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): March 12, 2018

LAREDO PETROLEUM, INC.
(Exact name of registrant as specified in charter)

Delaware	**001-35380**	**45-3007926**
(State or other jurisdiction of incorporation or organization)	(Commission File Number)	(I.R.S. Employer Identification No.)

15 W. Sixth Street, Suite 900, Tulsa, Oklahoma	**74119**
(Address of principal executive offices)	(Zip code)

Registrant’s telephone number, including area code: **(918) 513-4570**

Not Applicable
(Former name or former address, if changed since last report)

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

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

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

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

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

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

Emerging Growth Company o

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

Item 7.01. Regulation FD Disclosure.

On March 12, 2018, the Company posted to its website a Corporate Presentation (the "Presentation"). The Presentation is available on the Company's website, www.laredopetro.com, and is attached to this Current Report on Form 8-K as Exhibit 99.1 and incorporated into this Item 7.01 by reference.

All statements in this Item 7.01 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. See the Company's Annual Report on Form 10-K for the year ended December 31, 2017 and the Company's other filings with the Securities and Exchange Commission for a discussion of other risks and uncertainties. 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 this Item 7.01 of this Current Report on Form 8-K and the exhibit 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 exhibit 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	Corporate Presentation March 2018.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

LAREDO PETROLEUM, INC.

Dated: March 12, 2018	By:	/s/ Richard C. Buterbaugh
		Richard C. Buterbaugh
		Executive Vice President and Chief Financial Officer

EXHIBIT 99.1

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

Corporate Presentation
March 2018

LAREDO
PETROLEUM

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, possible impacts of pending or potential litigation and other guidance included in this presentation. These statements are based on certain assumptions made by the Company based on management's expectations and perception of historical trends, current conditions, anticipated future developments and rate of return and other factors believed to be appropriate. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the Company, which may cause actual results to differ materially from those implied or expressed by the forward-looking statements. These include risks relating to financial performance and results, current economic conditions and resulting capital restraints, prices and demand for oil and natural gas 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, impacts of pending or potential litigation, impacts relating to the Company's share repurchase program (which may be suspended or discontinued by the Company at any time without notice), successful results from the Company's identified drilling locations, the Company's ability to replace reserves and efficiently develop and exploit its current reserves and other important factors that could cause actual results to differ materially from those projected as described in the Company's Annual Report on Form 10-K for the year ended December 31, 2017 and other reports filed with the Securities and Exchange Commission ("SEC").

Any forward-looking statement speaks only as of the date on which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

The SEC generally permits oil and natural gas companies 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," "type curve" or other descriptions of potential reserves or volumes of reserves which the SEC guidelines restrict from being included in filings with the SEC without strict compliance with SEC definitions. "Unproved reserves" refers to the Company's internal estimates of hydrocarbon quantities that may be potentially discovered through exploratory drilling or recovered with additional drilling or recovery techniques. "Resource potential" is used by the Company to refer to the estimated quantities of hydrocarbons that may be added to proved reserves, largely from a specified resource play potentially supporting numerous drilling locations. A "resource play" is a term used by the Company to describe an accumulation of hydrocarbons known to exist over a large areal expanse and/or thick vertical section potentially supporting numerous drilling locations, which, when compared to a conventional play, typically has a lower geological and/or commercial development risk. The Company does not choose to include unproved reserve estimates in its filings with the SEC. "Estimated ultimate recovery", or "EUR", refers to the Company's internal estimates of per-well hydrocarbon quantities that may be potentially recovered from a hypothetical and/or actual well completed in the area. Actual quantities 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. "Type curve" refers to a production profile of a well, or a particular category of wells, for a specific play and/or area. In addition, the Company's production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases.

This presentation includes financial measures that are not in accordance with generally accepted accounting principles ("GAAP"), including Adjusted EBITDA and Proved F&D Cost. 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 and Proved F&D Cost to the nearest comparable measure in accordance with GAAP, please see the Appendix.

2017 Highlights




~17% Production growth

~36% Organic PDP reserve growth

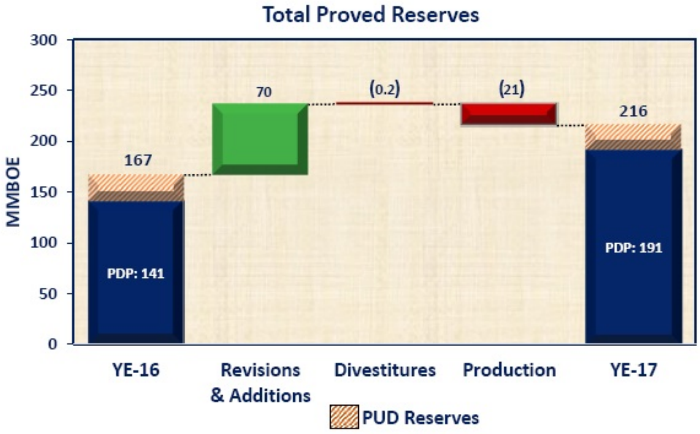
~15% Decrease in unit LOE

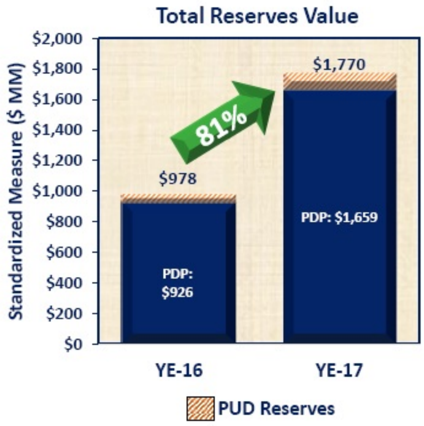
>30% Average anticipated well-level rate of return on invested capital

~50% Decrease in net debt to annualized Adjusted EBITDA[1]

[1] Net debt to Adjusted EBITDA includes net debt as of 12/31/17 and 4Q-17 annualized Adjusted EBITDA and net debt as of 12/31/16 and 4Q-16 annualized Adjusted EBITDA. Net debt as of 12/31/17 is calculated as the face value of long-term debt of $800 MM, reduced by cash on hand of $112 MM. Net debt as of 12/31/16 is calculated as the face value of long-term debt of $1,370 MM, reduced by cash on hand of $33 MM. Please see the Appendix for a reconciliation of Adjusted EBITDA

