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): September 6, 2017

LAREDO PETROLEUM, INC.

(Exact name of registrant as specified in charter)

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

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

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

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

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

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

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

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

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

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

Emerging Growth Company o

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

Item 7.01. Regulation FD Disclosure.

Laredo Petroleum, Inc.'s (the "Company") Chairman and Chief Executive Officer, Randy A. Foutch, is scheduled to present at Barclays' CEO Energy-Power conference on September 7, 2017 in New York City, New York. On September 6, 2017, the Company posted to its website the presentation it will utilize during the conference (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 in this Item 7.01 by reference. Page 21 of the Presentation includes revised guidance for the third quarter of 2017.

All statements in this Item 7.01, the Presentation and any oral statements made during the conference, 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, 2016 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 September 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.

Dated: September 6, 2017	By:	/s/ Richard C. Buterbaugh
		Richard C. Buterbaugh
		Executive Vice President and Chief Financial Officer

EXHIBIT INDEX

Exhibit Number	Description
99.1	Corporate Presentation September 2017.

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

Corporate Presentation
September 2017

LAREDO PETROLEUM

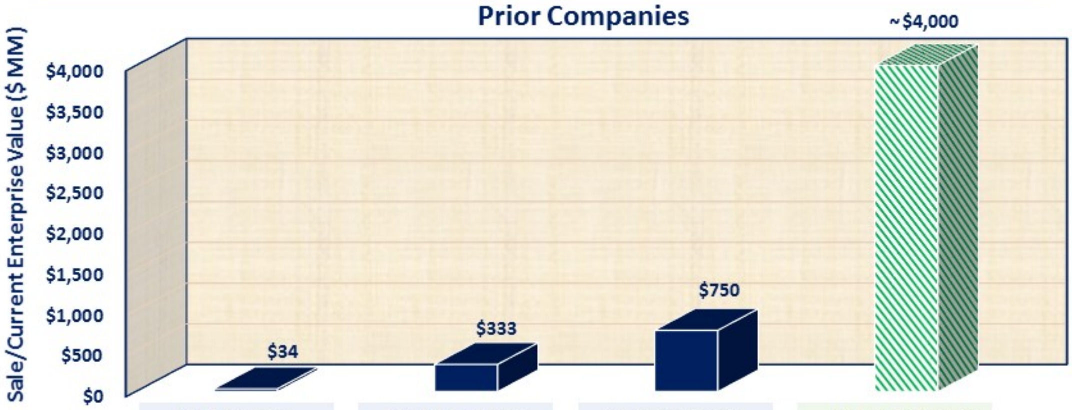
Forward-Looking / Cautionary Statements

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, successful results from the Company's identified drilling locations, the Company's ability to replace reserves and efficiently develop and exploit its current reserves and other important factors that could cause actual results to differ materially from those projected as described in the Company's Annual Report on Form 10-K for the year ended December 31, 2016 and other reports filed with the Securities Exchange Commission ("SEC").

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

The SEC generally permits oil and natural gas companies to disclose proved reserves in filings made with the SEC, which are reserve estimates that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions and certain probable and possible reserves that meet the SEC's definitions for such terms. In this presentation, the Company may use the terms "unproved reserves," "resource potential," "estimated ultimate recovery," "EUR," "development ready," "horizontal productivity confirmed," "horizontal productivity not confirmed" or other descriptions of potential reserves or volumes of reserves which the SEC guidelines restrict from being included in filings with the SEC without strict compliance with SEC definitions. "Unproved reserves" refers to the Company's internal estimates of hydrocarbon quantities that may be potentially discovered through exploratory drilling or recovered with additional drilling or recovery techniques. "Resource potential" is used by the Company to refer to the estimated quantities of hydrocarbons that may be added to proved reserves, largely from a specified resource play potentially supporting numerous drilling locations. A "resource play" is a term used by the Company to describe an accumulation of hydrocarbons known to exist over a large areal expanse and/or thick vertical section potentially supporting numerous drilling locations, which, when compared to a conventional play, typically has a lower geological and/or commercial development risk. The Company does not choose to include unproved reserve estimates in its filings with the SEC. "Estimated ultimate recovery", or "EUR", refers to the Company's internal estimates of per-well hydrocarbon quantities that may be potentially recovered from a hypothetical and/or actual well completed in the area. Actual quantities that may be ultimately recovered from the Company's interests are unknown. Factors affecting ultimate recovery include the scope of the Company's ongoing drilling program, which will be directly affected by the availability of capital, drilling and production costs, availability and cost of drilling services and equipment, lease expirations, transportation constraints, regulatory approvals and other factors, as well as actual drilling results, including geological and mechanical factors affecting recovery rates. Estimates of ultimate recovery from reserves may change significantly as development of the Company's core assets provide additional data. In addition, the Company's production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases.

