of $43.6 million reflecting matured and new contracts and changes of the market prices in the forward curves of oil, natural gas liquids ("NGL") and natural gas. Adjusted Net Income, a non-GAAP financial measure, for the fourth quarter of 2016 was $38.8 million, or $0.16 per adjusted diluted share. Adjusted EBITDA, a non-GAAP financial measure, for the fourth quarter of 2016, was $134.9 million.

For the year ended December 31, 2016, the Company reported a net loss attributable to common stockholders of $260.7 million, or $1.16 per diluted share, including a non-cash full cost ceiling impairment charge of $161.1 million taken in the first quarter of 2016. Adjusted Net Income for the year ended December 31, 2016 was $112.6 million, or $0.49 per adjusted diluted share, and Adjusted EBITDA was $461.3 million. Please see supplemental financial information at the end of this news release for reconciliation of the non-GAAP financial measures.

2016 Highlights

- Produced a Company record 53,141 barrels of oil equivalent ("BOE") per day in the fourth quarter of 2016, resulting in full-year 2016 production growth of approximately 11% from full-year 2015
- Grew proved developed reserves organically by approximately 40% in 2016 at a proved developed finding and development ("F&D") cost of $5.12 per BOE
- Replaced 322% of production organically with proved developed reserves
- Completed 45 horizontal development wells in 2016 at an average anticipated rate of return on invested capital of greater than 40%
- Reduced unit lease operating expenses ("LOE") to $3.56 per BOE in the fourth quarter of 2016, resulting in a full-year 2016 unit LOE reduction of approximately 37% from full-year 2015
- Recognized approximately $24 million of cash benefits from Laredo Midstream Services, LLC ("LMS") field infrastructure investments through reduced capital and operating costs and increased revenue

- Received approximately $185.6 million of net cash settlements on commodity derivatives that matured during 2016, increasing the average sales price for oil by $20.34 per barrel and for natural gas by $0.47 per thousand cubic feet compared to pre-hedged average sales prices
- Grew annual transported volumes on the Medallion Gathering & Processing, LLC ("Medallion-Midland Basin") system, of which LMS is a 49% owner, by 159% in 2016 to 39.3 million barrels of oil, with a fourth-quarter daily average rate of 129,087 barrels of oil per day ("BOPD")

"From the moment that Laredo leased its first acre in the Midland Basin, the Company's primary strategy has been maximizing Laredo's total value through efficient resource development," stated Randy A. Foutch, Chairman and Chief Executive Officer. "Building a contiguous acreage position, gathering data for the proprietary Earth Model, investing in field infrastructure, developing production corridors and forming a partnership to build the Medallion-Midland Basin system are all part of that goal. In 2016, our strategy provided a substantive, repeatable benefit to the Company."

"Laredo's 2016 development drilling activities achieved anticipated field level returns on invested capital exceeding 40% by leveraging a combination of factors and staying focused on our strategy. The Company's contiguous acreage position enabled the drilling of high-return, long and extended-reach laterals. We utilized the Earth Model to optimize location and landing point selection and completion design, resulting in substantial outperformance versus our historic Upper Wolfcamp, Middle Wolfcamp and Cline type curves. Our field infrastructure and production corridor assets drove capital and operating costs to levels among the lowest in the Midland Basin. These factors enabled Laredo to grow production 11% during the year, organically grow proved developed reserves 41% at a proved developed F&D cost of $5.12 per BOE and fund our drilling program with operating cash flow. Utilizing our Earth Model to optimize location and landing point selection and completion design for wells has continued the strong performance of our drilling program in 2016 and has led the Company to increase its type curves for the Upper and Middle Wolfcamp to 1.3 million BOE."

"We believe 2017 is positioned to be another outstanding year for Laredo. We expect to continue capitalizing on past strategic investments while continually refining our development program. We anticipate drilling even longer laterals, further refining our completion techniques and testing multiple landing points within formations. Our prior infrastructure investments are expected to continue increasing efficiencies and lessen the impact to the Company of rising service costs. The potential to enhance the value of our acreage is still growing. We have multiple years of high-value inventory and our prior investments have positioned the Company to take full advantage of that potential."

Increased Type Curves

Through the application of the Company's proprietary multivariate Earth Model to optimize landing points and the design and completion of horizontal wells, Laredo's development drilling results substantially outperformed the Company's historic type curves. As a result, Laredo has increased the type curves for 10,000-foot horizontal wells in the Upper and Middle Wolfcamp to 1.3 million BOE, from 1.1 million BOE and 1.0 million BOE, respectively. The increases are driven by a 10% uplift in both oil and natural gas volumes to reflect the performance associated with utilization of the multivariate Earth Model. The remaining increase in natural gas volumes reflects historical production data showing gas production outperforming type-curve expectations in later years.

From this point forward, these increased type curves will be the basis for comparing production performance for horizontal wells in the Upper and Middle Wolfcamp within all Company press releases and presentations.

Operational Update

In the fourth quarter of 2016, Laredo produced a Company record 53,141 BOE per day, up 32% from fourth-quarter 2015, resulting in production for full-year 2016 of 18.1 million BOE, an increase of approximately 11% from the 2015 volume. Laredo recognized anticipated field-level returns of greater than 40% for the 2016 development drilling program, driven by increasing average lateral lengths to approximately 10,000 feet, utilization of the multivariate Earth Model to optimize landing points and completions and efficiency-related cost reductions.

The Company completed 10 horizontal development wells in the fourth quarter of 2016 in two multi-well packages. The four-well Taylor package targeting the Middle Wolfcamp was completed early in the quarter utilizing 1,800 pounds of sand per lateral foot. This package is currently outperforming the oil type curve and three-stream type curve of the 1.3 million BOE Middle Wolfcamp type curve by 29% and 35%, respectively, adjusted for lateral length. The remaining six wells were developed as a package targeting the Upper Wolfcamp. These wells were completed late in the quarter and require longer-run data to make appropriate comparisons to Company type curves, although current production trends for the package are encouraging.

Fourth-quarter 2016 production growth was positively impacted by the timing of the seven-well Sugg 171/185 package, which was completed near the end of the third quarter of 2016. These wells targeted the Upper and Middle Wolfcamp and were completed utilizing 2,400 pounds of sand per lateral foot and were produced utilizing a managed drawdown protocol. The results of these larger completions are very encouraging as the package is currently outperforming the oil type curve and three-stream type curve of the 1.3 million BOE Upper and Middle Wolfcamp type curves by 41% and 24%, respectively, adjusted for lateral length. Production trends indicate the type curve outperformance may still be increasing and the Company will continue to monitor the results to determine the long-term, incremental uplift from both the larger completion and the utilization of a managed drawdown protocol.

Four of the wells in the Sugg 171/185 package were extended-reach laterals, with drilled lateral lengths averaging approximately 13,400 feet. The wells averaged 18 days to drill, from rig accept to rig release, the best of which was drilled in a Company record 16 days. The superior economics of drilling long laterals combined with the Company's success in executing extended-reach laterals is expected to continue to drive higher returns as the average lateral length increases in Laredo's overall development plan. The Company has identified more than 2,000 locations that support lateral lengths of 10,000 feet or longer on its contiguous acreage base and expects the average drilled lateral length of its 2017 drilling program to be approximately 10,000 feet.

In 2016, Laredo completed 44 of its 45 horizontal development wells as multi-well packages. Through extensive data collection and analysis with the multivariate Earth Model, the Company has continued to optimize resource development to minimize the impact of pressure depletion on future drilling locations. Additionally, multi-well packages enable highly efficient batch drilling and completions operations which reduce well costs and minimize non-productive time. The Company's strategy of building production corridors and other field infrastructure enables the cost-efficient drilling and completion of multi-well packages. The completion of a five-well package requires approximately 3 million barrels of frac water in a two-week period. The Company's infrastructure handles the supply and takeaway of flowback and produced water for the multi-well packages. This facilitates execution logistics and reduces the risks and costs associated with the completion operations, all of which could diminish returns.

Lease operating expenses continue to be driven lower as costs benefit from the Company's prior investments in water handling infrastructure and centralized gas lift, as well as the increased activity along Laredo's production corridors. These infrastructure-related savings, which Laredo retains permanently, reduced fourth-quarter unit LOE by approximately $0.51 per BOE. As a result, unit LOE decreased to $3.56 per BOE in the fourth quarter of 2016, down approximately 39% from the 2015 rate of $5.83 per BOE and down more than 7% sequentially from the third-quarter 2016 rate.

2017 Development Program

The Company expects to complete 12 horizontal development wells in the first quarter of 2017. The wells are being drilled as a nine-well package and a package of three wells, with 11 wells targeting the Upper and Middle Wolfcamp and one targeting the Cline. The completion timing of the nine-well package is expected to push the commencement of production on both packages to the later part of the quarter. This is expected to result in first-quarter completions having minimal impact on first quarter production but contributing meaningfully to production growth in the second quarter of 2017.

Throughout 2017, Laredo expects to apply results from the completions optimization and multivariate Earth Model workflows to test several concepts that could, if successful, have a substantial positive impact on stockholder value. The Upper and Middle Wolfcamp have a combined average thickness greater than 1,000 feet across the Company's acreage with proven horizontal productivity across at least four distinct landing points within these two targets. Well packages designed to co-develop several landing points within the same target are planned in 2017, with the goal of adding additional high-value locations.

Laredo Midstream Services Update

Laredo's midstream strategy of investing in field infrastructure continues to produce growing operating and financial benefits for the Company. LMS' oil and gas gathering, water system and centralized compression assets generated a combined cash benefit and capital and operating cost savings of approximately $5.5 million to the Company in the fourth quarter of 2016.

LMS' water system assets are a key component of the Company's field infrastructure and production corridor system. Water assets consist of approximately 78 miles of pipeline, a recycling plant capable of processing 30,000 barrels of water per day ("BWPD") and linked water storage assets with a storage capacity of more than 5 million barrels of water. In the fourth quarter of 2016, LMS' water system assets transported approximately 65% of the Company's produced water on pipe, of which 56% was recycled by Laredo, reducing the need for fresh water.

The Company's strategy of securing firm takeaway capacity led to its 49% ownership in the Medallion-Midland Basin system. Laredo's investment in the system generated income of $3.1 million and Adjusted EBITDA, a non-GAAP financial measure, of $6.4 million in the fourth quarter of 2016 and income of $9.4 million and Adjusted EBITDA of $20.4 million for full-year 2016, net to the Company's 49% interest in the system. Please see supplemental financial information at the end of this news release for reconciliation of the non-GAAP financial measures.

The Company's investment in the Medallion-Midland Basin system continues to add value as the system's throughput has grown rapidly. Upon completion of current projects, the system will consist of more than 650 miles of pipeline, of which more than 500 miles are six-inch pipe or larger. The system accesses many of the most productive areas of the Midland Basin, can deliver more than 500,000 BOPD into four delivery locations and has more than 520,000 net acres dedicated to the system or supporting firm transportation commitments. Approximately 80% of transported volumes are from third-party producers, up from approximately 35% at the inception of the system. In the fourth quarter of 2016, volumes grew to an average of approximately 129,000 BOPD, an increase of approximately 87% from the fourth quarter of 2015. Average daily volumes exited 2016 at approximately 133,000 BOPD and are expected to grow by greater than 75% by the end of 2017.

"The Medallion-Midland Basin system was built to provide flexibility to transport the Company's oil to delivery locations outside of the Midland market, enabling Laredo to access long-haul pipelines to the Gulf Coast and creates optionality for the best pricing," commented Mr. Foutch. "As other operators recognized the value of the system, Medallion expanded and the value of Laredo's 49% interest has grown dramatically. The original rationale for building the pipeline, to provide operational flexibility, has been realized through the Company's contract for 30,000 BOPD of firm capacity on the system. The investment also provides financial flexibility for Laredo as the EBITDA and value of the investment continue to grow."

Reserves and Locations

Laredo's 2016 development drilling plan, in conjunction with upward performance revisions and operating cost reductions that increased the economic life of producing wells added 58 million BOE of proved developed reserves, replacing 322% of production. The exceptional well performance and operational efficiencies that reduced drilling and completion costs resulted in a proved developed F&D cost of $5.12 per BOE.