Low-Cost Proved Reserves Growth



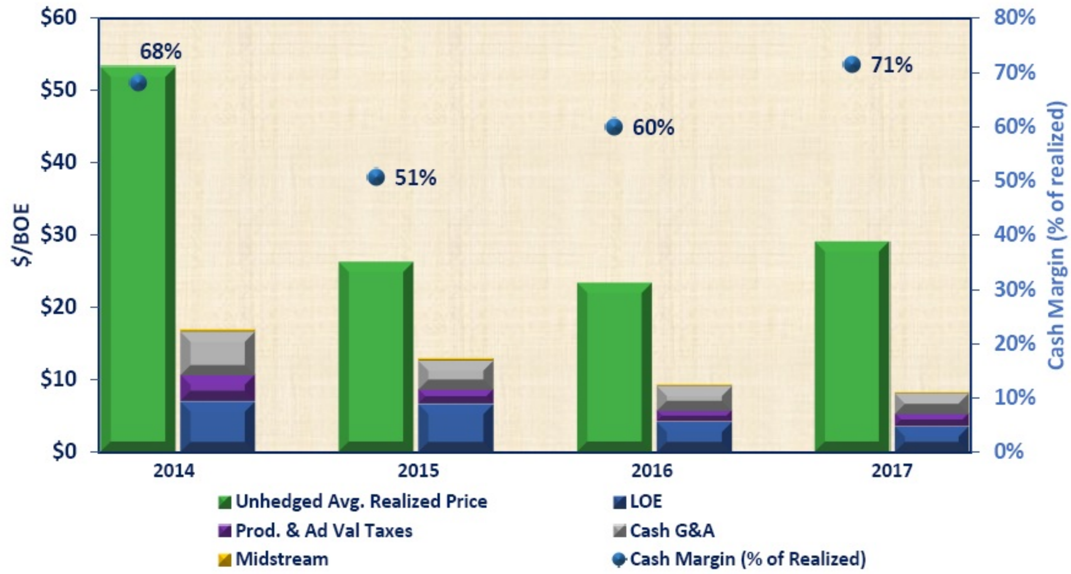


36% Organic growth in proved developed reserves

2017 proved developed F&D cost **$7.90/BOE**

Note: Proved Developed F&D Cost is a non-GAAP financial measure. See the Appendix for information on this calculation

Cash Margin Improved By Reduced Cash Costs



71% Current cash margin % exceeds pre-price decline cash margin[1]

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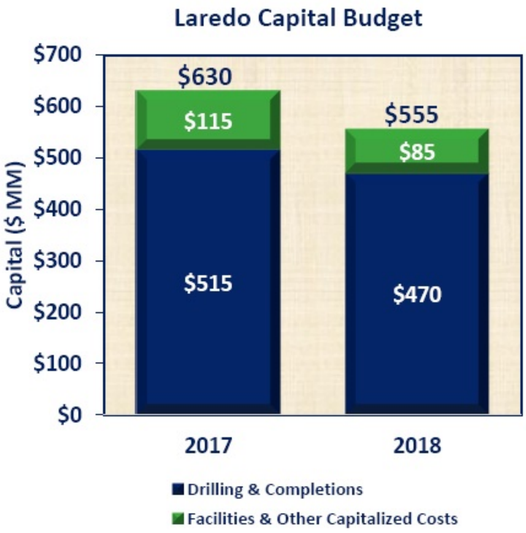
[1] Current cash margin as a percent of unhedged average realized price

Note: 2014 cash margin has been converted to 3-stream using actual gas plant economics

2018 Budget Aligns Capital with Operating Cash Flow

2018 Drilling & Completion Plan

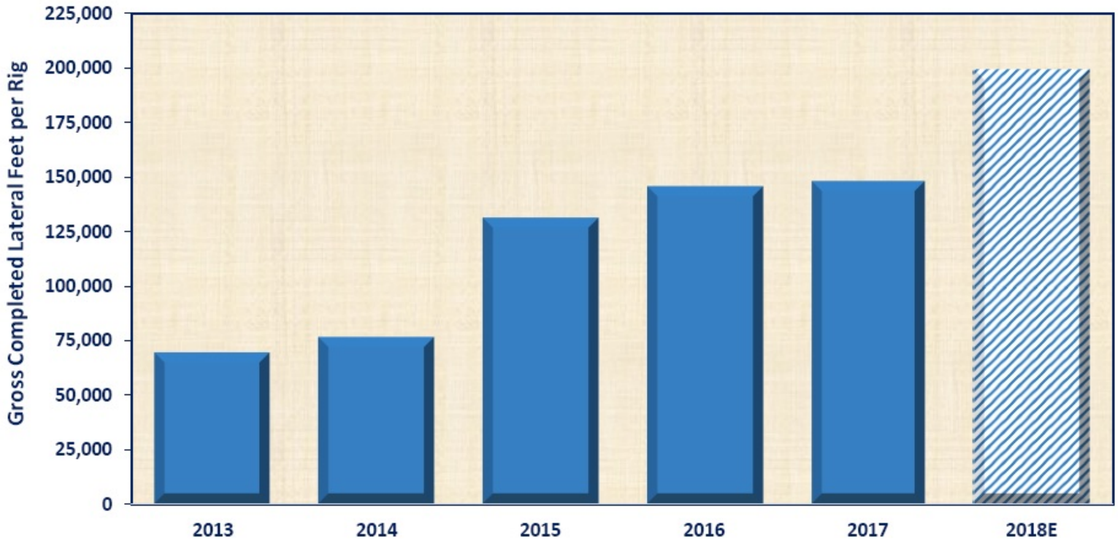
- Completing 60 - 65 net wells
- ~10,400' average Hz lateral length
- ~92% average working interest
- Plan to add 4th rig in 2H-18



12% YoY decrease in 2018 capital budget

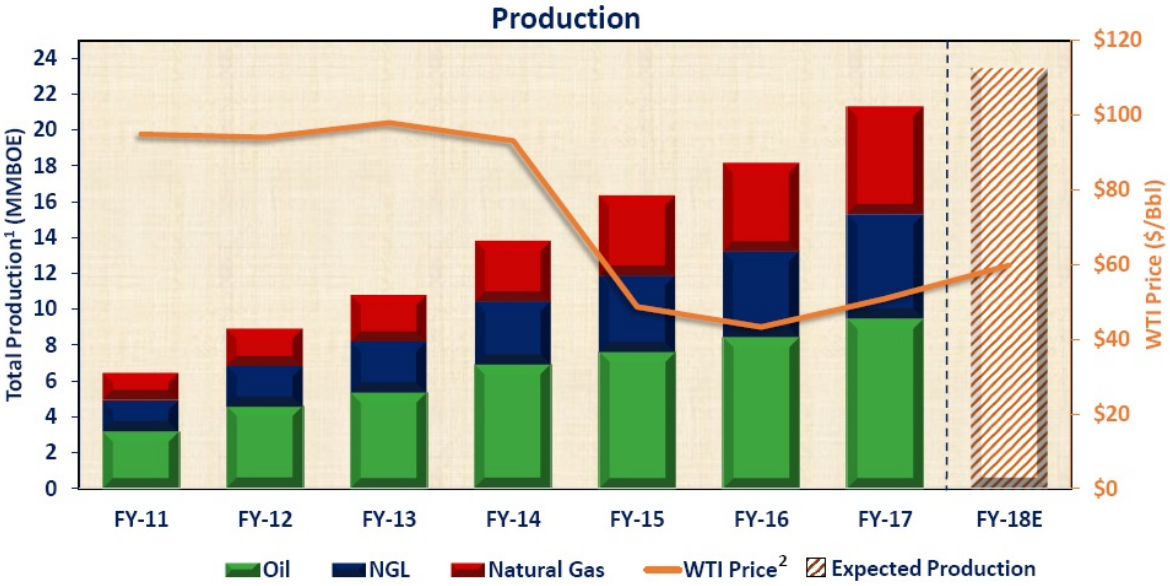
Note: Budget assumes $55/Bbl WTI and $3/MMBtu HH