Management's Established Track Record of Creating Value Continues

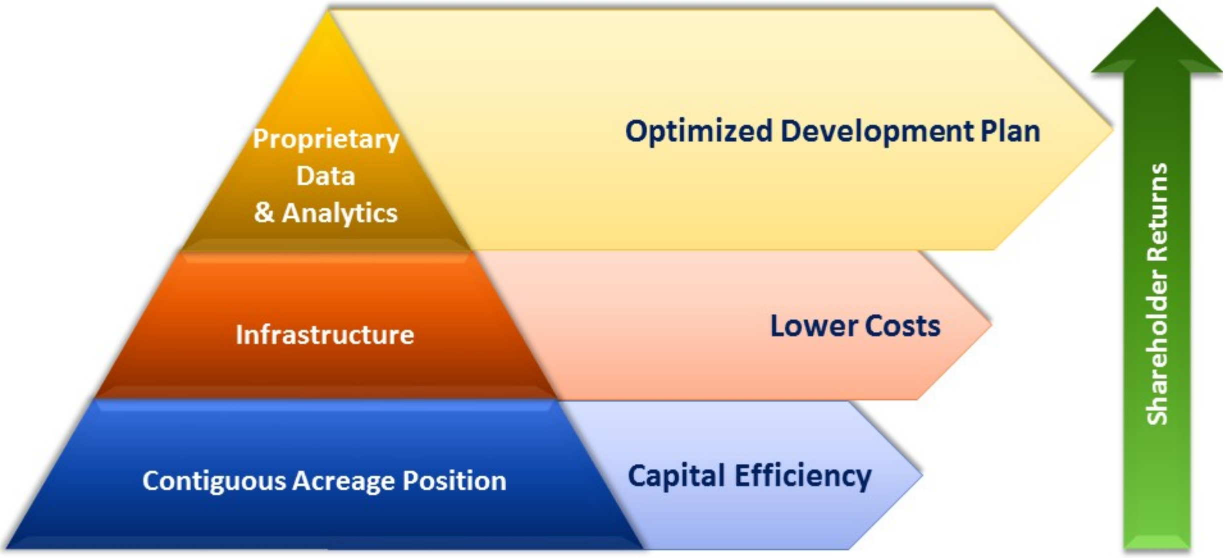


	Colt Resources	Lariat Petroleum	Latigo Petroleum	Laredo Petroleum [1]
Time	1991 - 1996	1997 - 2001	2002 - 2006	Est. 2006
Partners	First Reserve	Warburg Pincus	Warburg Pincus & JPM	Warburg Pincus & Public
Buyer	JN Resources	Newfield Exploration	Pogo Producing	Publicly traded

>$5 B Total value of companies founded by Mr. Foutch, each guided by the same common, consistent strategies

[1] Enterprise value as of 06/30/17

Steady, Strategic Plan Yields Repeatable Results



A disciplined focus on key value drivers since inception has driven shareholder returns

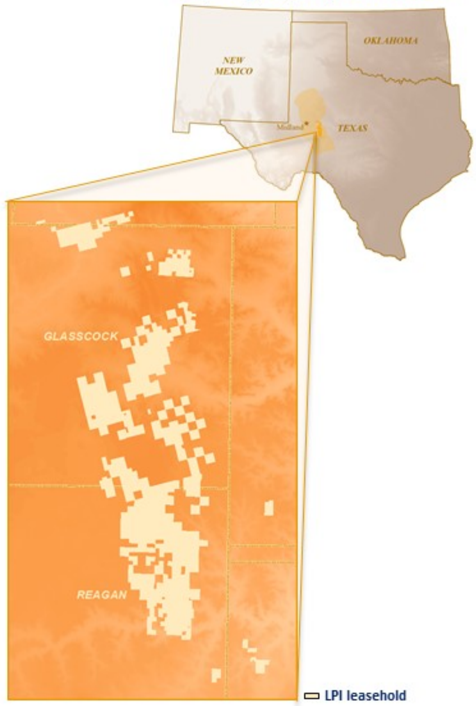
Capitalizing on Our Contiguous Acreage Position

- **The Company has identified >2,000 locations from its total inventory that support lateral lengths of 10,000'+ on its contiguous acreage**

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

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

145,499 gross/125,967 net acres



Note: Acreage counts as of 6/30/17

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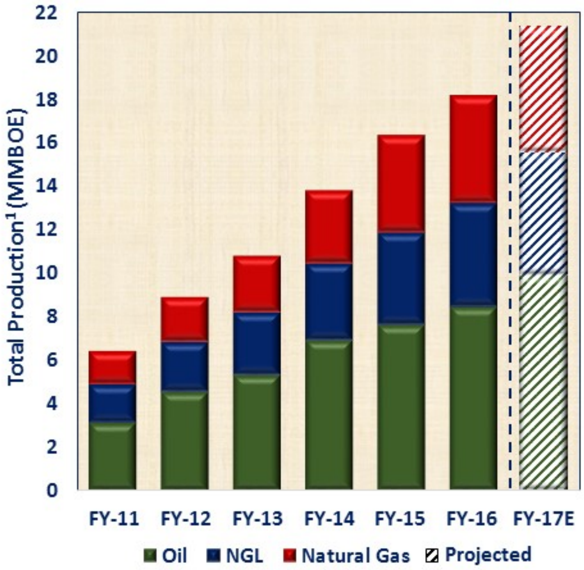
Consistent Growth Despite Commodity Price Decline



16% - 19%
2017E YoY Production Growth

$5.12/BOE
2016's PD F&D rate

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[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. 2017 estimated production is utilizing the midpoint of 16% - 19% of production guidance

[2] 38 MMBOE of Ye-15 PD revisions were attributable to the year-over-year crude oil price drop

Contiguous Acreage Facilitated Robust Infrastructure Investments

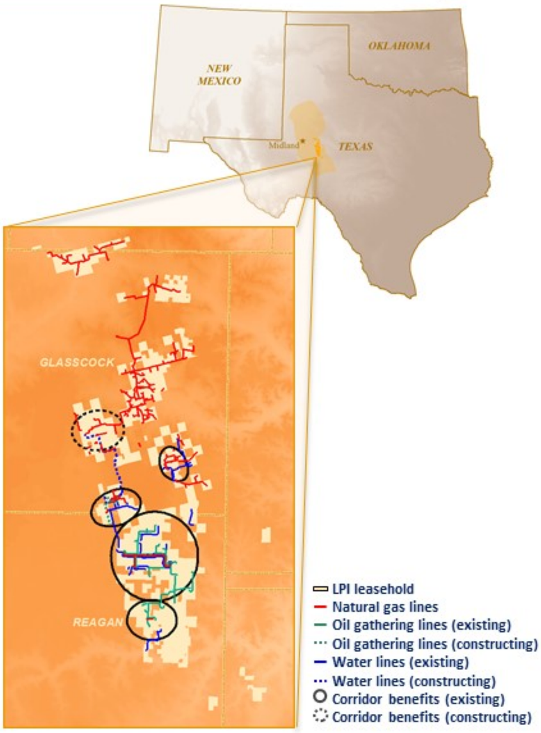
PIPELINE INFRASTRUCTURE

~45 Miles
CRUDE GATHERING

~80 Miles
WATER GATHERING / RECYCLED DISTRIBUTION

~188 Miles
NATURAL GAS GATHERING & DISTRIBUTION

>165,000
Truckloads removed from roads in 2017E due to LMS' water and crude gathering infrastructure