Total proved reserves at year-end 2016 increased 41 million BOE to 167 million BOE, growing 33% from year-end 2015. Proved developed reserves increased 41% to 141 million BOE and represent 84% of total proved reserves, an increase from 80% at year-end 2015. Proved undeveloped ("PUD") reserves were essentially unchanged as Laredo, beginning in 2016, purposely reduced PUD bookings. This strategy enables the Company to develop its acreage in the most efficient manner possible and provides it the most flexibility to enhance shareholder value at prevailing conditions. The Company has identified more than 3,500 locations capable of generating at least a 10% field level rate of return in the current commodity price and service cost environment. Included in this count is approximately a decade of inventory, at the Company's current rig cadence, of horizontal wells capable of at least a 40% rate of return at current commodity prices and service costs.

The standardized measure of the Company's proved reserves at year-end 2016 was $978.5 million, an increase of 18% from the standardized measure at year-end 2015 of $830.7 million. The volume and value of the Company's proved reserves increased despite an 18% percent decrease in the price of oil and a 6% decrease in the price of natural gas and NGL used to calculate the value of the reserves.

2016 Capital Program

Laredo outperformed its anticipated 2016 production while spending significantly less than planned. The Company executed its 2016 capital program for $334 million, 20% below its $420 million budget. The trend of higher production with lower capital expenditures throughout 2016 resulted in steadily increasing quarterly cash flow from operations, which fully funded the full-year capital program, excluding acquisitions and investments in the Medallion-Midland Basin system.

During the fourth quarter of 2016, Laredo invested approximately $78.2 million in exploration and development activities, approximately $12.3 million in bolt-on acquisitions and approximately $12.6 million in infrastructure held by LMS and the Medallion-Midland Basin system. For full-year 2016, Laredo invested approximately $317.2 million in exploration and development activities, approximately $148.9 million in bolt-on acquisitions and approximately $45.2 million in infrastructure held by LMS and the Medallion-Midland Basin system.

Liquidity

At December 31, 2016, the Company had cash and cash equivalents of approximately $33 million and undrawn capacity under the senior secured credit facility of $745 million. At February 14, 2017, the Company had cash and cash equivalents of approximately $24 million and undrawn capacity under the senior secured credit facility of $800 million, resulting in total liquidity of approximately $824 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 December 31, 2016, the Company had hedges in place for 2017 for 6,852,875 barrels of oil at a weighted-average floor price of $55.82 per barrel, representing approximately 70% of anticipated oil production in 2017. Approximately 80% of total anticipated oil production in 2017 retains significant upside to an increase in the price of oil with those volumes either having a weighted-average ceiling price of $86.00 per barrel or no ceiling at all. Additionally, the Company had hedges in place for 2017 for 27,056,500 million British thermal units ("MMBtu") of natural gas at a WAHA weighted-average floor price of $2.75 per MMBtu, 444,000 barrels of ethane at $11.24 per barrel and 375,000 barrels of propane at $22.26 per barrel.

Guidance

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

	1Q-2017	2Q-2017
Production (MBOE/d)	52 - 54	55 - 58
Product % of total production:		
Crude oil	44% - 46%	45% - 47%
Natural gas liquids	27% - 28%	*
Natural gas	27% - 28%	*
Price Realizations (pre-hedge):		
Crude oil (% of WTI)	~90%	*
Natural gas liquids (% of WTI)	~32%	*
Natural gas (% of Henry Hub)	~72%	*
Operating Costs & Expenses:		
Lease operating expenses ($/BOE)	$3.50 - $4.00	*
Midstream expenses ($/BOE)	$0.20 - $0.30	*
Production and ad valorem taxes (% of oil, NGL and natural gas revenue)	6.75%	*
General and administrative expenses:		
Cash ($/BOE)	$3.35 - $3.85	*
Non-cash stock-based compensation ($/BOE)	$2.00 - $2.25	*
Depletion, depreciation and amortization ($/BOE)	$7.50 - $8.00	*

** Not provided*

Fourth-Quarter and Full-Year 2016 Earnings Conference Call

Laredo will host a conference call on Thursday, February 16, 2017 at 7:30 a.m. CT (8:30 a.m. ET) to discuss its fourth-quarter and full-year 2016 financial and operating results and management's outlook. Individuals who would like to participate on the call should dial 877.930.8286 (international dial-in 253.336.8309), using conference code 53302066 or listen to the call via the Company's website at www.laredopetro.com, under the tab for "Investor Relations." A telephonic replay will be available approximately two hours after the call on February 16, 2017 through Thursday, February 23, 2017. Participants may access this replay by dialing 855.859.2056, using conference code 53302066.

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 in 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, 2015, and those set forth from time to time in other filings with the Securities Exchange Commission ("SEC") including, but not limited to, its Annual Report on Form 10-K for the year ended December 31, 2016, to be filed with the 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, and are not intended to represent the fair market value of the Company's proved reserves. 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 December 31, 2016	Three months ended December 31, 2015	Year ended December 31, 2016	Year ended December 31, 2015
	(unaudited)		(unaudited)	
Revenues:				
Oil, NGL and natural gas sales	$ 136,012	$ 83,455	$ 426,485	$ 431,734
Midstream service revenues	2,421	1,640	8,342	6,548
Sales of purchased oil	45,881	38,180	162,551	168,358
Total revenues	184,314	123,275	597,378	606,640
Costs and expenses:				
Lease operating expenses	17,407	21,643	75,327	108,341
Production and ad valorem taxes	7,103	6,411	28,586	32,892
Midstream service expenses	1,251	1,583	4,077	5,846
Minimum volume commitments	627	—	2,209	5,235
Costs of purchased oil	48,346	41,760	169,536	174,338
General and administrative	25,698	22,449	91,756	90,425
Restructuring expenses	—	—	—	6,042
Accretion of asset retirement obligations	896	652	3,483	2,423
Depletion, depreciation and amortization	37,526	66,893	148,339	277,724
Impairment expense	—	977,561	162,027	2,374,888
Total costs and expenses	138,854	1,138,952	685,340	3,078,154
Operating income (loss)	45,460	(1,015,677)	(87,962)	(2,471,514)
Non-operating income (expense):				
Gain (loss) on derivatives, net	(43,642)	72,455	(87,425)	214,291
Income from equity method investee	3,144	2,214	9,403	6,799
Interest expense	(23,004)	(23,487)	(93,298)	(103,219)
Loss on early redemption of debt	—	—	—	(31,537)
Other, net	(379)	(152)	(1,457)	(1,701)
Non-operating income (expense), net	(63,881)	51,030	(172,777)	84,633
Loss before income taxes	(18,421)	(964,647)	(260,739)	(2,386,881)
Income tax benefit:				
Deferred	—	—	—	176,945
Total income tax benefit	—	—	—	176,945
Net loss	$ (18,421)	$ (964,647)	$ (260,739)	$ (2,209,936)
Net loss per common share:				
Basic	$ (0.08)	$ (4.57)	$ (1.16)	$ (11.10)
Diluted	$ (0.08)	$ (4.57)	$ (1.16)	$ (11.10)
Weighted-average common shares outstanding:				
Basic	238,047	211,255	225,512	199,158
Diluted	238,047	211,255	225,512	199,158

Laredo Petroleum, Inc.
Condensed consolidated balance sheets

(in thousands)	December 31, 2016	December 31, 2015
Assets:	(unaudited)	(unaudited)
Current assets	$ 154,777	$ 332,232
Property and equipment, net	1,366,867	1,200,255
Other noncurrent assets	260,702	280,800
Total assets	$ 1,782,346	$ 1,813,287
Liabilities and stockholders' equity:		
Current liabilities	$ 187,945	$ 216,815
Long-term debt, net	1,353,909	1,416,226
Other noncurrent liabilities	59,919	48,799
Stockholders' equity	180,573	131,447
Total liabilities and stockholders' equity	$ 1,782,346	$ 1,813,287

Laredo Petroleum, Inc.
Condensed consolidated statements of cash flows

(in thousands)	Three months ended December 31, 2016	Three months ended December 31, 2015	Year ended December 31, 2016	Year ended December 31, 2015
	(unaudited)		(unaudited)	
Cash flows from operating activities:				
Net loss	$ (18,421)	$ (964,647)	$ (260,739)	$ (2,209,936)
Adjustments to reconcile net loss to net cash provided by operating activities:				
Deferred income tax benefit	—	—	—	(176,945)
Depletion, depreciation and amortization	37,526	66,893	148,339	277,724
Impairment expense	—	977,561	162,027	2,374,888
Loss on early redemption of debt	—	—	—	31,537
Non-cash stock-based compensation, net of amounts capitalized	9,667	6,576	29,229	24,509
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	43,642	(72,455)	87,425	(214,291)
Cash settlements received for matured derivatives, net	37,655	79,402	195,281	255,281
Cash settlements received for early terminations of derivatives, net	—	—	80,000	—
Cash premiums paid for derivatives	(2,697)	(1,249)	(89,669)	(5,167)
Amortization of debt issuance costs	1,048	1,115	4,279	4,727
Other, net	(1,473)	(1,159)	(10,127)	(4,525)
Cash flows from operations before changes in working capital	106,947	92,037	346,045	357,802
Changes in working capital	4,016	(2,839)	10,669	(46,055)
Changes in other noncurrent liabilities and fair value of performance unit awards	(122)	1,245	(419)	4,200
Net cash provided by operating activities	110,841	90,443	356,295	315,947
Cash flows from investing activities:				
Deposit received for sale of oil and natural gas properties	3,000	—	3,000	—
Capital expenditures:				
Acquisitions of oil and natural gas properties	(9,060)	—	(124,660)	—
Oil and natural gas properties	(83,944)	(97,666)	(360,679)	(588,017)
Midstream service assets	(1,009)	(222)	(5,240)	(35,459)
Other fixed assets	(6,629)	(586)	(7,611)	(9,125)
Investment in equity method investee	(10,897)	(36,844)	(69,609)	(99,855)
Proceeds from dispositions of capital assets, net of selling costs	32	(312)	397	64,949
Net cash used in investing activities	(108,507)	(135,630)	(564,402)	(667,507)
Cash flows from financing activities:				
Borrowings on Senior Secured Credit Facility	25,000	—	239,682	310,000
Payments on Senior Secured Credit Facility	(25,000)	—	(304,682)	(475,000)
Issuance of March 2023 Notes	—	—	—	350,000
Redemption of January 2019 Notes	—	—	—	(576,200)
Proceeds from issuance of common stock, net of offering costs	—	—	276,052	754,163
Other, net	(22)	(62)	(1,427)	(9,570)
Net cash (used in) provided by financing activities	(22)	(62)	209,625	353,393
Net increase (decrease) in cash and cash equivalents	2,312	(45,249)	1,518	1,833
Cash and cash equivalents, beginning of period	30,360	76,403	31,154	29,321
Cash and cash equivalents, end of period	$ 32,672	$ 31,154	$ 32,672	$ 31,154

Laredo Petroleum, Inc.
Selected operating data

	Three months ended December 31,		Year ended December 31,	
	2016	2015	2016	2015
	(unaudited)		(unaudited)	
Sales volumes:				
Oil (MBbl)	2,274	1,656	8,442	7,610
NGL (MBbl)	1,293	1,033	4,784	4,267
Natural gas (MMcf)	7,935	6,153	29,535	26,816
Oil equivalents (MBOE)(1)(2)	4,889	3,714	18,149	16,346
Average daily sales volumes (BOE/D)(2)	53,141	40,368	49,586	44,782
% Oil(2)	46%	45%	47%	47%
Average sales prices:				
Oil, realized ($/Bbl)(3)	$ 43.98	$ 36.97	$ 37.73	$ 43.27
NGL, realized ($/Bbl)(3)	14.79	11.06	11.91	11.86
Natural gas, realized ($/Mcf)(3)	2.13	1.76	1.73	1.93
Average price, realized ($/BOE)(3)	27.82	22.47	23.50	26.41
Oil, hedged ($/Bbl)(4)	58.92	80.61	58.07	74.41
NGL, hedged ($/Bbl)(4)	14.79	11.06	11.91	11.86
Natural gas, hedged ($/Mcf)(4)	2.26	2.72	2.20	2.42
Average price, hedged ($/BOE)(4)	34.97	43.51	33.73	41.71
Average costs per BOE sold:				
Lease operating expenses	$ 3.56	$ 5.83	$ 4.15	$ 6.63
Production and ad valorem taxes	1.45	1.73	1.58	2.01
Midstream service expenses	0.26	0.43	0.22	0.36
General and administrative:				
Cash	3.28	4.27	3.45	4.03
Non-cash stock-based compensation, net of amounts capitalized	1.98	1.77	1.61	1.50
Depletion, depreciation and amortization	7.68	18.01	8.17	16.99
Total	$ 18.21	$ 32.04	$ 19.18	$ 31.52

(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-effects 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.