Operational Efficiencies Enable Us to Do More with Less



35% YoY increase in gross completed lateral feet per rig

Consistent Growth Through Commodity Price Cycle



>10% FY-18E YoY Production Growth

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

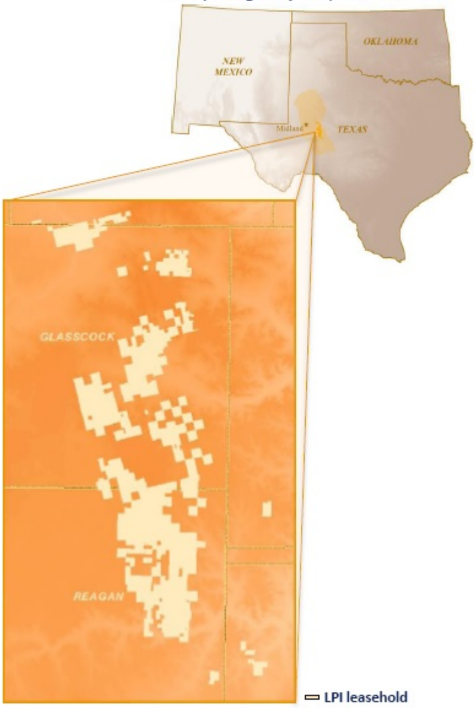
[2] FY-18E WTI spot price as of 3/8/18

Capitalizing on Our Contiguous Acreage Position

- Longer laterals enhance returns
  - ~500 land-ready UWC/MWC locations of at least 15,000'
- Centralized infrastructure enables increased capital and operational efficiencies
  - Five active production corridors
  - Six consecutive quarters of unit LOE below $4.00 per BOE

~86%
HBP acreage, enabling a concentrated development plan along production corridors

144,538 gross/124,843 net acres



Contiguous Acreage Facilitates Robust Infrastructure Investments

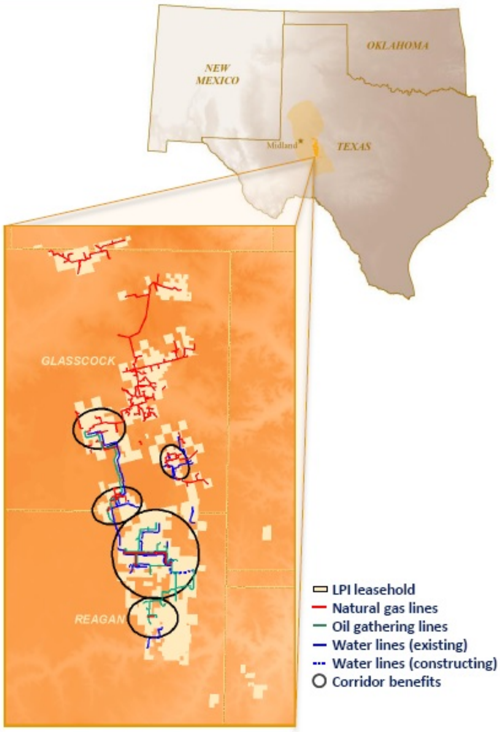
PIPELINE INFRASTRUCTURE

~60 Miles
CRUDE GATHERING

~95 Miles
WATER GATHERING / RECYCLED DISTRIBUTION

~188 Miles
NATURAL GAS GATHERING & DISTRIBUTION

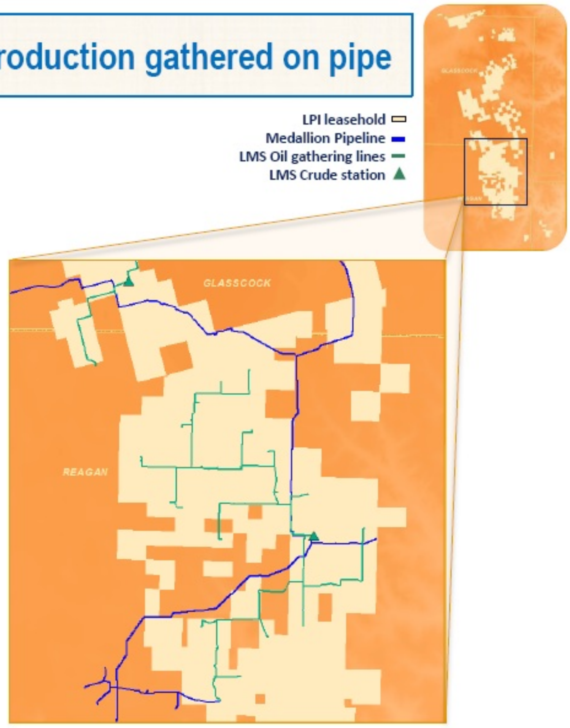
~185,000
Truckloads removed from roads in 2017 due to LMS' water and crude gathering infrastructure



LMS Crude Gathering System Benefits

81% YE-17 gross operated crude production gathered on pipe

- **Reduces time from production to sales**
- **System benefits increase as trucking costs rise**
- **Provides LPI with increased oil price realizations and LMS with 3rd-party income**



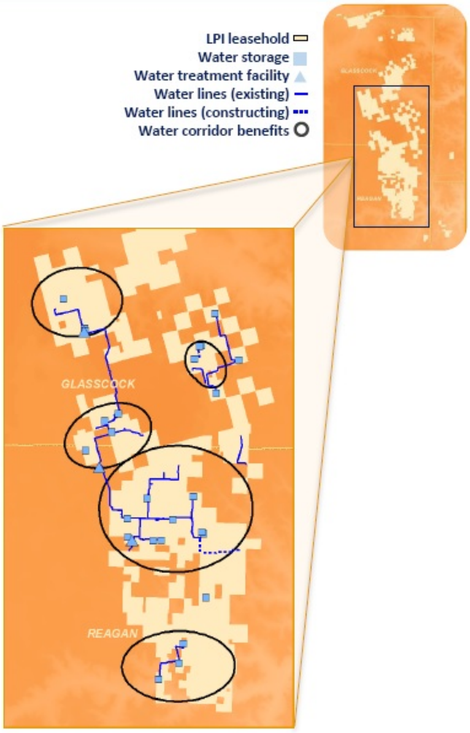
Note: Statistics and maps as of 12/31/17