Prior Investments in Infrastructure Provide Tangible Benefits

Yield capital & LOE savings, plus increased revenues & 3rd party income
Enable multi-well pad drilling & operational flexibility
Minimize trucking

LMS Corridor Benefit	LPI Benefit	2016 Benefits Actual ($ MM)	2017 Benefits Estimated ($ MM)
Crude gathering	Increased revenues & 3rd-party income	$10.4	$13.3
Centralized gas lift	LOE savings	$0.9	$1.0
Completions utilizing recycled water	Capital savings	$1.1	$2.0
Produced water recycled	Capital & LOE savings	$2.0	$2.1
Produced water gathered on pipe	Capital & LOE savings	$9.6	$9.9
Corridor Benefits Total		$24.1	$28.4


Water Treatment Plant


Centralized Crude Gathering Tanks at Reagan Truck Station


Centralized Natural Gas Compressor

Note: Benefits as of 7/27/17. Totals may not foot due to rounding
Benefits defined as capital savings, LOE savings, price uplift and LMS net operating income

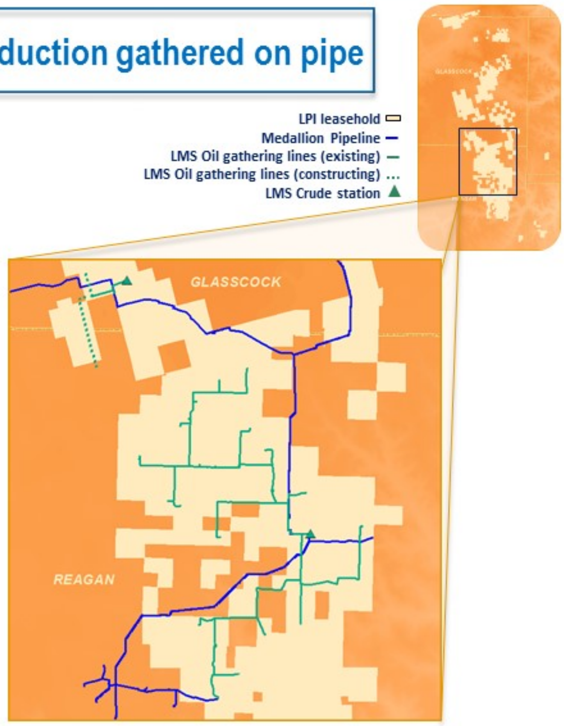
LMS Crude Gathering System Benefits

84% FY-17E gross operated 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 3rd-party income



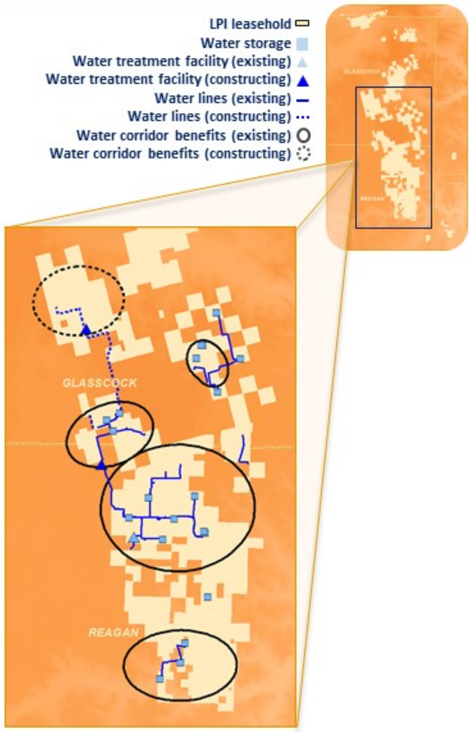
Note: As of 7/27/17

Significant Benefits through Water Infrastructure Investments

~10 MMBW
FY-17E produced water recycled

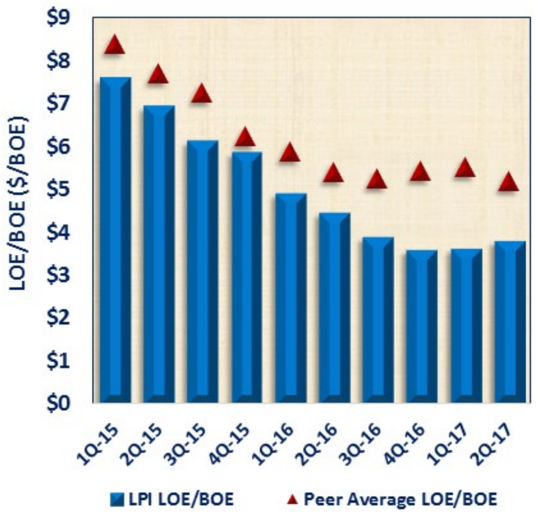
LMS Corridor Benefit	Completions Utilizing Recycled Water	Produced Water Recycled	Produced Water Gathered on Pipe
LPI Benefit	Capital savings	Capital & LOE savings	Capital & LOE savings
YE-17E (% of Total Activity)	~30%	~60%	~80%
Capacity	54 MBWPD Recycling Processing[1] & ~15.7 MMBW Storage Capacity		

>$4.9 MM
1H-17 LOE corridor benefits generated by LMS' water infrastructure



[1] Upon completion of two additional water treatment plants that are currently under construction
Note: As of 7/27/17