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 December 31,		Year ended December 31,	
(in thousands)	**2016**	**2015**	**2016**	**2015**
	(unaudited)		(unaudited)	
Property acquisition costs:				
Evaluated[1]	$ —	$ —	$ 5,905	$ —
Unevaluated	9,123	—	119,923	—
Exploration costs	7,583	4,540	41,333	20,697
Development costs[2]	73,839	118,936	298,942	500,577
Total costs incurred	$ 90,545	$ 123,476	$ 466,103	$ 521,274

(1) Evaluated property acquisition costs include $1.1 million in asset retirement obligations for the year ended December 31, 2016.

(2) Development costs include $2.0 million and $12.1 million in asset retirement obligations for the three months ended December 31, 2016 and 2015, respectively, and $2.5 million and $13.4 million for the years ended December 31, 2016 and 2015, respectively.

Non-GAAP financial measures

The non-GAAP financial measures of Adjusted Net Income, Adjusted EBITDA, PV-10 and proved developed Finding & Development Cost, 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, Adjusted EBITDA, PV-10 or proved developed Finding and Development Cost should not be considered in isolation or as a substitute for GAAP measures, such as net income or loss, operating income or loss, standardized measure of discounted future net cash flows 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, cash 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.

Including a higher weighted-average common 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, our net income (loss) (GAAP) per common share calculation utilizes the same denominator for both basic and diluted net income (loss) per common share. However, our calculation of Adjusted Net Income (non-GAAP) results in income for all 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 periods ending December 31, 2016 and 2015, we present a line item that calculates Adjusted Net Income per Adjusted diluted common share. Accordingly, 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):

(in thousands, except for per share data, unaudited)	Three months ended December 31, 2016	Three months ended December 31, 2015	Year ended December 31, 2016	Year ended December 31, 2015
Net loss	$ (18,421)	$ (964,647)	$ (260,739)	$ (2,209,936)
Plus:				
Deferred income tax benefit	—	—	—	(176,945)
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	43,642	(72,455)	87,425	(214,291)
Cash settlements received for matured derivatives, net	37,655	79,402	195,281	255,281
Cash settlements received for early terminations of derivatives, net	—	—	80,000	—
Cash premiums paid for derivatives	(2,697)	(1,249)	(89,669)	(5,167)
Impairment expense	—	977,561	162,027	2,374,888
Restructuring expenses	—	—	—	6,042
Loss on early redemption of debt	—	—	—	31,537
Buyout of minimum volume commitment	—	—	—	3,014
Loss on disposal of assets, net	411	190	790	2,127
Write-off of debt issuance costs	—	—	842	—
Bad debt expense	—	148	—	255
Adjusted net income before adjusted income tax expense	60,590	18,950	175,957	66,805
Adjusted income tax expense[(1)]	(21,812)	(6,822)	(63,345)	(24,050)
Adjusted Net Income	$ 38,778	$ 12,128	$ 112,612	$ 42,755
Net loss per common share:				
Basic	$ (0.08)	$ (4.57)	$ (1.16)	$ (11.10)
Diluted	$ (0.08)	$ (4.57)	$ (1.16)	$ (11.10)
Adjusted Net Income per common share:				
Basic	$ 0.16	$ 0.06	$ 0.50	$ 0.21
Adjusted diluted	$ 0.16	$ 0.06	$ 0.49	$ 0.21
Weighted-average common shares outstanding:				
Basic	238,047	211,255	225,512	199,158
Diluted	238,047	211,255	225,512	199,158
Adjusted diluted	243,507	214,359	228,676	202,216

(1) Adjusted income tax expense is calculated by applying a tax rate of 36%.

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, accretion of asset retirement obligations, restructuring expenses, gains or losses on derivatives, cash settlements received for matured derivatives, cash settlements on early terminated and modified derivatives, cash 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, buyout of minimum volume commitment, income or loss from equity method investee and proportionate Adjusted EDITDA of equity method investee. 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.

For 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 periods' Adjusted EBITDA has been modified for comparability.

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

	Three months ended December 31,		Year ended December 31,	
(in thousands, unaudited)	**2016**	**2015**	**2016**	**2015**
Net loss	$ (18,421)	$ (964,647)	$ (260,739)	$ (2,209,936)
Plus:				
Deferred income tax benefit	—	—	—	(176,945)
Depletion, depreciation and amortization	37,526	66,893	148,339	277,724
Bad debt expense	—	148	—	255
Impairment expense	—	977,561	162,027	2,374,888
Non-cash stock-based compensation, net of amounts capitalized	9,667	6,576	29,229	24,509
Accretion of asset retirement obligations	896	652	3,483	2,423
Restructuring expenses	—	—	—	6,042
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	43,642	(72,455)	87,425	(214,291)
Cash settlements received for matured derivatives, net	37,655	79,402	195,281	255,281
Cash settlements received for early terminations of derivatives, net	—	—	80,000	—
Cash premiums paid for derivatives	(2,697)	(1,249)	(89,669)	(5,167)
Interest expense	23,004	23,487	93,298	103,219
Write-off of debt issuance costs	—	—	842	—
Loss on disposal of assets, net	411	190	790	2,127
Loss on early redemption of debt	—	—	—	31,537
Buyout of minimum volume commitment	—	—	—	3,014
Income from equity method investee	(3,144)	(2,214)	(9,403)	(6,799)
Proportionate Adjusted EBITDA of equity method investee[(1)]	6,386	3,609	20,367	9,383
Adjusted EBITDA	$ 134,925	$ 117,953	$ 461,270	$ 477,264

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

	Three months ended December 31,		Year ended December 31,	
(in thousands, unaudited)	**2016**	**2015**	**2016**	**2015**
Income from equity method investee	$ 3,144	$ 2,214	$ 9,403	$ 6,799
Adjusted for proportionate share of:				
Depreciation and amortization	3,242	1,395	10,964	4,061
Buyout of minimum volume commitment	—	—	—	(1,477)
Proportionate Adjusted EBITDA of equity method investee	$ 6,386	$ 3,609	$ 20,367	$ 9,383

PV-10 (Unaudited)

PV-10 is derived from the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. PV-10 is a computation of the standardized measure of discounted future net cash flows on a pre-tax basis. PV-10 is equal to the standardized measure of discounted future net cash flows at the applicable date, before deducting future income taxes, discounted at 10 percent. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our proved oil, NGL and natural gas assets. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our proved reserves to other companies. We use this measure when assessing the potential return on investment related to our proved oil, NGL and natural gas assets. However, PV-10 is not a substitute for the standardized measure of discounted future net cash flows. Our PV-10 measure and the standardized measure of discounted future net cash flows do not purport to present the fair value of our oil, NGL and natural gas reserves of the property.

(in thousands, unaudited)	**December 31, 2016**
Pre-tax PV-10	$ 978,494
Present value of future income taxes discounted at 10%	—
Standardized measure of discounted future net cash flows	$ 978,494

Proved Developed Finding and Development Cost (Unaudited)

Proved developed finding and development ("F&D") cost is calculated by dividing (x) development costs for the period, by (y) proved developed reserve additions for the period, defined as the change in proved developed reserves, less purchased reserves, plus sold reserves and plus sales volumes during the period. The method we use to calculate our proved developed F&D cost may differ significantly from methods used by other companies to compute similar measures. As a result, our proved developed F&D cost may not be comparable to similar measures provided by other companies. We believe that providing the measure of proved development F&D cost is useful in evaluating the cost, on a per BOE basis, to added proved developed reserves.

However, this measure is provided in addition to, and not as an alternative for, and should be read in conjunction with, the information contained in our financial statements prepared in accordance with GAAP. Due to various factors, including timing differences in the addition of proved reserves and the related costs to develop those reserves, proved developed F&D cost do not necessarily reflect precisely the costs associated with particular proved reserves. As a result of various factors that could materially affect the timing and amounts of future increases in proved reserves and the timing and amounts of future costs, we cannot assure you that our future proved developed F&D cost will not differ materially from those presented.

($ in thousands, except per BOE amount, reserves and sales volumes in MBOE, unaudited)	**F&D**
Development costs (x)	$ 298,942
Proved developed reserves:	
As of December 31, 2016	141,155
As of December 31, 2015	(100,395)
Proved developed reserve additions	40,760
Less purchased proved developed reserves during 2016	(529)
Plus 2016 sales volumes	18,149
Drill bit proved developed reserve additions (y)	58,380
F&D cost per BOE	$ 5.12

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EXHIBIT 99.2

Forward-Looking / Cautionary Statements

This presentation, including any oral statements made regarding the contents of this presentation, contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical fact, included in this presentation that address activities, events or developments that Laredo Petroleum, Inc. (together with its subsidiaries, the "Company", "Laredo" or "LPI") assumes, plans, expects, believes or anticipates will or may occur in the future are forward-looking statements. The words "believe," "expect," "may," "estimates," "will," "anticipate," "plan," "project," "intend," "indicator," "foresee," "forecast," "guidance," "should," "would," "could," "goal," "target," "suggest" or other similar expressions are intended to identify forward-looking statements, which are generally not historical in nature and are not guarantees of future performance. However, the absence of these words does not mean that the statements are not forward-looking. Without limiting the generality of the foregoing, forward-looking statements contained in this presentation specifically include the expectations of plans, strategies, objectives and anticipated financial and operating results of the Company, including the Company's drilling program, production, hedging activities, capital expenditure levels and other guidance included in this presentation. These statements are based on certain assumptions made by the Company based on management's expectations and perception of historical trends, current conditions, anticipated future developments and rate of return and other factors believed to be appropriate. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the Company, which may cause actual results to differ materially from those implied or expressed by the forward-looking statements. These include risks relating to financial performance and results, current economic conditions and resulting capital restraints, prices and demand for oil and natural gas and the related impact to financial statements as a result of asset impairments and revisions to reserve estimates, availability and cost of drilling equipment and personnel, availability of sufficient capital to execute the Company's business plan, impact of compliance with legislation and regulations, successful results from the Company's identified drilling locations, the Company's ability to replace reserves and efficiently develop and exploit its current reserves and other important factors that could cause actual results to differ materially from those projected as described in the Company's Annual Report on Form 10-K for the year ended December 31, 2015 and other reports filed with the Securities Exchange Commission ("SEC") including, but not limited to, its Annual Report on Form 10-K for the year ended December 31, 2016 to be filed with the 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.