Significant Benefits Through Water Infrastructure Investments

78%
YE-17 produced water gathered on pipe

LMS Corridor Benefit	LPI Benefit	YE-17 (% of Total Activity)	Capacity
Produced Water Gathered on Pipe	Capital & LOE savings	78%	
Produced Water Recycled	Capital & LOE savings	44%	54 MBWPD Recycling Processing & ~15.7 MMBW Storage Capacity
Completions Utilizing Recycled Water	Capital savings	15%	
Completions Utilizing LPI Fresh Water Wells	Capital savings	17%	

~$10.2 MM
FY-17 LOE reduction generated by LMS' water infrastructure investments[1]



[1]Calculated utilizing a 95% WI & 72% NRI
Note: Statistics, estimates and maps as of 12/31/17

Infrastructure Provides Tangible Benefits

Yields capital & LOE savings, plus increased revenues & 3rd-party income
Enables multi-well pad drilling & operational flexibility
Minimizes trucking

LMS Corridor Benefit	LPI Benefit	4Q-17 Net Benefits Actual ($ MM)	2017 Net Benefits Actual ($ MM)
Crude gathering	Increased revenues & 3rd-party income	$2.7	$10.6
Centralized gas lift	LOE savings	$0.2	$0.9
Produced water gathered on pipe	Capital & LOE savings	$2.9	$10.2
Produced water recycled	Capital & LOE savings	$0.5	$1.7
Completions utilizing recycled water	Capital savings	$0.4	$1.4
Completions utilizing LPI fresh water wells	Capital savings	$0.7	$3.1
Corridor Benefits Total		$7.5	$27.9


LMS Water Treatment Plant


LMS Crude Gathering Tanks at Reagan Truck Station


LMS Gas Lift Compressor Station

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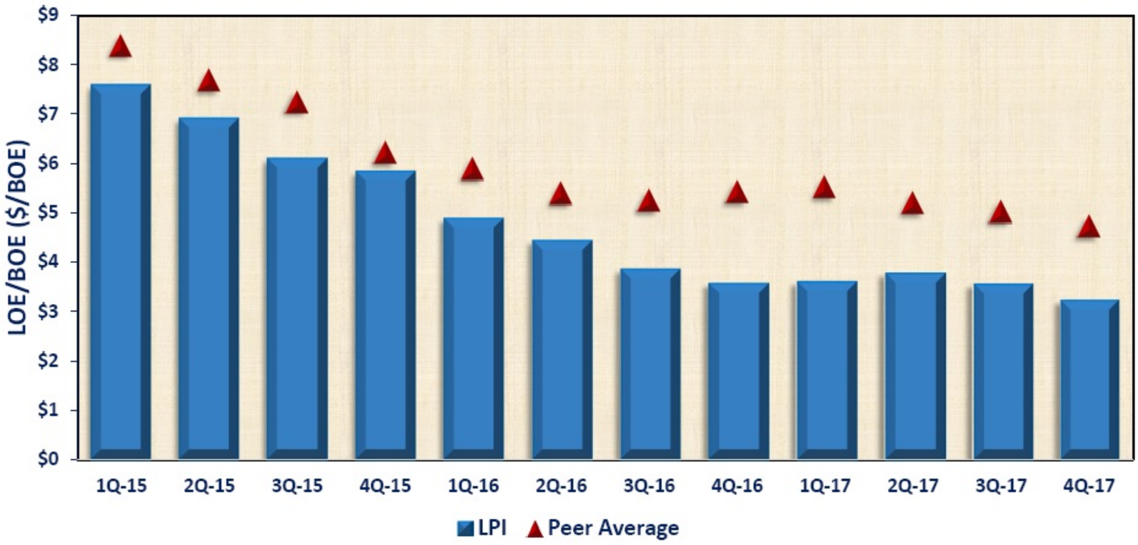
Note: Benefits as of 1/15/18. Totals may not foot due to rounding. Calculated utilizing a 95% WI & 72% NRI

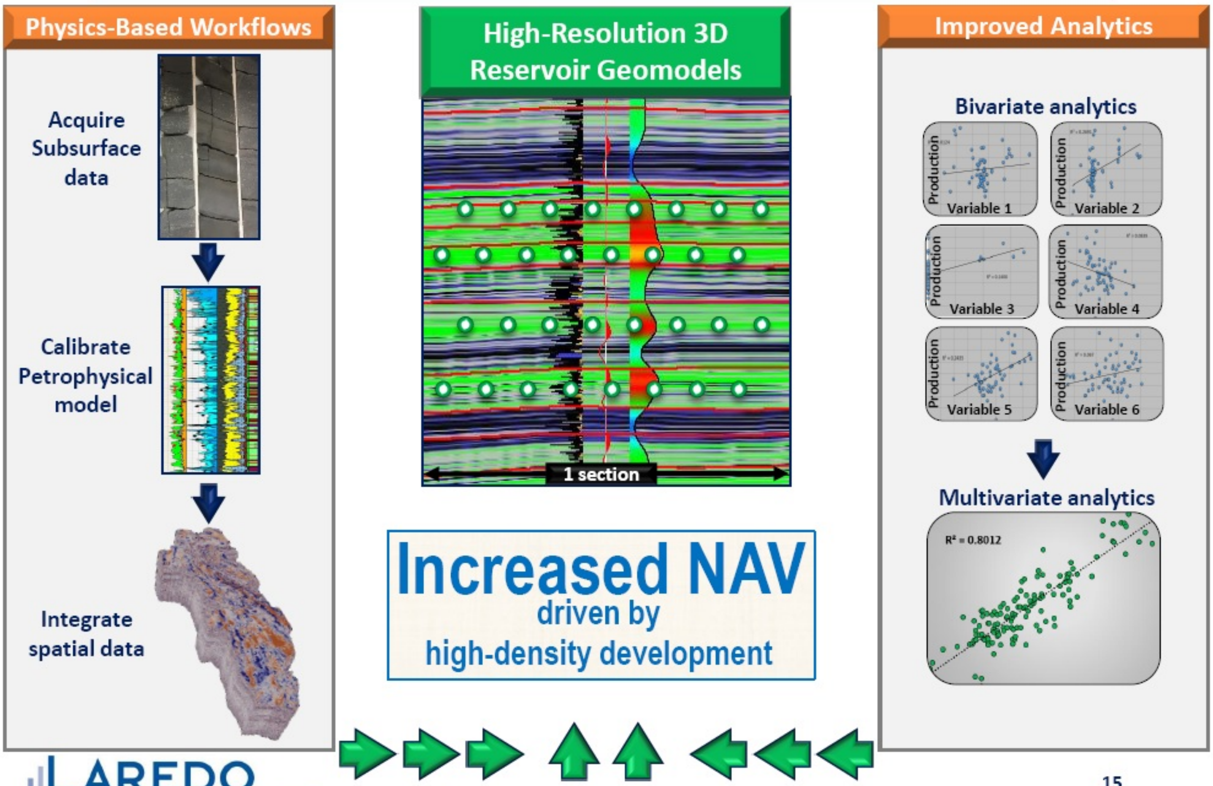
Infrastructure Helping to Deliver Peer-Leading LOE