Infrastructure Helping to Deliver Peer-Leading LOE



10 Quarters
Consistent per-unit LOE outperformance

~$54 MM
Cumulative LOE savings versus peers

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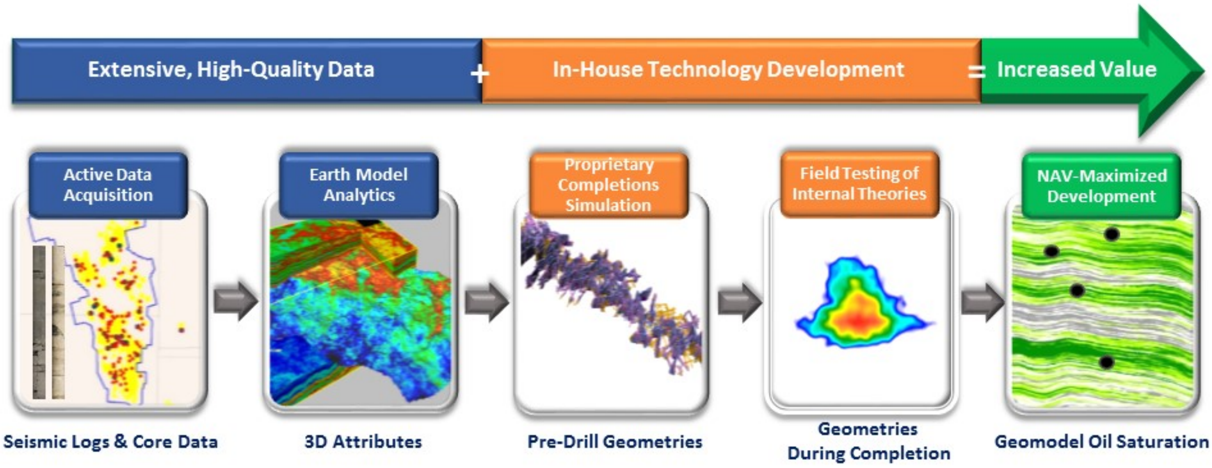
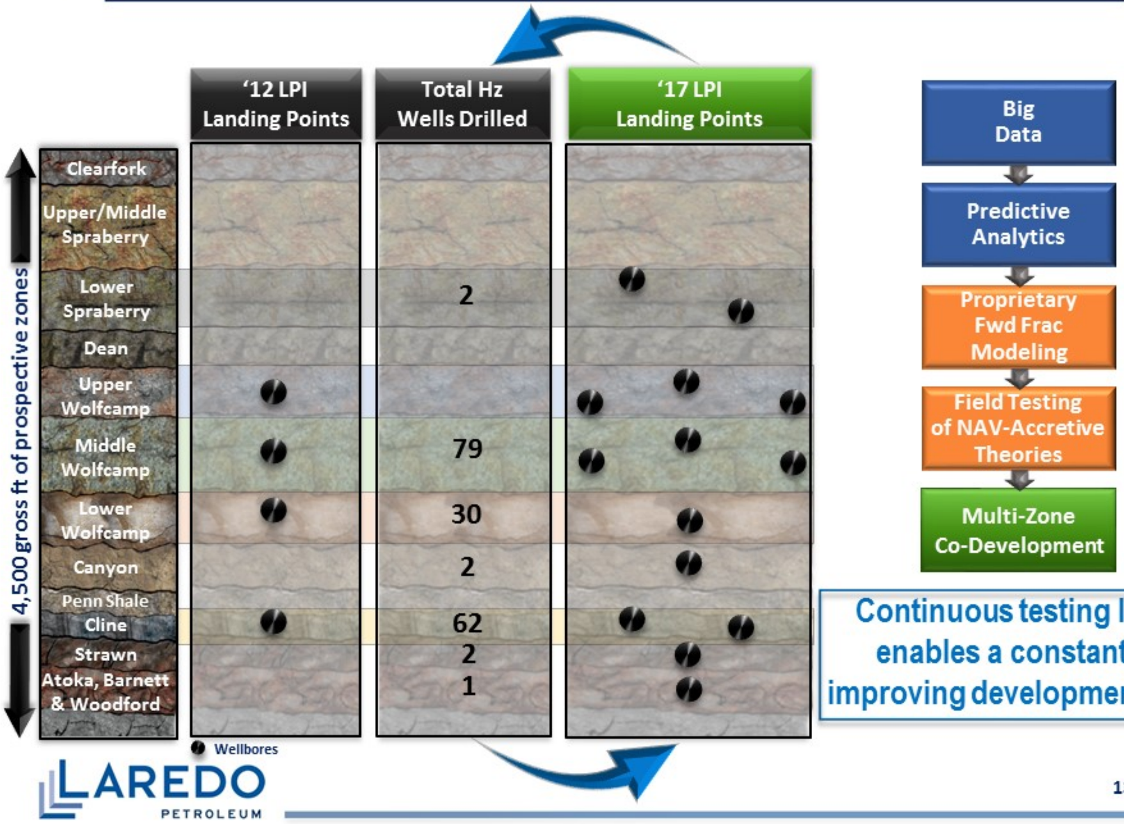
Note: Peers include CPE, CXO, EGN, FANG, PE, PXD & RSPP
Cumulative LOE $ savings utilizes the peer average LOE/BOE multiplied by LPI's actual production

Proprietary Modeling Accelerates Value Creation



Proprietary data and workflows accelerate the process of advancing concepts to implementation