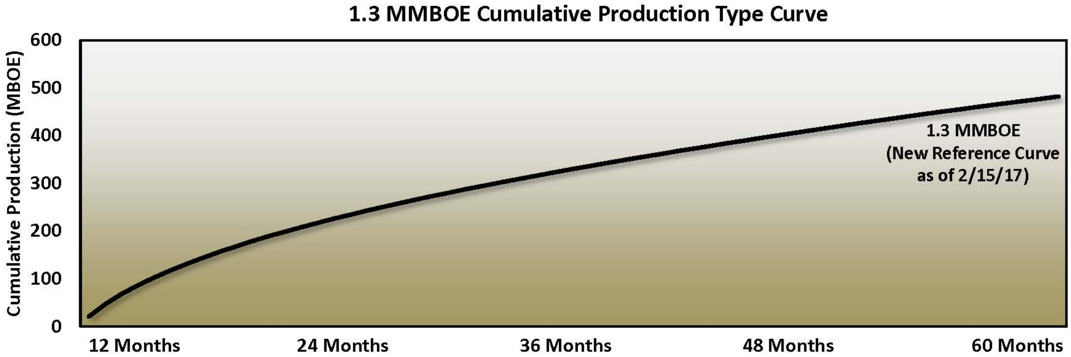
This presentation includes financial measures that are not in accordance with generally accepted accounting principles ("GAAP"), including Adjusted EBITDA. While management believes that such measures are useful for investors, they should not be used as a replacement for financial measures that are in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

2016 Highlights Driven by Prior Investments

- **Multi-zone, contiguous acreage position enabling development efficiencies**
  - 2016 average completed lateral length of ~10,000' driving higher rates of return
- **Data powering the multivariate Earth Model**
  - Increasing UWC & MWC type curves as a result of long-term production outperformance from multivariate Earth Model optimized drilling and completions
  - Most recent well results currently averaging ~36% higher than the new 1.3 MMBOE type curve
- **Production corridors lowering operating costs**
  - Production corridors benefited LOE $0.51/BOE in the fourth quarter of 2016
  - Full-year 2016 unit LOE reduction of ~37% YoY
- **Medallion-Midland Basin system growing transported volumes**
  - Medallion-Midland Basin system more than doubled delivered volumes in 2016 and is expected to grow >75% exit-to-exit in 2017

Prior strategic investments and continuous performance improvements yield repeatable benefits

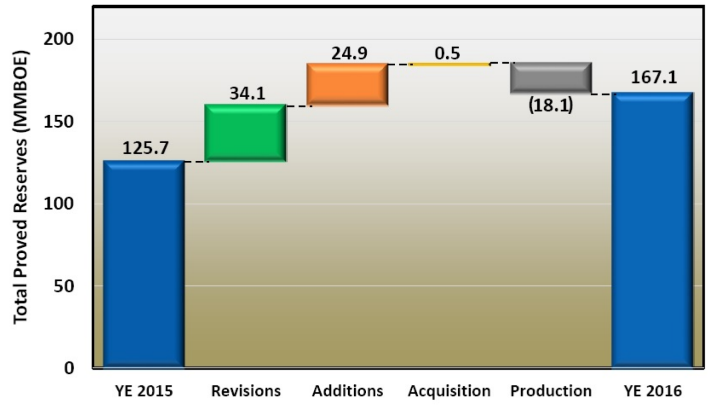
New UWC & MWC 1.3 MMBOE Cumulative Production Type Curve

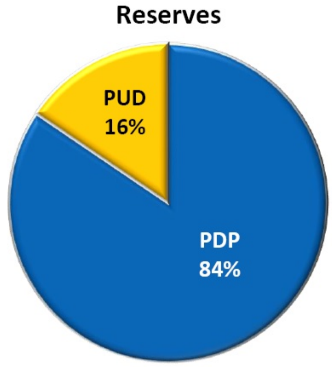


Months	Cumulative Production (MBOE)	Cumulative % Oil
12	189	60%
24	288	56%
36	326	54%
48	426	52%
60	482	51%

Increasing UWC & MWC type curve due to well performance uplifts from the multivariate Earth Model optimized drilling and completions

YE-16 Proved Reserves





Minimizing PUD bookings enables the Company to maximize the value of its 3,500 identified locations capable of generating at least a 10% rate of return[1]

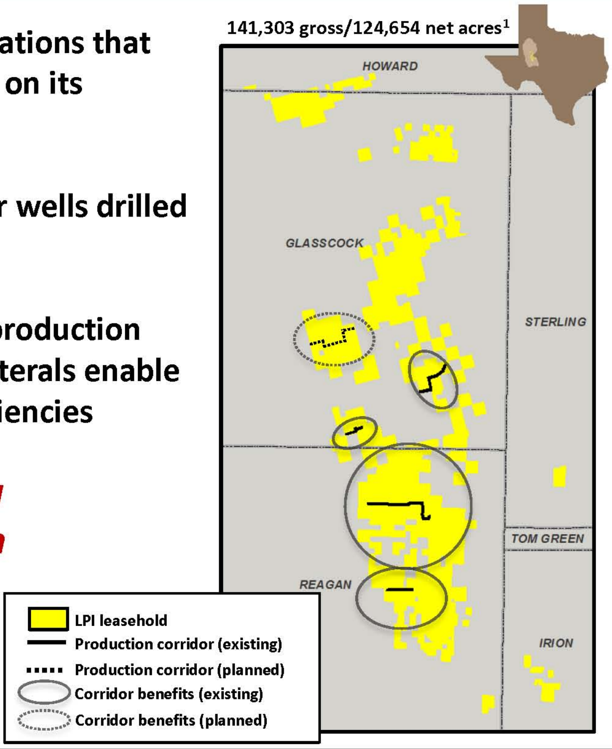
Note: Assuming current commodity price environment, service costs and rig cadence as of 2/15/17

Capitalizing on Contiguous Acreage Position

- The company has identified >2,000 locations that support lateral lengths of 10,000+ feet on its contiguous acreage
- The expected average lateral length for wells drilled in 2017 will be ~10,000 feet
- 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[2]

141,303 gross/124,654 net acres[1]



[1] As of 1/31/17
[2] As of 12/31/16

Multiple Targeted Horizons

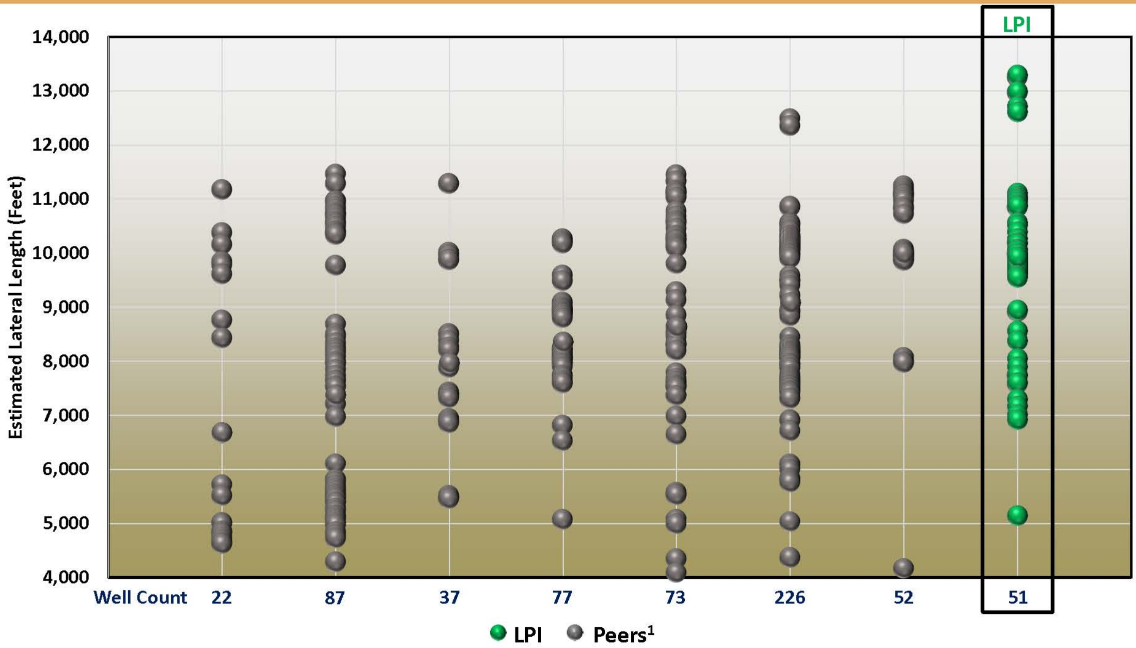
Primary targets: Lower Spraberry, Upper Wolfcamp, Middle Wolfcamp, Cline
Secondary targets: Lower Wolfcamp, Canyon, Atoka, Barnett, Woodford

4,500 gross ft. of prospective zones

Zone	Hz Wells Drilled	Thickness	OOIP[1]	Identified Landing Points
Clearfork				
Upper/Middle Spraberry				
Lower Spraberry	2	~415’	90	2 - 3
Dean				
Upper Wolfcamp	127	~405’	72	2 - 3
Middle Wolfcamp	61	~620’	69	2 - 3
Lower Wolfcamp	30	~520’	69	1
Canyon	2	~470’	40	1
Penn Shale				
Cline	57	~330’	47	2
Strawn				
Atoka, Barnett, Woodford	1	~375’	41	1

[1] Representative of the estimated mean original oil in place (OOIP) per section, measured in stock tank million barrels of oil equivalent
Note: As of 12/31/16

Peer-Leading Long-Lateral Execution

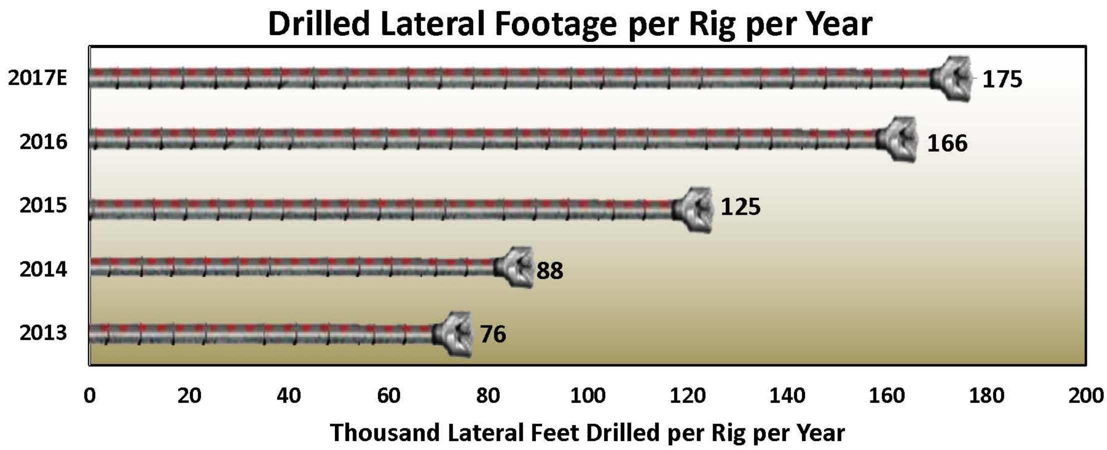


Contiguous acreage position enables drilling of longer laterals

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

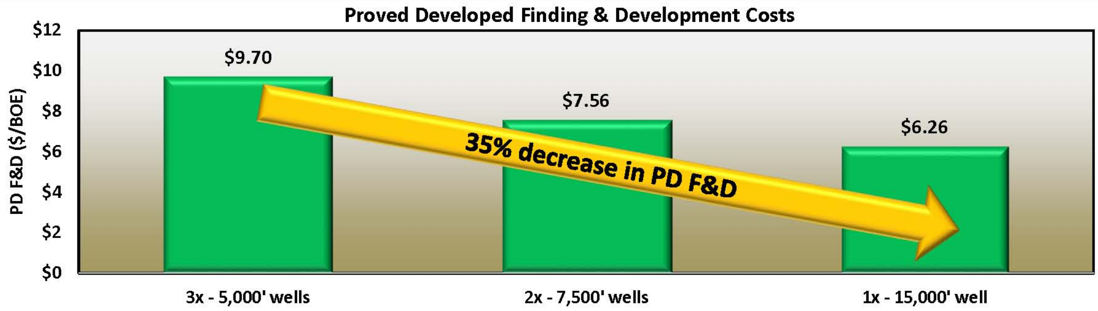
Note: Data is from IHS Enerdeq for the period of 01/01/2016 – 12/31/2016 for Glasscock, Howard, Irion, Midland, Reagan and Martin & Upton counties, TX

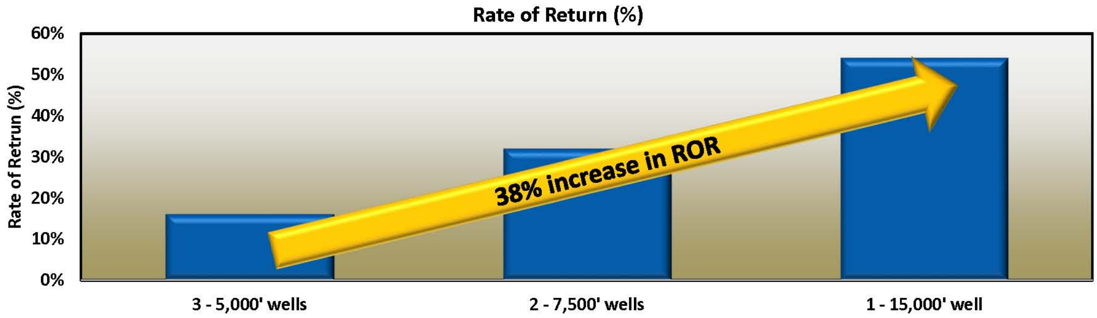
Drilling Efficiencies Drive Lower Well Costs