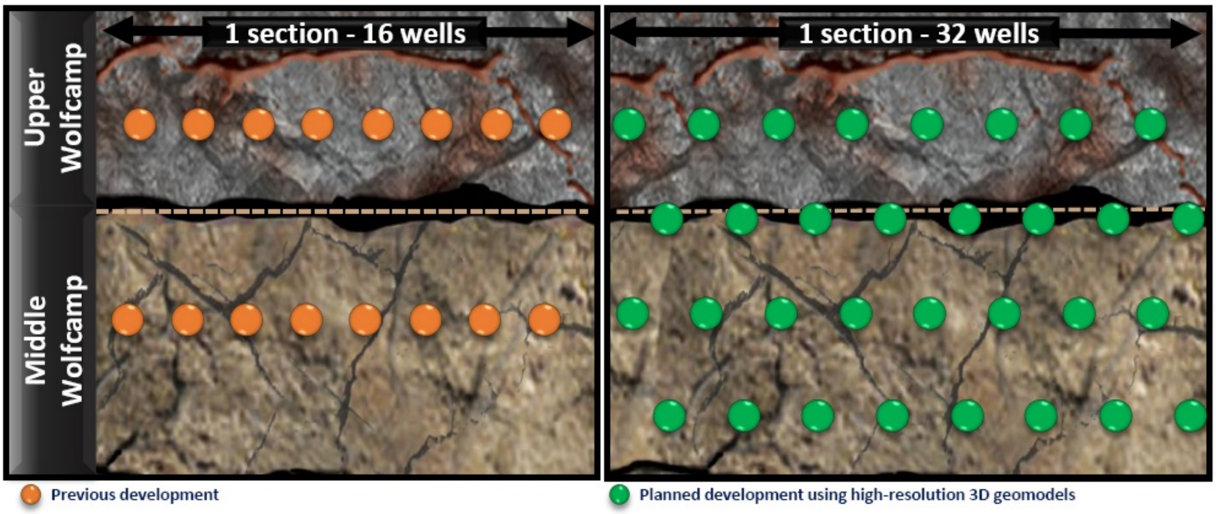
Gap between LPI unit LOE vs. peers has historically widened as more production is placed on infrastructure corridors

Note: Peers include CPE, CXO, EGN, FANG, PE, PXD & RSPP

Advanced Subsurface Characterization Drives Optimized Development



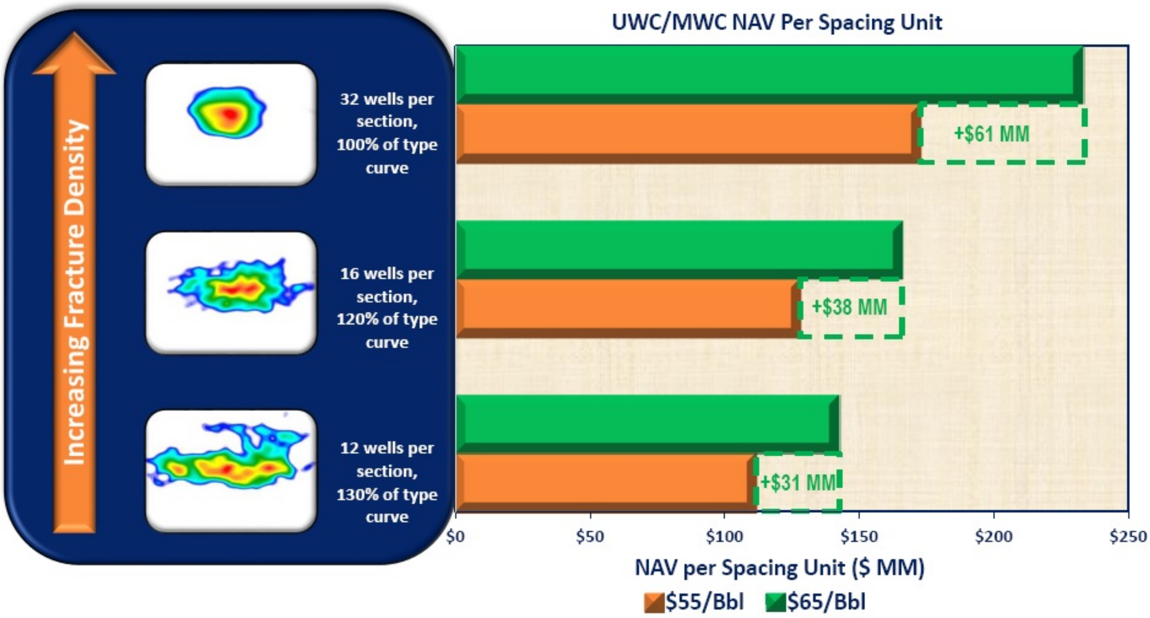
Transitioning to Higher-Density Development



32 locations per section Results of 2017 spacing tests suggest development possibility of up to 32 UWC/MWC locations per spacing unit

Note: Diagrams are not to scale
Spacing unit comprised of two sections to accommodate 10,000' laterals