Strategic Testing Leading to High-Quality, Multi-Zone Co-Development



Continuous testing loop enables a constantly-improving development plan

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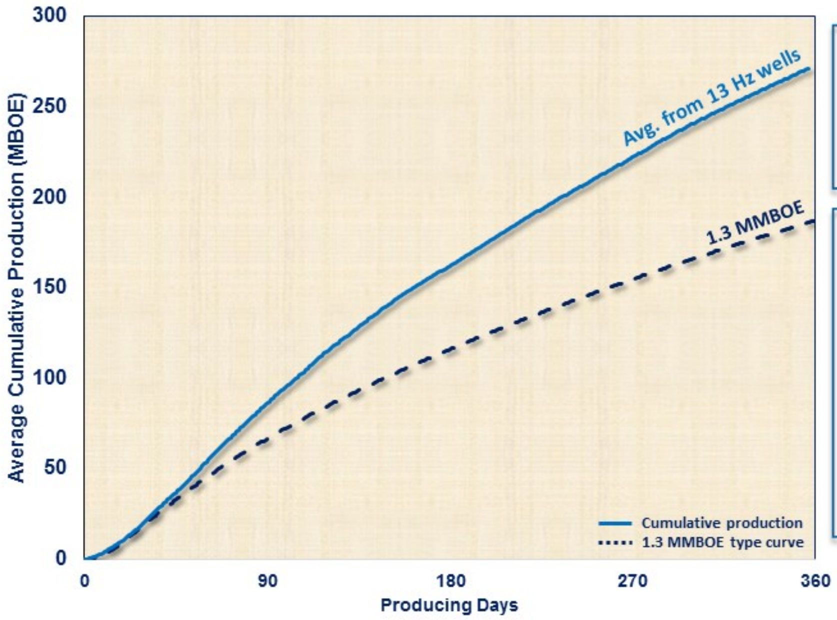
2,400 lb/ft Field Tests Confirm Internal Models



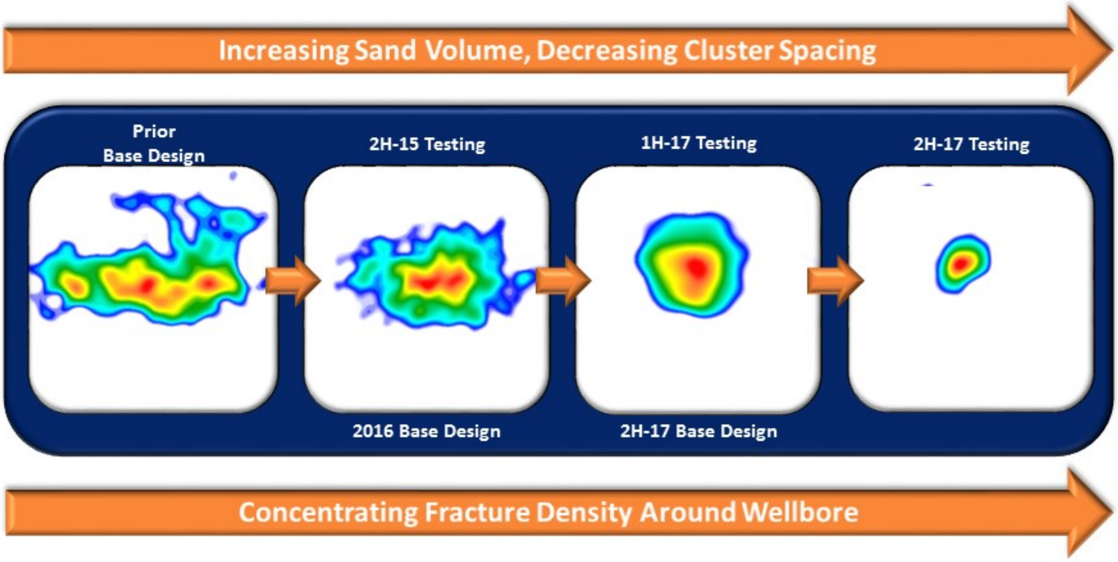
~46%
Outperformance to 1.3 MMBOE type curve

~50%
Pre-drill model uplift prediction when utilizing 2,400 lb/ft completions. Actual field tests are confirming our internal models

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

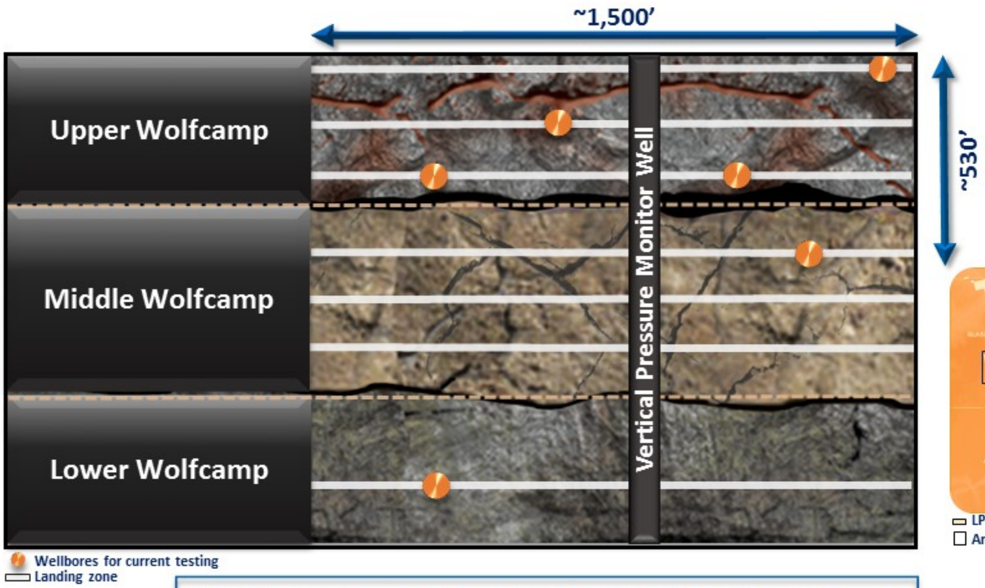
Internal Models Accelerate Completions Design Evolution

Proprietary workflows are shortening time from concept to field implementation, enabling continual optimization of completions designs