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

Economic Benefits of Longer Laterals

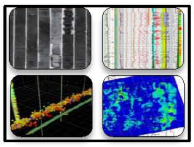


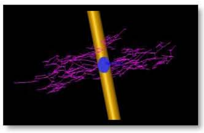


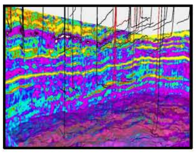
Longer laterals develop equivalent resources for reduced capital, yielding capital efficiency and rate of return improvements

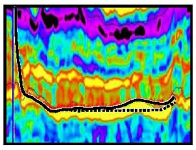
Note: Utilizing 75% NRI and EUR of 1.3 MMBOE per 10,000' lateral (updated type curve as of 2/15/17)
Utilizing flat benchmark of WTI: $56.10/Bbl & HH: $3.00/Mcf and flat realized pricing of WTI: $50.49/Bbl, HH: $2.16/Mcf & NGLs: $17.95/Bbl

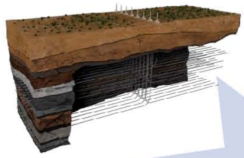
Laredo's Technology Workflow











Technical Data Sets
- Production
- Pressure
- Rock properties
- Stress

Integration
- Prior Knowledge
- Data Collation
- New Well Results
- Paradigms

Technology & Analysis
- Frac Modeling
- Reservoir Simulation
- Multivariate Analytics

Results
- Role of Interference
- Optimized Completions
- Optimized Well Spacing
- Optimized Well Trajectory

Actions
- Predicted Well Performance
- Ranked Zones
- Ranked Wells
- Holistic Development Plan

Earth Modeling is one of a number of technologies being applied at Laredo to enhance shareholder value

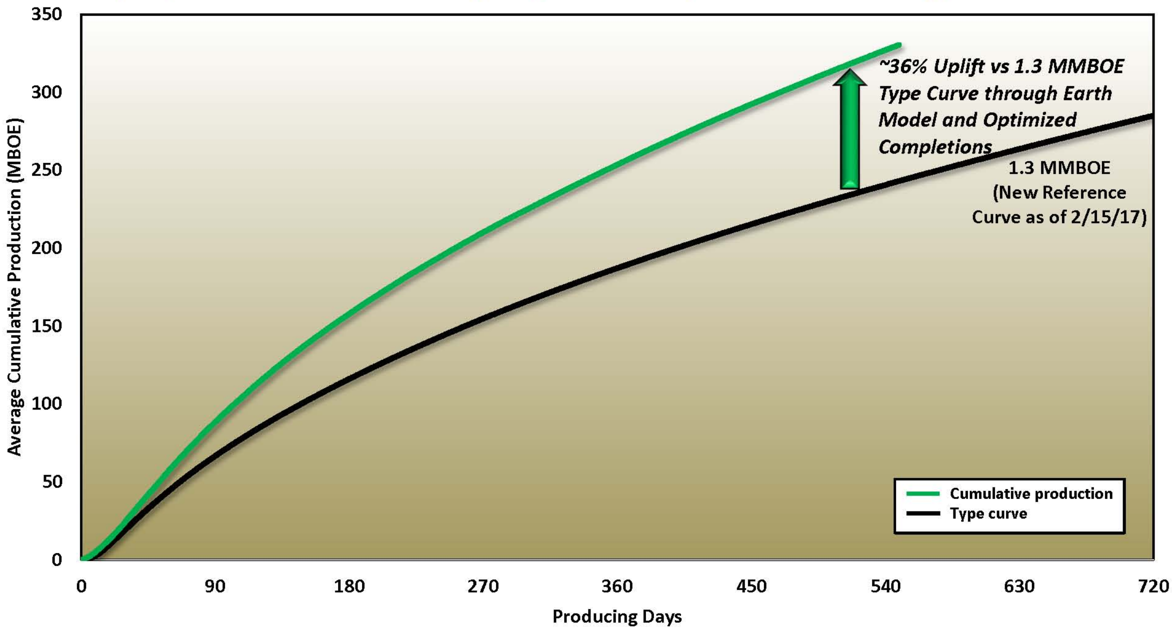
Evolving Beyond the Earth Model

	2015	2016	2017
Project duration	• 12-18 months	• 6-12 months	• 2-4 weeks
LPI acreage coverage	• ~50%	• ~80%	• 100% & offset acreage
# zones	• 2	• 4	• 5
Focus	• Seismic Inversion	• Expanded attributes	• Improved data
Completions	• None	• Intermediate • e.g. proppant loading	• Detailed • e.g. choke management
Well normalization	• Basic • e.g. completion length	• Intermediate • e.g. well spacing	• Enhanced • e.g. development timing
GTI Data	• No	• No	• Yes

Enhanced multivariate analysis of key production drivers

Earth Model and Completion Optimization Benefits

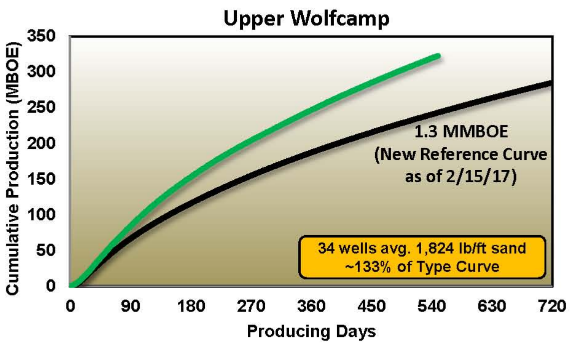
Wells utilizing the Earth Model and optimized completions have performed at an average of ~136% of 1.3 MMBOE Type Curve[1]

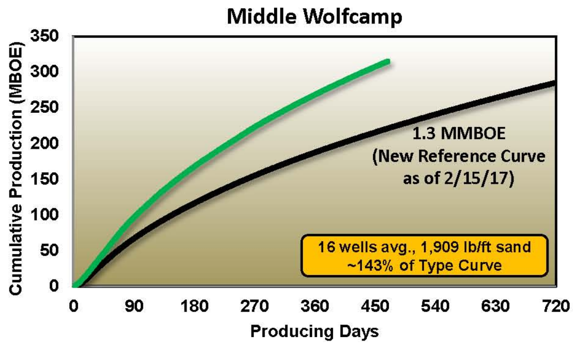


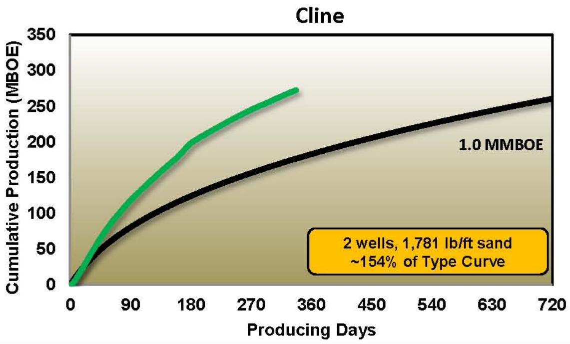
[1] Average cumulative production data through 2/6/17. This includes 50 Hz UWC/MWC wells have utilized both the Earth Model and optimized completions with 1,851 lb/ft sand

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





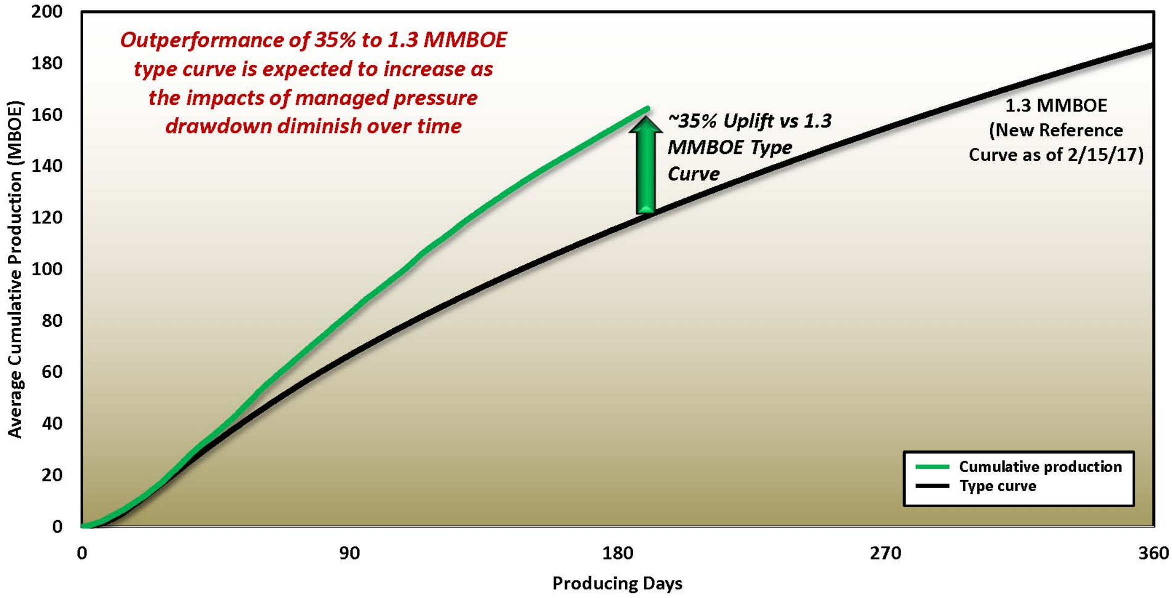


Wells drilled with the Multivariate Earth Model and optimized drilling and completions have resulted in significant outperformance versus the Company's type curves

Cumulative production
Type curve

Note: Average cumulative production data through 2/6/17. Production has been scaled to 10,000' EUR type curves and non-producing days (for shut-ins) have been removed

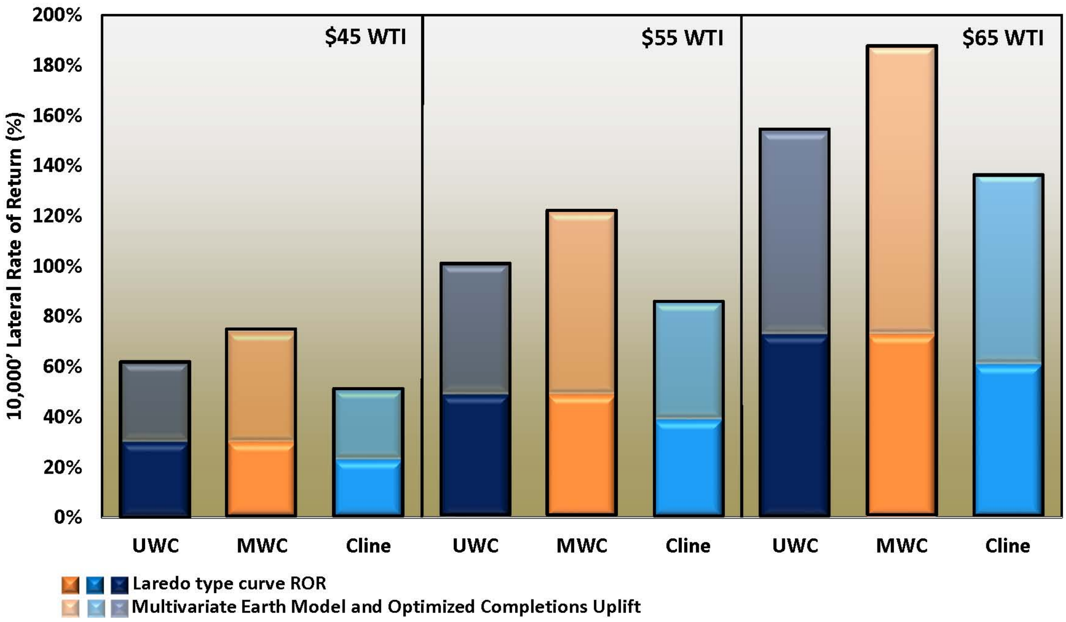
Latest Optimization Tests Significantly Exceeding Type Curve



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

Note: Production through 2/6/2017 for SUGG A 171-172/173, SUGG A 208-209/207, SUGG A 185 utilizing 2,400 lb/ft sand

Multivariate Earth Model Driving Meaningful Uplift in Returns



Demonstrated performance uplifts in each zone yield significant return improvements