Tighter Cluster Spacing Facilitates Higher-Density Development

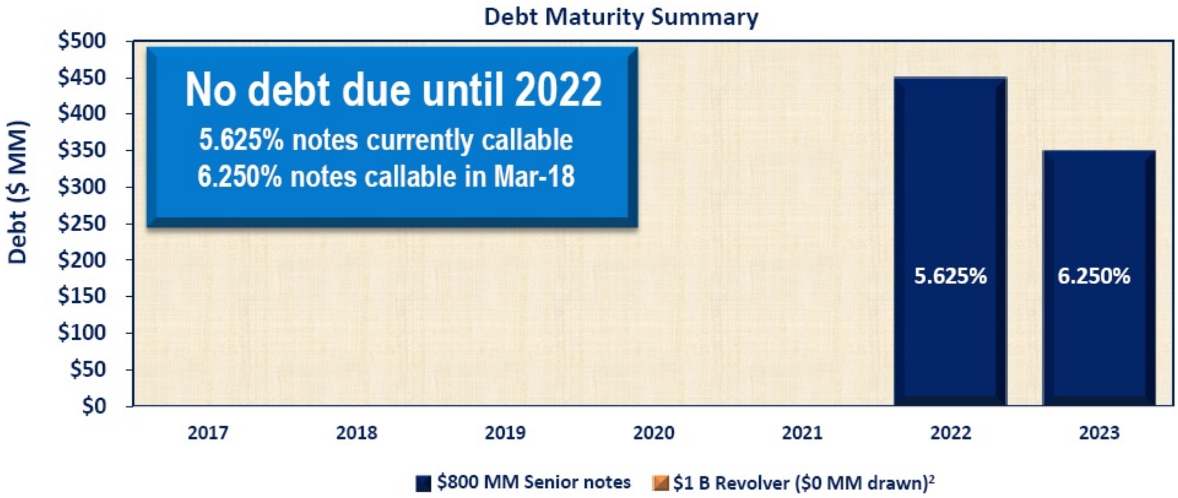


Tighter well density increases sensitivity to higher oil price

Note: NAV calculation pricing reflective of WTI benchmark, utilizing $3/Mcf flat HH benchmark and $7.1 MM D&C well cost
Spacing unit comprised of two sections to accommodate 10,000' laterals

Maintaining A Strong Balance Sheet

~1.3x net debt to Adjusted EBITDA[1]



[1] Net debt to Adjusted EBITDA includes net debt as of 12/31/17 and 4Q-17 annualized Adjusted EBITDA. Net debt is calculated as the face value of long-term debt of $800 MM, reduced by cash on hand of $112 MM

[2] As of 2/13/18, with $1 B Borrowing Base in place under Fifth Amended and Restated Senior Secured Credit Facility

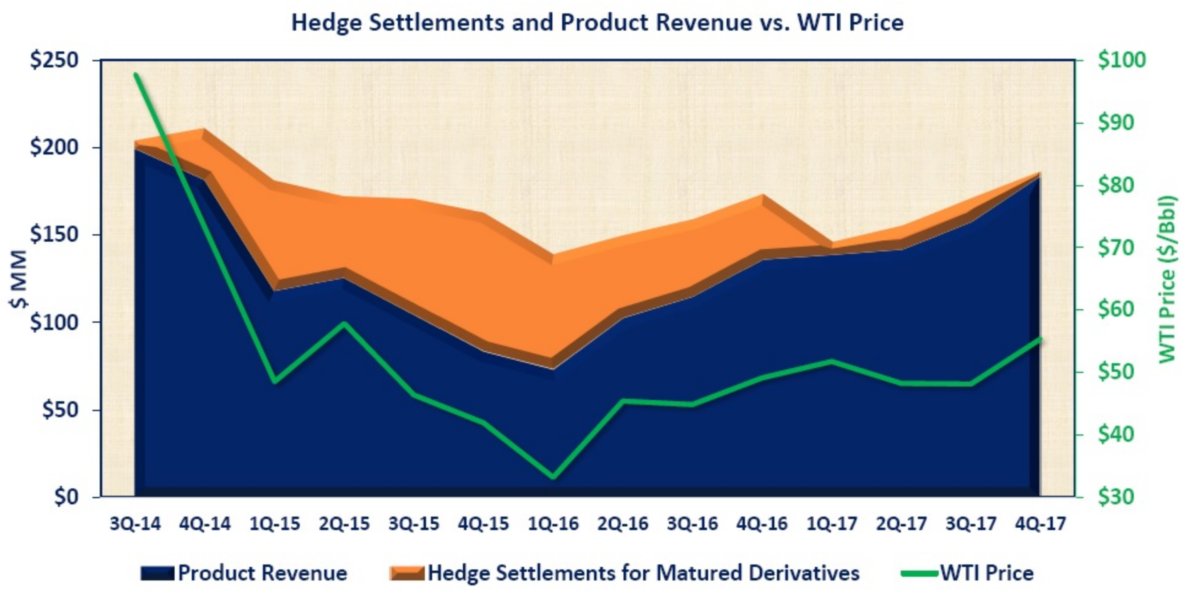
Stock Repurchase Program

- **Up to $200 MM stock repurchase approved**
  - **~10% reduction in current common stock outstanding[1,2]**
- **Plan to utilize cash on hand and senior secured credit facility**
  - **Results in ~1.7x net debt to Adjusted EBITDA post repurchase[2,3]**
- **Program authorized for two years by Board of Directors**

Stock repurchase program represents a highly accretive use of capital

[1] Assumes market prices as of 02/13/18
[2] Assumes all $200 MM utilized for stock repurchase
[3] Net debt to Adjusted EBITDA includes net debt as of 12/31/17 and 4Q-17 annualized Adjusted EBITDA. Net debt is calculated as the face value of long-term debt of $800 MM, reduced by cash on hand of $112 MM

Disciplined Risk Management Philosophy Protects Long-Term Value



Hedges provide cash flow stability during volatile pricing

Positioned for the Future

APPENDIX

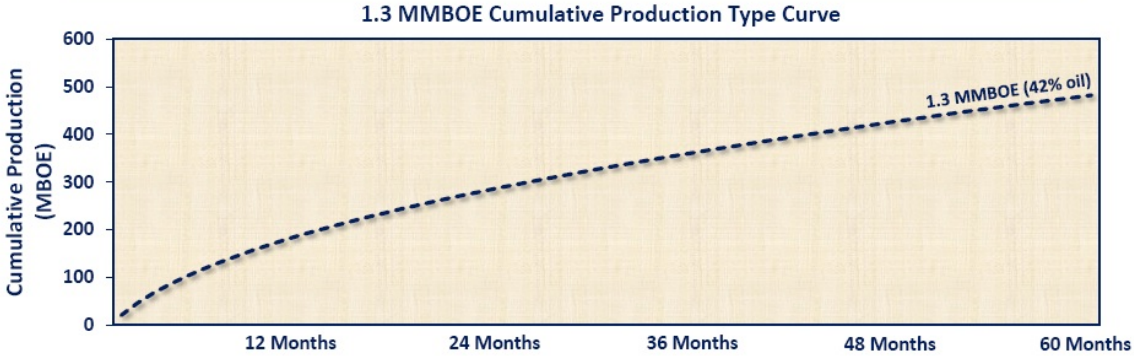
1Q-18E Guidance

	1Q-18E
Production (MBOE/d)........	62.0
Crude oil production (MBbl/d)........	27.0
Price Realizations (pre-hedge):	
Crude oil (% of WTI)........	97%
Natural gas liquids (% of WTI)........	28%
Natural gas (% of Henry Hub)........	57%
Operating Costs & Expenses:	
Lease operating expenses ($/BOE)........	$3.55
Midstream expenses ($/BOE)........	$0.20
Production and ad valorem taxes (% of oil, NGL and natural gas revenue)....	6.25%
General and administrative expenses:	
Cash ($/BOE)........	$2.90
Non-cash stock-based compensation[1] ($/BOE)........	$1.65
Depletion, depreciation and amortization ($/BOE)........	$7.75