Testing Co-Development of Landing Points

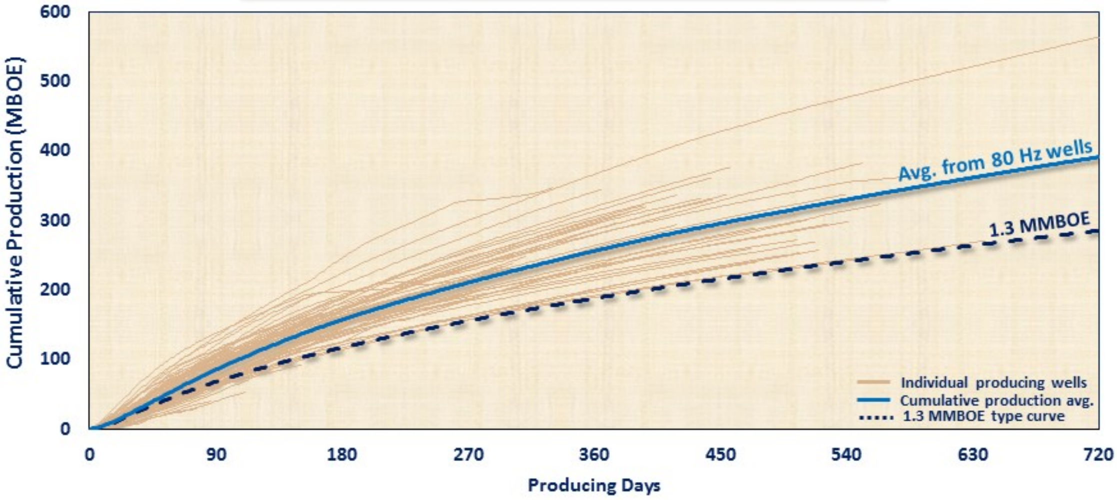
Potential to add additional high-value inventory in the UWC with current testing



Plan to apply spacing design to other formations, further increasing high-value inventory

Proprietary Workflows Deliver Well Productivity Improvements

~37%
Outperformance to 1.3 MMBOE type curve



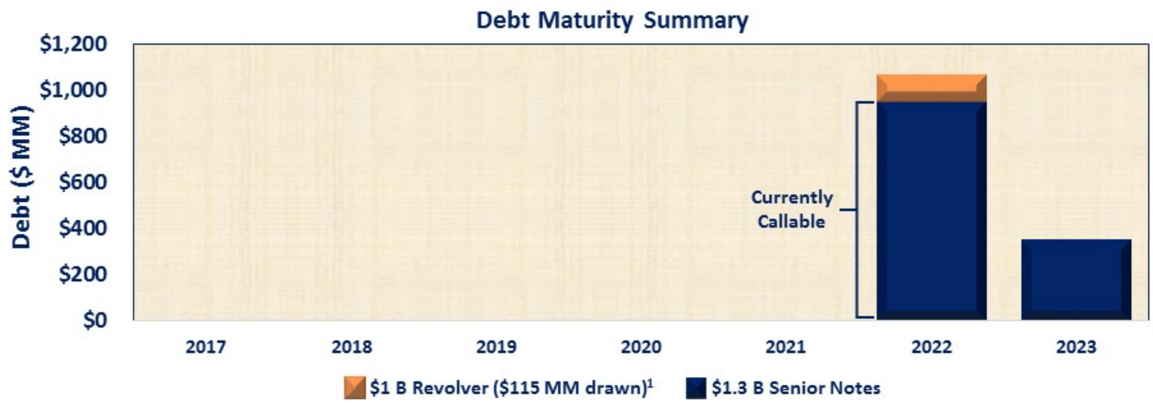
80 Wells Includes all wells that used proprietary models to optimize completions

Note: Production has been scaled to 10,000' EUR type curves and non-producing days (for shut-ins) have been removed
Average cumulative production data through 7/31/17. This includes 80 Hz UWC/MWC & Cline wells that have utilized optimized completions with avg. ~1,900 pounds of sand per lateral foot. Type curve utilizes a weighted-average of 77 Hz UWC/MWC 1.3 MMBOE wells & 3 Hz Cline 1.0 MMBOE wells

Maintaining Financial Flexibility

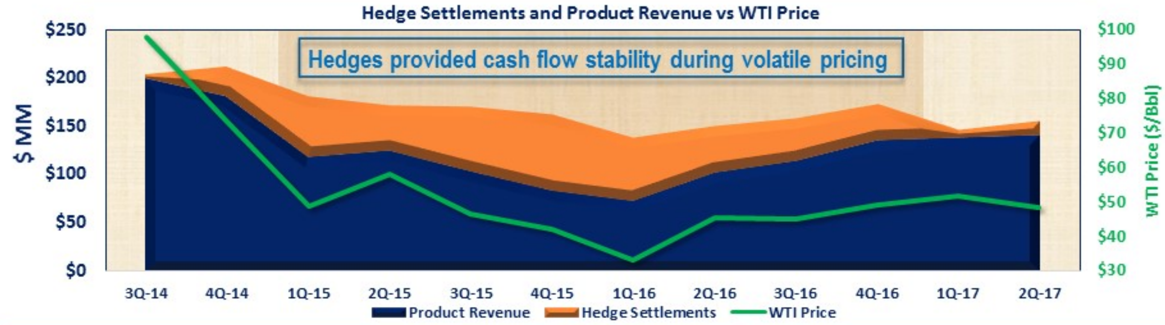
No debt due until 2022
$950 MM currently callable
+ $350 MM callable in 2018

$1,000 MM Revolver
$900 MM Liquidity



Note: As of 8/4/2017, with $1 B Borrowing Base in place under amended and restated Senior Secured Credit Facility. Liquidity includes cash on hand