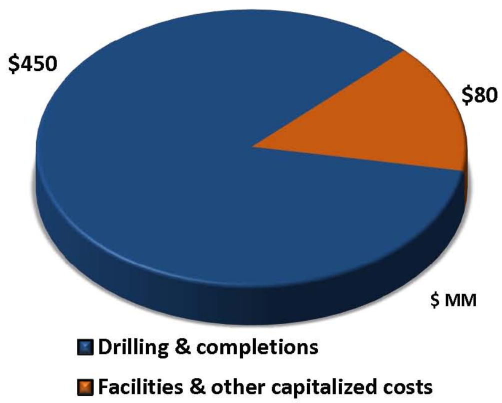
Note: Rate of returns calculated using benchmark prices of WTI: $45.00/Bbl, $55.00/Bbl, $65.00/Bbl & HH: $3.00/Mcf, $3.25/Mcf, $3.50/Mcf
and realized pricing of WTI: $40.50/Bbl, $49.50/Bbl, $58.50/Bbl & HH: $2.16/Mcf, $2.34/Mcf, $2.52/Mcf & NGLs: $14.40/Bbl, $17.60/Bbl, $20.80/Bbl
ROR includes static 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

2017 Budget Expectations

2017 Drilling & Completions

- Operating 4 Hz rigs
- Drilling and completing ~70 Hz wells
- ~85% targeting the UWC & MWC
- ~95% average working interest
- Hz wells average ~10,000' lateral length
- Developed as 4-5 well packages

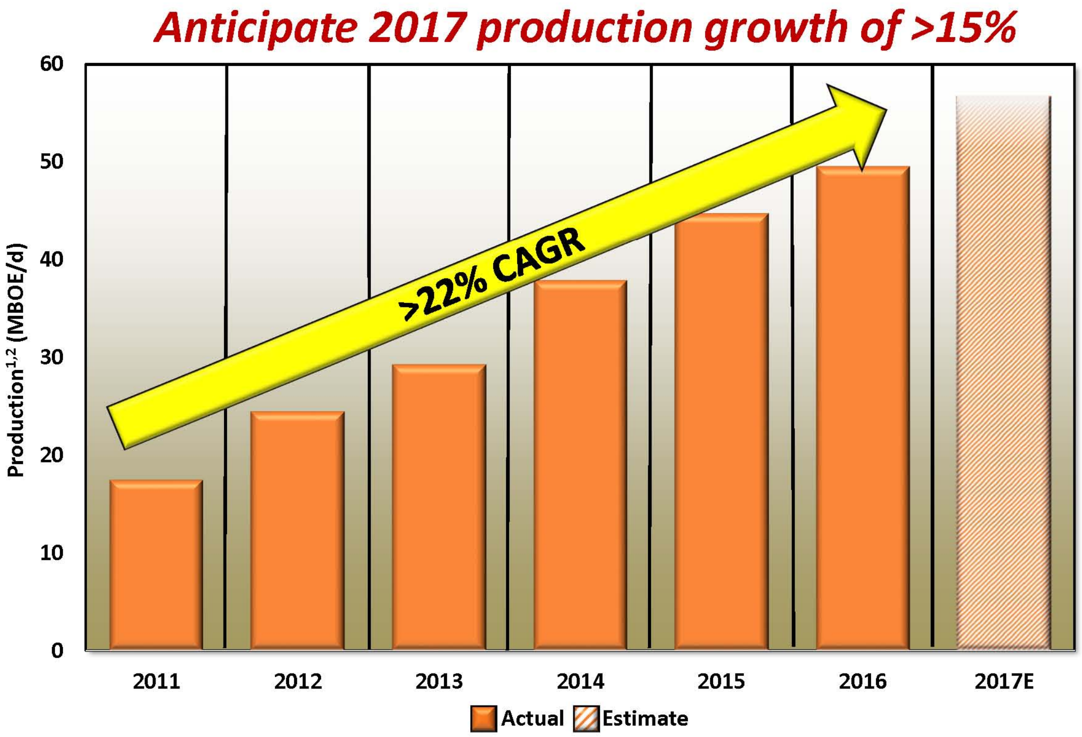
2017 Capital Budget [1]
$530 MM



Over 98% of wells planned for 2017 are expected to be developed as multi-well packages

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

Consistent Production Growth



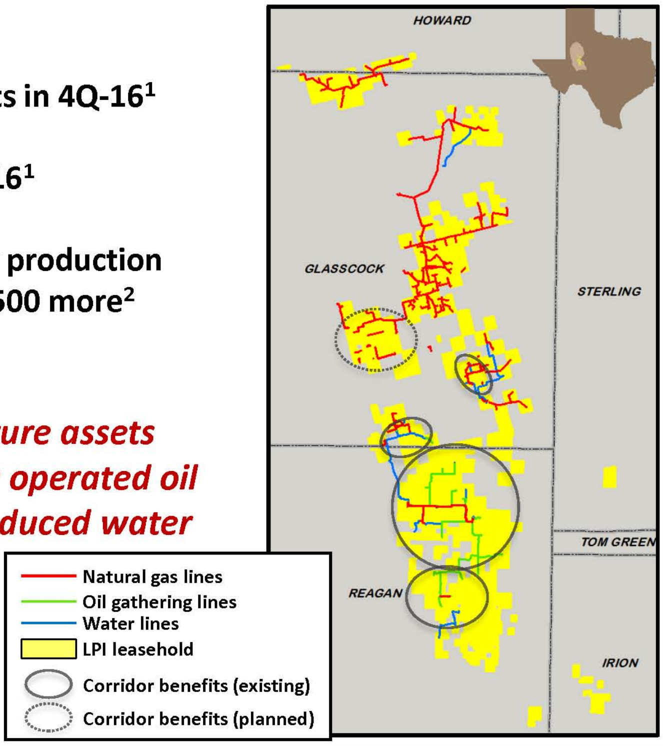
[1] Production numbers prior to 2014 have been converted to 3-stream using an 18% uplift. 2014 results have been converted to 3-stream using actual gas plant economics
[2] 2011 - 2013 adjusted for Granite Wash divestiture, closed August 1, 2013

LAREDO PETROLEUM

Prior Investment in Infrastructure Providing Tangible Benefits

- ~$5.5 MM total realized benefits in 4Q-16[1]
- ~$24 MM total benefits for FY-16[1]
- ~195 horizontal wells served by production corridors with potential for >2,500 more[2]

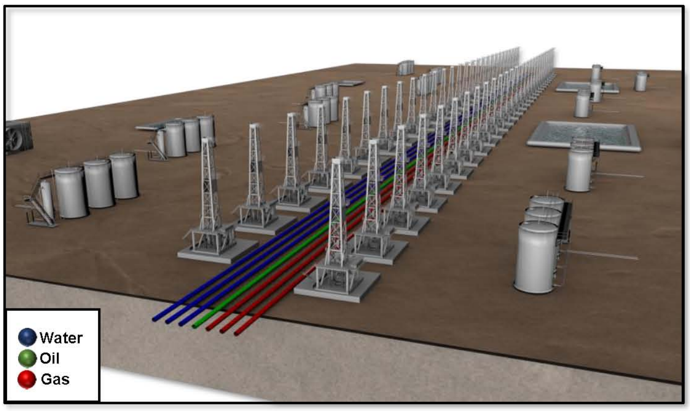
In 4Q-16, Laredo infrastructure assets gathered on pipe 73% of gross operated oil production & 65% of total produced water



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

Corridor Financial Benefits

~$1.3 MM benefit over life of each 10,000' corridor well, with ~25% of the benefit received in the first six months[1]

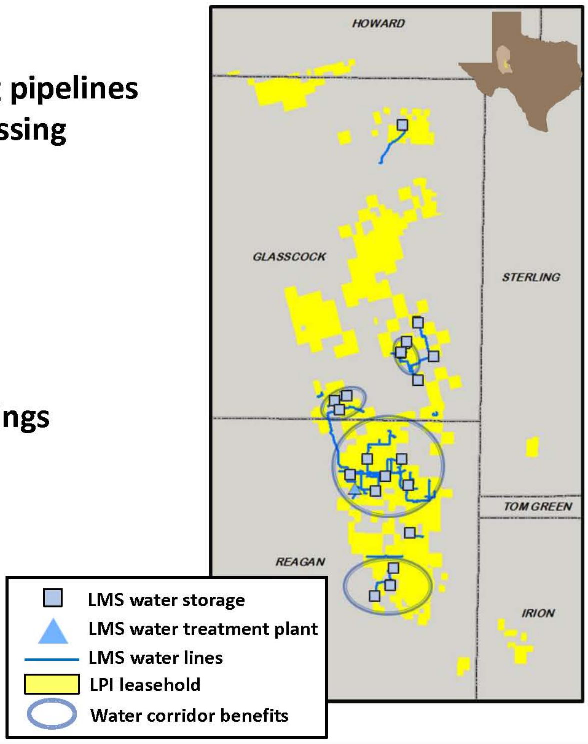


LMS Service	2016 Benefits Actual ($ MM)	2017 Benefits Estimated ($ MM)[1]	LPI Financial Benefits
Crude Gathering	$10.4	$14.1	Increased revenues & 3rd-party income
Centralized Gas Lift	$0.9	$0.9	LOE savings
Frac Water (Recycled vs Fresh)	$1.1	$1.8	Capital savings
Produced Water (Recycled vs Disposed)	$2.0	$2.4	Capital & LOE savings
Produced Water (Gathered vs Trucked)	$9.6	$8.7	Capital & LOE savings
Corridor Benefit	$24.1	$27.9	

[1] Benefits estimates as of December 31, 2016

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 >5 MMBW capacity
- Enables drilling of multi-well pads
- Yields significant capital and LOE savings
- Minimizes trucking

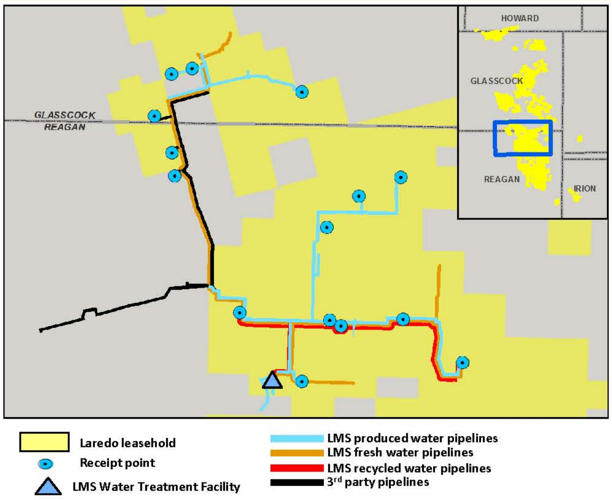


Produced Water Takeaway Capital and LOE Savings

- 11.3 MMBW (61%) of total 2016 produced water was gathered on pipe
  - Expected to increase to ~75% in 2017

- 6.3 MMBW (34%) of total 2016 produced water was recycled by LMS
  - Expected to increase to ~57% in 2017

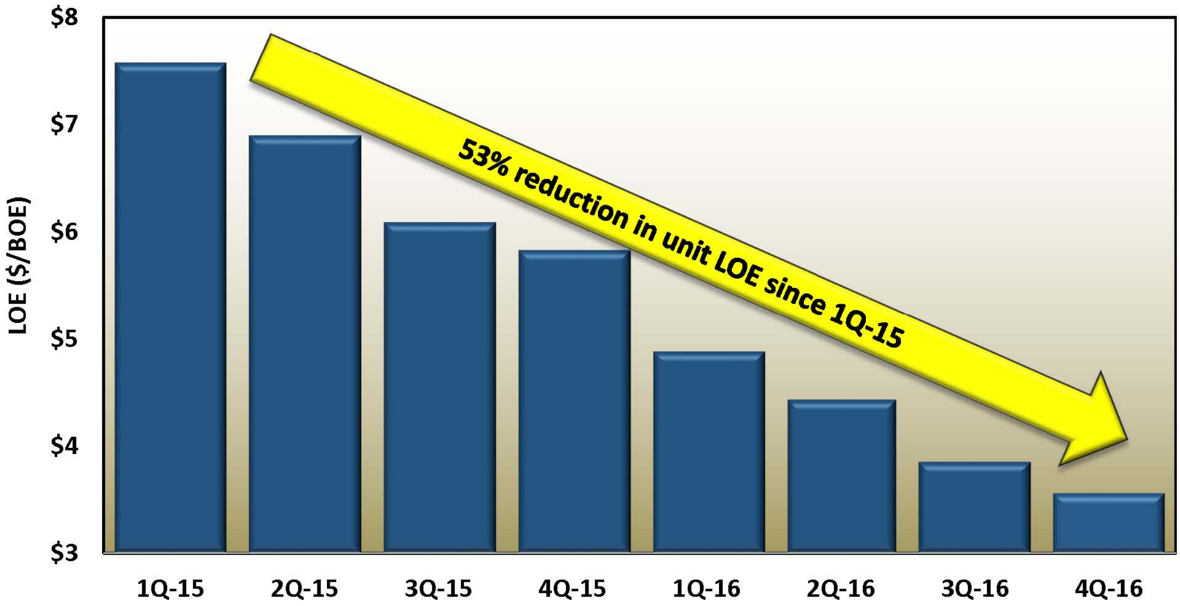
- 4.4 MMBW (15%) of water for completions in 2016 was supplied with recycled water
  - Expected to increase to ~20% in 2017