[1]Net of amounts capitalized

Note: Crude oil price realizations reflect a pricing election made in accordance with the terms of a crude oil purchase agreement with Shell Trading (US) Company ("Shell"). However, the pricing terms under the crude oil purchase agreement are the subject of litigation filed against the Company by Shell. The Company believes it has substantive defenses and intends to vigorously defend its position. Please see Note 11.a. in the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2017 and Note 13.b. in the Company's Annual Report on Form 10-K for the year ended December 31, 2017 for more information regarding the litigation

UWC & MWC 1.3 MMBOE Cumulative Production Type Curve



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

45%
Total oil recovered in the first five years

Note: 10,000' lateral length with 1,800 pounds of sand per foot completions at 54' perf cluster spacing

Oil, Natural Gas & Natural Gas Liquids Hedges

Hedge Product Summary	FY-18	FY-19	FY-20
Oil total floor volume (Bbl)	9,515,375	6,606,500	1,061,400
Oil wtd-avg floor price ($/Bbl)	$47.42	$48.82	$49.70
Nat gas total floor volume (MMBtu)	23,805,500		
Nat gas wtd-avg floor price ($/MMBtu)	$2.50		
NGL total floor volume (Bbl)	1,436,200		

Oil	FY-18	FY-19	FY-20
Puts			
Hedged volume (Bbl)	5,427,375	5,949,500	366,000
Wtd-avg floor price ($/Bbl)	$51.93	$48.31	$45.00
Swaps			
Hedged volume (Bbl)		657,000	695,400
Wtd-avg price ($/Bbl)		$53.45	$52.18
Collars			
Hedged volume (Bbl)	4,088,000		
Wtd-avg floor price ($/Bbl)	$41.43		
Wtd-avg ceiling price ($/Bbl)	$60.00		

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

Natural Gas Liquids	FY-18	FY-19	FY-20
Swaps - Ethane:			
Hedged volume (Bbl)	567,800		
Wtd-avg price ($/Bbl)	$11.66		
Swaps - Propane:			
Hedged volume (Bbl)	467,600		
Wtd-avg price ($/Bbl)	$33.92		
Swaps – Normal Butane:			
Hedged volume (Bbl)	167,000		
Wtd-avg price ($/Bbl)	$38.22		
Swaps - Isobutane:			
Hedged volume (Bbl)	66,800		
Wtd-avg price ($/Bbl)	$38.33		
Swaps - Natural Gasoline:			
Hedged volume (Bbl)	167,000		
Wtd-avg price ($/Bbl)	57.02		

Note: Natural gas liquids derivatives are for February through December 2018 and are settled based on the month's average daily OPIS index price for Mt. Belvieu Purity Ethane and Non-TET: Propane, Normal Butane, Isobutane and natural gasoline

Basis Swaps	FY-18	FY-19	FY-20
Mid/Cush Basis Swaps			
Hedged volume (Bbl)	3,650,000		
Wtd-avg price ($/Bbl)	-$0.56		
HH/WAHA Basis Swaps			
Hedged volume (MMBtu)	9,125,000	9,125,000	
Wtd-avg price ($/MMBtu)	-$0.62	-$0.70	

Note: Oil basis swaps are settled based on the West Texas Intermediate Midland weighted average price published in Argus Americas Crude and the West Texas Intermediate Cushing Formula Basis price published in Argus Americas Crude. Natural gas basis swaps are settled based on the inside FERC index price for West Texas WAHA and NYMEX Henry Hub

Natural Gas - WAHA	FY-18	FY-19	FY-20
Puts			
Hedged volume (MMBtu)	8,220,000		
Wtd-avg floor price ($/MMBtu)	$2.50		
Collars			
Hedged volume (MMBtu)	15,585,500		
Wtd-avg floor price ($/MMBtu)	$2.50		
Wtd-avg ceiling price ($/MMBtu)	$3.35		

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

2017 Actuals

		1Q-17	2Q-17	3Q-17	4Q-17	FY-17
Sales Volumes	**3-Stream Sales Volumes**					
	MBOE	4,716	5,336	5,521	5,697	21,270
	BOE/d	52,405	58,632	60,011	61,922	58,273
	% oil	45%	47%	44%	43%	45%
Pricing	**3-Stream Realized Prices**					
	Oil ($/Bbl)	$46.91	$42.00	$45.44	$53.57	$46.97
	NGL ($/Bbl)	$16.49	$13.82	$18.58	$20.53	$17.49
	Gas ($/Mcf)	$2.31	$2.09	$2.04	$1.95	$2.09
	Avg. price ($/BOE)	$29.42	$26.58	$28.54	$32.19	$29.22
Unit Cost Metrics	**3-Stream Unit Cost Metrics ($/BOE)**					
	Lease operating expenses	$3.60	$3.77	$3.55	$3.22	$3.53
	Midstream	$0.19	$0.17	$0.21	$0.20	$0.19
	Production & ad val taxes	$1.86	$1.59	$1.73	$1.93	$1.78
	General & administrative					
	Cash	$3.47	$2.50	$2.90	$2.61	$2.85
	Non-cash stock-based compensation[1]	$1.96	$1.63	$1.62	$1.55	$1.68
	DD&A	$7.23	$7.12	$7.46	$7.91	$7.45

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[1]Net of amounts capitalized

2015 & 2016 Actuals

		1Q-15	2Q-15	3Q-15	4Q-15	FY-15	1Q-16	2Q-16	3Q-16	4Q-16	FY-16
Sales Volumes	3-Stream Sales Volumes										
	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%
Pricing	3-Stream Realized Prices										
	Oil ($/Bbl)	$41.73	$50.77	$42.88	$36.97	$43.27	$27.51	$39.37	$39.10	$43.98	$37.73
	NGL ($/Bbl)	$13.34	$12.85	$10.36	$11.06	$11.86	$8.50	$12.24	$11.54	$14.79	$11.91
	Gas ($/Mcf)	$2.14	$1.82	$2.01	$1.76	$1.93	$1.31	$1.31	$2.07	$2.13	$1.73
	Avg. price ($/BOE)	$27.64	$29.65	$25.37	$22.47	$26.41	$17.40	$23.64	$24.34	$27.82	$23.50
Unit Cost Metrics	3-Stream Unit Cost Metrics ($/BOE)										
	Lease operating expenses	$7.58	$6.90	$6.09	$5.83	$6.63	$4.88	$4.43	$3.85	$3.56	$4.15
	Midstream	$0.37	$0.38	$0.26	$0.43	$0.36	$0.14	$0.27	$0.22	$0.26	$0.22
	Production & ad val taxes	$2.13	$2.24	$1.91	$1.73	$2.01	$1.53	$1.84	$1.50	$1.45	$1.58
	General & administrative										
	Cash	$3.99	$4.00	$3.89	$4.27	$4.03	$3.72	$3.33	$3.49	$3.28	$3.45
	Non-cash stock-based compensation[1]	$1.12	$1.48	$1.67	$1.77	$1.50	$0.91	$1.40	$2.05	$1.98	$1.61
	DD&A	$16.83	$17.03	$16.19	$18.01	$16.99	$9.87	$7.88	$7.45	$7.68	$8.17