Disciplined Risk Management Philosophy Insures Long-Term Value



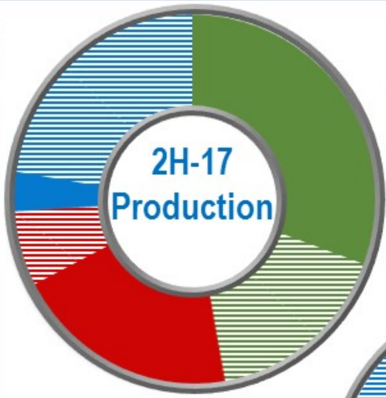
70%
Current cash margin exceeds pre-price decline cash margin[1]

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

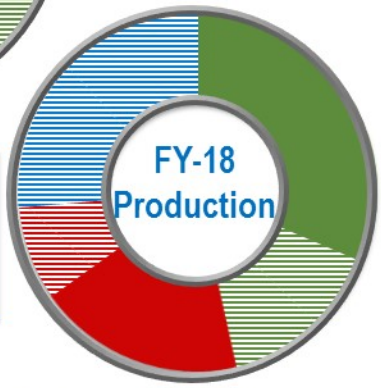
Note: 2014 cash margin has been converted to 3-stream using actual gas plant economics. Current cash margin percentage of realized pricing is as of 2Q-17

Oil, Natural Gas & Natural Gas Liquids Hedges

Hedge Totals	2H-17	FY-18
Oil total floor volume (Bbl)	3,454,600	6,704,875
Oil wtd-avg floor price ($/Bbl)	$55.82	$46.34
Nat gas total floor volume (MMBtu)	13,606,400	23,805,500
Nat gas wtd-avg floor price ($/MMBtu)	$2.75	$2.50
NGL total floor volume (Bbl)	409,500	
Oil[1]	**2H-17**	**FY-18**
Puts		
Hedged volume (Bbl)	529,000	2,616,875
Wtd-avg floor price ($/Bbl)	$60.00	$54.01
Swaps		
Hedged volume (Bbl)	1,012,000	
Wtd-avg price ($/Bbl)	$51.54	
Collars		
Hedged volume (Bbl)	1,913,000	4,088,000
Wtd-avg floor price ($/Bbl)	$56.92	$41.43
Wtd-avg ceiling price ($/Bbl)	$60.23	$60.00
Natural Gas[2]	**2H-17**	**FY-18**
Puts		
Hedged volume (MMBtu)	4,020,000	8,220,000
Wtd-avg floor price ($/MMBtu)	$2.50	$2.50
Collars		
Hedged volume (MMBtu)	9,586,400	15,585,500
Wtd-avg floor price ($/MMBtu)	$2.86	$2.50
Wtd-avg ceiling price ($/MMBtu)	$3.54	$3.35
Natural Gas Liquids[3]	**2H-17**	**FY-18**
Swaps - Ethane:		
Hedged volume (Bbl)	222,000	
Wtd-avg price ($/Bbl)	$11.24	
Swaps - Propane:		
Hedged volume (Bbl)	187,500	
Wtd-avg price ($/Bbl)	$22.26	



~65%
Bal-17 crude percentage floored



~68%
FY-18 crude percentage floored

Hedged Oil | Hedged Natural Gas | Hedged NGLs
Unhedged Oil | Unhedged Natural Gas | Unhedged NGLs

Note: Data as of 6/30/2017 & percentages hedged utilize actual 2016 production plus the midpoint of 16% - 19% growth for FY-17 and flat FY-17 production for FY-18

[1] 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

[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 average daily OPIS index price for Mt. Belvieu Purity Ethane and TET Propane

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3Q-17 and 4Q-17 Guidance

	3Q-17	4Q-17
Production (MBOE/d)	60 - 62	61 - 64
Product % of total production:		
Crude oil	44% - 46%	45% - 47%
Natural gas liquids	26% - 27%	*
Natural gas	27% - 28%	*
Price Realizations (pre-hedge):		
Crude oil (% of WTI)	~94%	*
Natural gas liquids (% of WTI)	~31%	*
Natural gas (% of Henry Hub)	~69%	*
Operating Costs & Expenses:		
Lease operating expenses ($/BOE)	$3.60 - $4.00	*
Midstream expenses ($/BOE)	$0.20 - $0.30	*
Production and ad valorem taxes (% of oil, NGL and natural gas revenue)	6.25%	*
General and administrative expenses[1]:		
Cash ($/BOE)	$2.50 - $3.00	*
Non-cash stock-based compensation ($/BOE)	$1.50 - $1.75	*
Depletion, depreciation and amortization ($/BOE)	$7.00 - $7.50	*

□ Revised from initial 3Q-17 guidance

[1] Net of amounts capitalized

*Will be provided in conjunction with 3Q-17 earnings release

Note: Initial guidance for crude oil price realizations for the third quarter of 2017 has been updated to reflect a pricing election made in accordance with the terms of a crude oil purchase agreement with Shell Trading (US) Company ("Shell"). This results in a reduction of per barrel transportation costs, resulting in the increased crude oil price realization indicated in the guidance above. 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. However, in the event of an adverse ruling in the litigation, such costs may be required to be paid to by the Company to Shell, which would result in a lower crude oil price realization. Please see Note 11.a. in the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2017 for more information regarding the litigation.