2016 Benefits	LPI Financial Benefits		
	Location	($/BW)	($ MM)
Produced Water (Recycled vs Disposed)	Capital & LOE savings	$0.32	$2.0
Produced Water (Gathered vs Trucked)	Capital & LOE savings	$0.85	$9.6
Frac Water (Recycled vs Fresh)	Capital savings	$0.26	$1.1

Laredo's water gathering system displaced ~95,000 truckloads of water in 2016

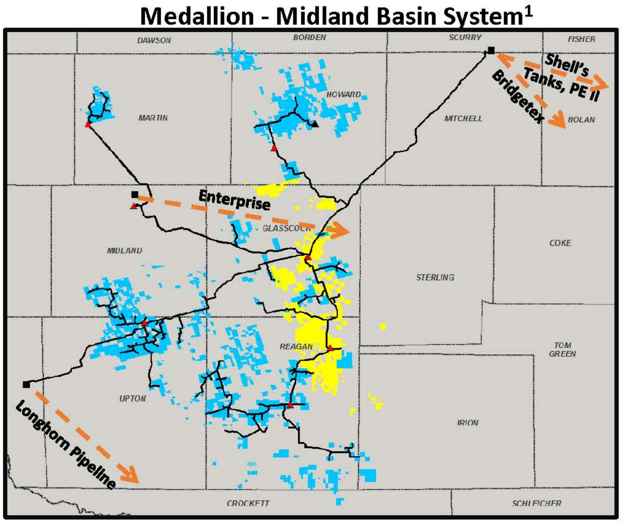
Consistent Unit LOE Reduction



Medallion-Midland Basin System

	YE-15	YE-16
Throughput (MBOPD)	67.6	134.3
Miles of Pipeline	~460	~650[2]
System Deliverability (MBOPD)	125	550
# of AMI or Firm Commitment Acres	~1.8 MM	~2.0 MM
# of Dedicated Producers	8	10
# of Dedicated or Firm Commitment Acres	>290,000	>520,000

Medallion - Midland Basin System[1]

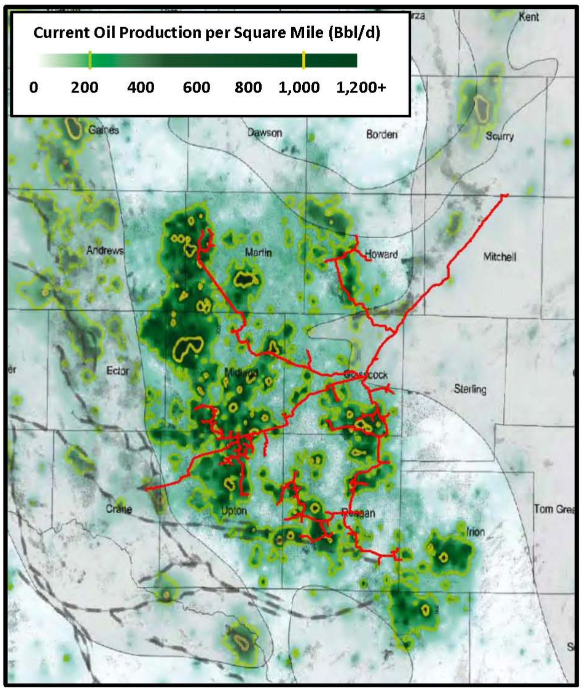


LPI leasehold
3rd-party acreage
Medallion pipelines
Long-haul pipe
Truck offloading
Delivery point
Refinery

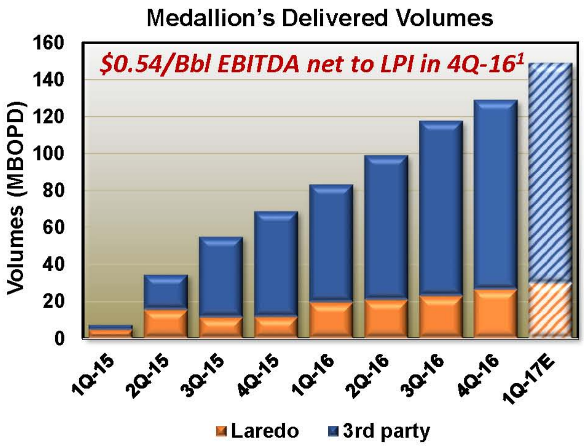
Laredo has firm transportation on Medallion-Midland Basin system to Colorado City and firm transportation of ~30 MBOPD gross to the Gulf Coast

[1]As of 1/17/17
[2]60 miles currently under construction

Medallion-Midland Basin: The Premier Pipeline in the Permian



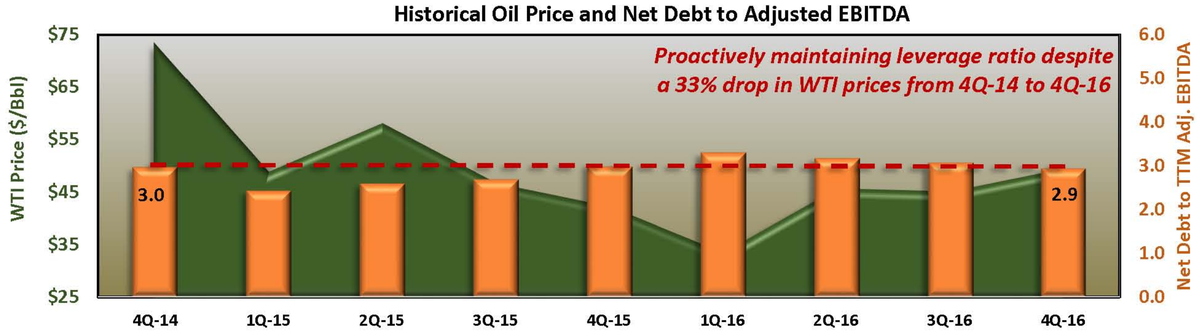
Medallion–Midland Basin system



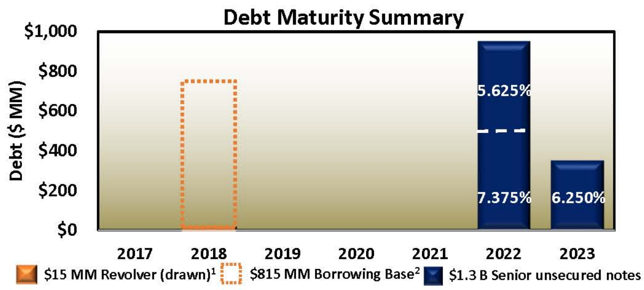
The Medallion-Midland Basin system is expected to grow >75% exit-to-exit in 2017

[1] Includes G&A
Note: Heat map generated by RS Energy Group

Maintaining Strong Financial Position

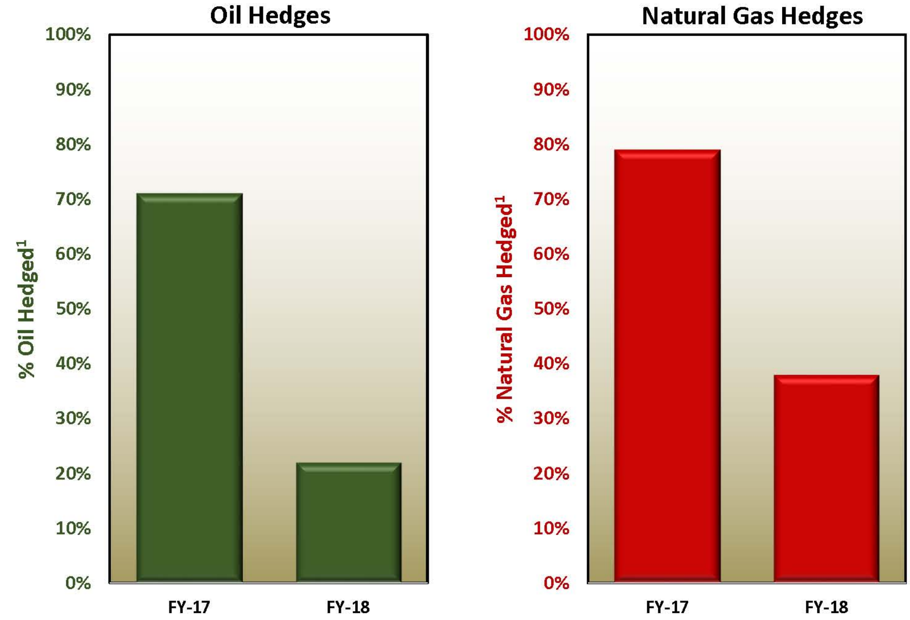


- No term debt due until 2022
  - $950 million of notes callable at Laredo's option in 2017
- $824 MM of liquidity[1]



[1] As of 2/14/17
[2] As of October 2016 redetermination; Medallion interest is not pledged to borrowing base

Disciplined Hedging Program

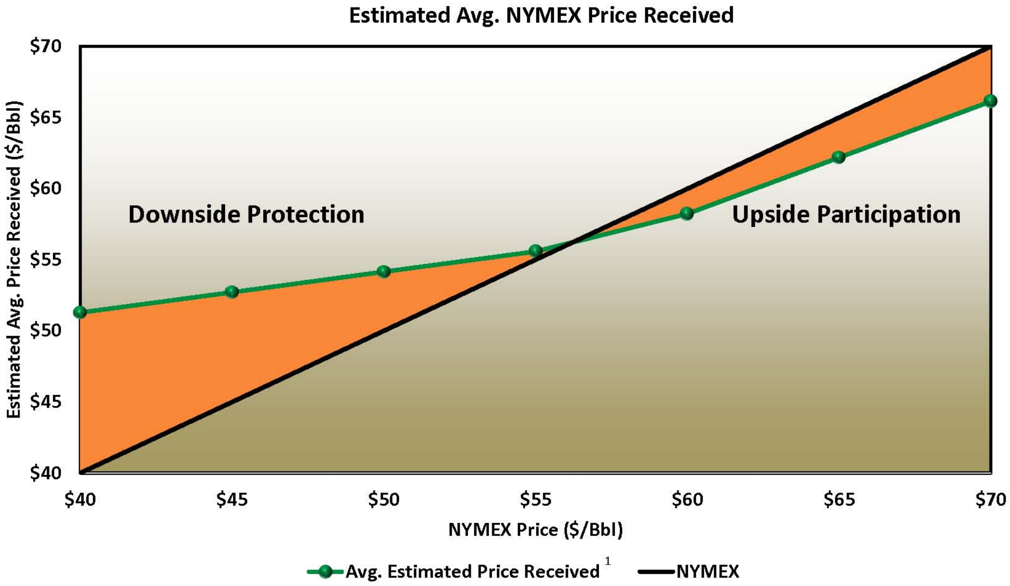


Weighted-Avg. Floor Price[2]	$55.82	$55.98	$2.75	$2.50
	NYMEX		WAHA	

Hedging program provides price protection while retaining substantial upside

[1] Utilizing midpoint of current 2016 production for FY-17 and FY-18 percent hedged
[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
Note: Does not include 2017 NGL hedges of 444,000 Bbl of ethane or 375,000 Bbl of propane

Oil Hedges Retain Meaningful Upside in 2017



2017 oil hedges provide significant downside protection while maintaining upside exposure to an increase in the price of oil

[1] Includes hedged and unhedged barrels
Note: Assumes 15% YoY production growth in 2017