[1]Net of amounts capitalized

2014 Actuals: Two-Stream to Three-Stream Conversions

		1Q-14	2Q-14	3Q-14	4Q-14	FY-14
Sales Volumes	**2-Stream Sales Volumes**					
	MBOE	2,434	2,607	3,033	3,654	11,729
	BOE/d	27,041	28,653	32,970	39,722	32,134
	% oil	58%	58%	59%	60%	59%
	3-Stream Sales Volumes					
	MBOE	2,912	3,078	3,569	4,267	13,827
	BOE/d	32,358	33,829	38,798	46,379	37,882
	% oil	49%	49%	50%	51%	50%
Pricing	**2-Stream Realized Prices**					
	Oil ($/Bbl)	$91.78	$94.47	$87.65	$65.05	$82.83
	Gas ($/Mcf)	$7.04	$6.08	$5.80	$4.46	$5.72
	Avg. Price ($/BOE)	$71.17	$70.13	$65.77	$49.70	$62.86
	3-Stream Realized Prices					
	Oil ($/Bbl)	$91.78	$94.47	$87.65	$65.05	$82.83
	NGL ($/Bbl)	$32.88	$28.79	$29.21	$19.65	$27.00
	Gas ($/Mcf)	$4.00	$3.73	$3.25	$3.00	$3.45
	Avg. Price ($/BOE)	$59.48	$59.40	$55.89	$42.57	$53.32
Unit Cost Metrics	**2-Stream Unit Cost Metrics ($/BOE)**					
	Lease operating expenses	$8.95	$7.74	$8.30	$8.04	$8.23
	Midstream	$0.35	$0.59	$0.40	$0.50	$0.46
	Production & ad valorem taxes	$5.12	$5.05	$4.14	$3.33	$4.29
	General & administrative					
	Cash	$9.58	$8.88	$6.89	$4.27	$7.07
	Non-cash stock-based compensation[1]	$1.78	$2.45	$2.04	$1.69	$1.97
	DD&A	$20.38	$20.35	$21.08	$21.85	$21.01
	3-Stream Unit Cost Metrics ($/BOE)					
	Lease operating expenses	$7.48	$6.55	$7.05	$6.88	$6.98
	Midstream	$0.29	$0.50	$0.34	$0.43	$0.39
	Production & ad valorem taxes	$4.28	$4.27	$3.52	$2.85	$3.64
	General & Administrative					
	Cash	$8.01	$7.52	$5.85	$3.66	$6.00
	Non-cash stock-based compensation[1]	$1.49	$2.08	$1.74	$1.44	$1.67
	DD&A	$17.03	$17.23	$17.91	$18.72	$17.83

[1]Net of amounts capitalized

Note: 2014 2-stream to 3-stream conversion based on actual gas plant economics

Supplemental Non-GAAP Financial Measure

Proved Developed Finding and Development Cost (Unaudited)

Proved developed finding and development ("F&D") cost per BOE 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 does 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.

($ MM, except per BOE amount, reserves and sales volumes in MMBOE)	Proved Developed F&D
Development costs (x)	$561
Proved developed reserves:	
As of December 31, 2017	191
As of December 31, 2016	(141)
Change in proved developed reserves	50
Plus sales of proved developed reserves during 2017	-
Plus 2017 sales volumes	21
Proved developed reserve additions (y)	71
Proved developed F&D cost per BOE	$7.90

Supplemental Non-GAAP Financial Measure

Adjusted EBITDA

Adjusted EBITDA is a non-GAAP financial measure that we define as net income or loss plus adjustments for income tax expense or benefit, depletion, depreciation & amortization, bad debt expense, impairment expense, non-cash stock-based compensation, net of amounts capitalized, accretion expense, mark-to-market on derivatives, cash premiums paid for derivatives, interest expense, write-off of debt issuance costs, gains or losses on disposal of assets, income or loss from equity method investee, proportionate Adjusted EBITDA of our equity method investee & other non-recurring income & expenses. Adjusted EBITDA provides no information regarding a company's capital structure, borrowings, interest costs, capital expenditures, working capital movement or tax position. Adjusted EBITDA does not represent funds available for discretionary use because those funds are required for debt service, capital expenditures, working capital, income taxes, franchise taxes & other commitments & 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 & natural gas industry to measure a company's operating performance without regard to items excluded from the calculation of such term, which can vary substantially from company to company depending upon accounting methods, the book value of assets, capital structure & the method by which assets were acquired, among other factors;
- helps investors to more meaningfully evaluate & 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 & as a basis for strategic planning & 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 & non-recurring items that materially affect our net income or loss, the lack of comparability of results of operations to different companies & 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.

Supplemental Non-GAAP Financial Measure

Adjusted EBITDA

(in thousands)		4Q-16		4Q-17
Net income	$	(18,421)	$	408,561
Plus:				
Income tax expense		-		1,800
Depletion, depreciation and amortization		37,526		45,062
Non-cash stock-based compensation, net of amounts capitalized		9,667		8,857
Accretion of asset retirement obligations		896		969
Mark-to-market on derivatives:				
(Gain) loss on derivatives, net		43,642		37,777
Cash settlements received for matured derivatives, net		37,655		2,792
Cash settlements received for early termination derivatives, net		-		80,000
Cash premiums paid for derivatives		(2,697)		(12,311)
Interest expense		23,004		19,787
Gain on sale of investment in equity method investee**		-		(405,906)
Loss on disposal of assets, net		411		906
Income from equity method investee**		(3,144)		(575)
Proportionate Adjusted EBITDA of equity method investee**		6,386[1]		2,326[1**]
Adjusted EBITDA	$	134,925	$	133,806

[1]Medallion Adjusted EBITDA *(in thousands)*		4Q-16		4Q-17
Income from equity method investee	$	3,144	$	575
Adjusted for proportionate share of:				
Depreciation and amortization		3,242		1,751
Proportionate Adjusted EBITDA of equity method investee	$	6,386	$	2,326

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