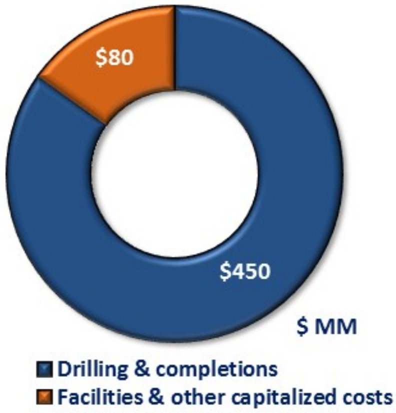
APPENDIX

2017 Capital and Operating Expectations

FY-17E Drilling & Completions
4 Hz rigs
60 - 65 Hz wells drill & complete
~10,000' lateral length average

- **Multi-well package development expected to mitigate parent-child impact**
- **Co-development testing of multiple landing points in UWC/MWC formations to potentially expand high-value inventory**

2017 Capital Budget[1]
$530 MM



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

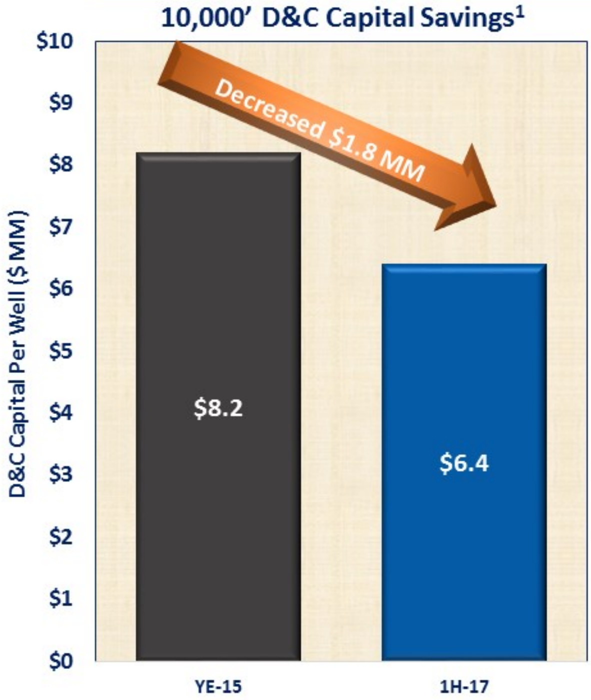
[1] Does not include acquisitions or investments in Medallion-Midland Basin system
Note: Capital budget is unchanged, although upward pressure in service costs, if sustained throughout the remainder of the year, could result in a 5% - 10% increase in the FY-17 capital budget

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%

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

Drilling & Completions Efficiencies Drive Savings



Cost-Efficient Development

Longer laterals

Multi-well packages

Zipper fracing

High-spec rigs

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

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

2016 & 2017 YTD Actuals

		1Q-16	2Q-16	3Q-16	4Q-16	FY-16	1Q-17	2Q-17
Sales Volumes	3-Stream Sales Volumes							
	MBOE	4,204	4,338	4,718	4,889	18,149	4,716	5,336
	BOE/d	46,202	47,667	51,276	53,141	49,586	52,405	58,632
	% oil	48%	46%	46%	46%	47%	45%	47%
Realized Pricing	3-Stream Realized Prices							
	Oil ($/Bbl)	$27.51	$39.37	$39.10	$43.98	$37.73	$46.91	$42.00
	NGL ($/Bbl)	$8.50	$12.24	$11.54	$14.79	$11.91	$16.49	$13.82
	Gas ($/Mcf)	$1.31	$1.31	$2.07	$2.13	$1.73	$2.31	$2.09
	Avg. price ($/BOE)	$17.40	$23.64	$24.34	$27.82	$23.50	$29.42	$26.58
Unit Cost Metrics	3-Stream Unit Cost Metrics ($/BOE)							
	Lease operating expenses	$4.88	$4.43	$3.85	$3.56	$4.15	$3.60	$3.77
	Midstream	$0.14	$0.27	$0.22	$0.26	$0.22	$0.19	$0.17
	Production & ad val taxes	$1.53	$1.84	$1.50	$1.45	$1.58	$1.86	$1.59
	General & administrative[1]							
	Cash	$3.72	$3.33	$3.49	$3.28	$3.45	$3.47	$2.50
	Non-cash stock-based compensation	$0.91	$1.40	$2.05	$1.98	$1.61	$1.96	$1.63
	DD&A	$9.87	$7.88	$7.45	$7.68	$8.17	$7.23	$7.12

[1] Net of amounts capitalized

2015 Actuals

		1Q-15	2Q-15	3Q-15	4Q-15	FY-15
Sales Volumes	**3-Stream Sales Volumes**					
	MBOE	4,274	4,234	4,124	3,714	16,346
	BOE/d	47,487	46,532	44,820	40,368	44,782
	% oil	51%	46%	45%	45%	47%
Realized Pricing	**3-Stream Realized Prices**					
	Oil ($/Bbl)	$41.73	$50.77	$42.88	$36.97	$43.27
	NGL ($/Bbl)	$13.34	$12.85	$10.36	$11.06	$11.86
	Gas ($/Mcf)	$2.14	$1.82	$2.01	$1.76	$1.93
	Avg. price ($/BOE)	$27.64	$29.65	$25.37	$22.47	$26.41
Unit Cost Metrics	**3-Stream Unit Cost Metrics ($/BOE)**					
	Lease operating expenses	$7.58	$6.90	$6.09	$5.83	$6.63
	Midstream	$0.37	$0.38	$0.26	$0.43	$0.36
	Production & ad val taxes	$2.13	$2.24	$1.91	$1.73	$2.01
	General & administrative[1]					
	Cash	$3.99	$4.00	$3.89	$4.27	$4.03
	Non-cash stock-based compensation	$1.12	$1.48	$1.67	$1.77	$1.50
	DD&A	$16.83	$17.03	$16.19	$18.01	$16.99

[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%
Realized 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 val taxes	$5.12	$5.05	$4.14	$3.33	$4.29
	General & administrative[1]					
	Cash	$9.58	$8.88	$6.89	$4.27	$7.07
	Non-cash stock-based compensation	$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 val taxes	$4.28	$4.27	$3.52	$2.85	$3.64
	General & Administrative[1]					
	Cash	$8.01	$7.52	$5.85	$3.66	$6.00
	Non-cash stock-based compensation	$1.49	$2.08	$1.74	$1.44	$1.67
	DD&A	$17.03	$17.23	$17.91	$18.72	$17.83

[1] Net of amounts capitalized

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