2017 Guidance

	1Q-17	2Q-17
Production (MBOE/d)……	52 - 54	55 - 58
Product % of total production:		
Crude oil……	44% - 46%	45% - 47%
Natural gas liquids……	27% - 28%	*
Natural gas……	27% - 28%	*
Price Realizations (pre-hedge):		
Crude oil (% of WTI)……	~90%	*
Natural gas liquids (% of WTI)……	~32%	*
Natural gas (% of Henry Hub)……	~72%	*
Operating Costs & Expenses:		
Lease operating expenses ($/BOE)……	$3.50 - $4.00	*
Midstream expenses ($/BOE)……	$0.20 - $0.30	*
Production and ad valorem taxes (% of oil, NGL and natural gas revenue)……	6.75%	*
General and administrative expenses:		
Cash ($/BOE)……	$3.35 - $3.85	*
Non-cash stock-based compensation ($/BOE)……	$2.00 - $2.25	*
Depletion, depreciation and amortization ($/BOE)……	$7.50 - $8.00	*

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

Oil, Natural Gas & Natural Gas Liquids Hedges

OIL[1]	2017	2018
Puts:		
Hedged volume (Bbls)	1,049,375	1,049,375
Weighted average price ($/Bbl)	$60.00	$60.00
Swaps:		
Hedged volume (Bbls)	2,007,500	1,095,000
Weighted average price ($/Bbl)	$51.54	$52.12
Collars:		
Hedged volume (Bbls)	3,796,000	
Weighted average floor price ($/Bbl)	$56.92	
Weighted average ceiling price ($/Bbl)	$86.00	
Total volume with a floor (Bbls)	6,852,875	2,144,375
Weighted-average floor price ($/Bbl)	$55.82	$55.98

NATURAL GAS[2]		
Put		
Hedged volume (MMBtu)	8,040,000	8,220,000
Weighted average floor price ($/MMBtu)	$2.50	$2.50
Collars:		
Hedged volume (MMBtu)	19,016,500	4,635,500
Weighted average floor price ($/MMBtu)	$2.86	$2.50
Weighted average ceiling price ($/MMBtu)	$3.54	$3.60
Total volume with a floor (MMBtu)	27,056,500	12,855,500
Weighted-average floor price ($/MMBtu)	$2.75	$2.50

NATURAL GAS LIQUIDS[3]		
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	

Note: Open positions as of 01/01/17
[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

Hydraulic Fracture Test Site (HFTS)

$23.1 MM high-profile, joint-industry project led by Laredo and the Gas Technology Institute (GTI)

Laredo's Project Contribution

- Selected as operator
- Conducted on Laredo's acreage
- No cost to Laredo
- On-time, on-budget
- Strong linkage to completions optimization

Site Host

LAREDO PETROLEUM

Research Team

gti · Bureau of Economic Geology

Sponsors

U.S. Department of Energy · NETL · ConocoPhillips · Core Lab · ENERGEN · encana · Shell · Total · Chevron · Halliburton · Discovery · devon

➔ *In-Progress*
☑ *Complete*

Key Initiatives

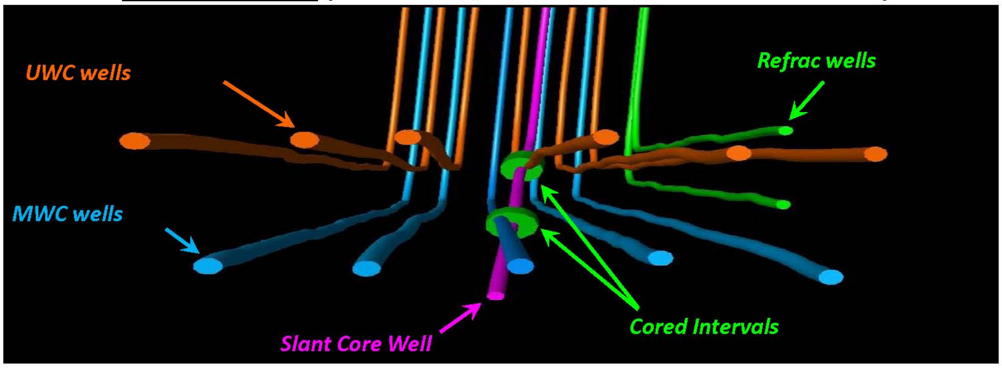
- ➔ Slant Well Fracture & Proppant Analysis
- ➔ Hydraulic Fracture Modeling
- ➔ Fracture Attribute Studies

Data Sets Acquired

- ☑ Drilling, Coring & Logging Slant Well
- ☑ Pilot Hole Logs & Sidewall Cores
- ☑ Offset Well Refracs (μ-seismic & tracers)
- ☑ Horizontal DFIT's
- ☑ Radioactive Tracers & Fluid Tracers
- ☑ Microseismic Monitoring
- ☑ Cross-Well Seismic
- ☑ Surface Seismic Monitoring
- ☑ Colored Proppant Cluster Indicators
- ☑ Inter-well Pressure Monitoring
- ☑ Fiber Optic Production Logging
- ☑ Environmental Sampling
- ☑ Oil Fingerprinting / Fluid Sampling

Advanced Hydraulic Fracture Data Collected on Laredo Leasehold

<u>HFTS GTI LAYOUT</u> (6 UWC wells, 5 MWC wells, UWC & MWC refracs)



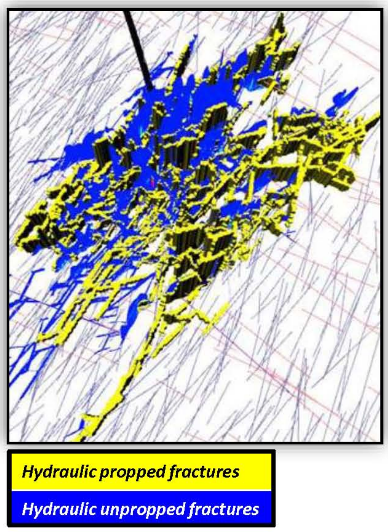
<u>HYDRAULICALLY FRACTURED CORE</u>

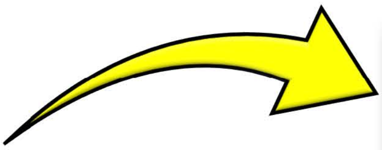

Recovered core showing complexity of hydraulically created fractures

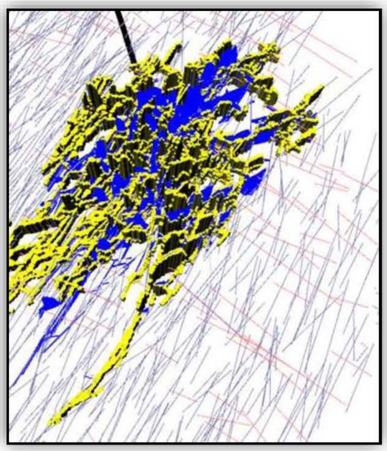
- ~600 feet recovered
- UWC & MWC
- Natural fractures
- Hydraulic fractures
- Proppant recovered

Cutting-edge completions data being integrated into the multivariate Earth Model

Advanced Fracture Modeling

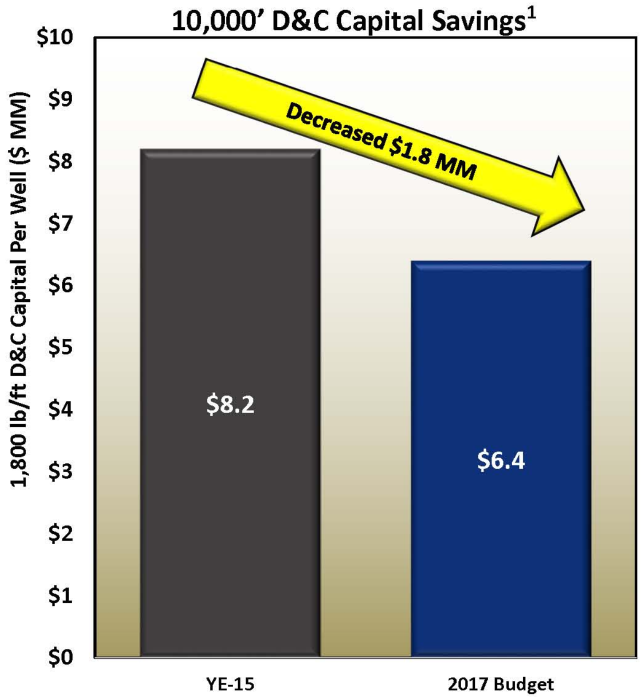






Utilizing multivariate Earth Model analysis to optimize completions designs

Drilling & Completion Costs



- **Efficiency gains partially offset recent increases in service costs**
- **D&C capital includes:**
  - **$1 MM for 1,800 lb/ft sand**
  - **Pad preparation**
  - **Well-site metering**
  - **Heater treaters**
  - **Separation equipment**
  - **Artificial lift equipment**

Focused on capital efficient drilling & completion operations

[1] Representative of multi-well pad costs

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

2015 & 2016 YTD Actuals

		1Q-15	2Q-15	3Q-15	4Q-15	FY-15	1Q-16	2Q-16	3Q-16	4Q-16	FY-16
Production	Production (3-Stream)										
	MBOE	4,274	4,234	4,124	3,714	16,346	4,204	4,338	4,718	4,889	18,149
	BOE/D	47,487	46,532	44,820	40,368	44,782	46,202	47,667	51,276	53,141	49,586
	% oil	51%	46%	45%	45%	47%	48%	46%	46%	46%	47%
Realized Pricing	3-Stream Prices										
	Gas ($/Mcf)	$2.14	$1.82	$2.01	$1.76	$1.93	$1.31	$1.31	$2.07	$2.13	$1.73
	NGL ($/Bbl)	$13.34	$12.85	$10.36	$11.06	$11.86	$8.50	$12.24	$11.54	$14.79	$11.91
	Oil ($/Bbl)	$41.73	$50.77	$42.88	$36.97	$43.27	$27.51	$39.37	$39.10	$43.98	$37.73
	Avg. Price ($/BOE)	$27.64	$29.65	$25.37	$22.47	$26.41	$17.40	$23.64	$24.34	$27.82	$23.50
Unit Cost Metrics	3-Stream Unit Cost Metrics										
	Lease Operating ($/BOE)	$7.58	$6.90	$6.09	$5.83	$6.63	$4.88	$4.43	$3.85	$3.56	$4.15
	Midstream ($/BOE)	$0.37	$0.38	$0.26	$0.43	$0.36	$0.14	$0.27	$0.22	$0.26	$0.22
	General & Administrative ($/BOE)										
	Cash	$3.99	$3.99	$3.89	$4.29	$4.03	$3.73	$3.32	$3.49	$3.28	$3.45
	Non-cash stock-based compensation	$1.12	$1.49	$1.67	$1.75	$1.50	$0.90	$1.41	$2.05	$1.98	$1.61
	DD&A ($/BOE)	$16.83	$17.03	$16.19	$18.01	$16.99	$9.87	$7.88	$7.45	$7.68	$8.17

EBITDA Reconciliation

LPI Adjusted EBITDA *(in thousands)*		4Q-16		FY 2016
Net income	$	(18,421)	$	(260,739)
Plus:				
Depletion, depreciation and amortization	$	37,526	$	148,339
Impairment expense	$	-	$	162,027
Non-cash stock-based compensation, net of amounts capitalized	$	9,667	$	29,229
Accretion of asset retirement obligations	$	896	$	3,483
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net	$	43,642	$	87,425
Cash settlements received for matured derivatives, net	$	37,655	$	195,281
Cash settlements received for early termination derivatives, net	$	-	$	80,000
Cash premiums paid for derivatives	$	(2,697)	$	(89,669)
Interest expense	$	23,004	$	93,298
Write-off debt issuance costs	$	-	$	842
Loss on disposal of assets, net	$	411	$	790
Income from equity method investee	$	(3,144)	$	(9,403)
Proportionate Adjusted EBITDA of equity method investee(1)	$	6,386	$	20,367
Adjusted EBITDA	$	134,925	$	461,270

[1]Medallion Adjusted EBITDA *(in thousands)*		4Q-16		FY 2016
Income from equity method investee	$	3,144	$	9,403
Adjusted for proportionate share of:				
Depreciation and amortization	$	3,242	$	10,964
Proportionate Adjusted EBITDA of equity method investee	$	6,386	$	20,367