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

December 2018
Corporate Presentation

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, midstream and marketing services, 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 (including but not limited to impacts on transportation constraints in the Permian Basin) and the related impact to financial statements as a result of asset impairments and revisions to reserve estimates, availability and cost of equipment and supplies and personnel, availability of sufficient capital to execute the Company’s business plan, impact of compliance with legislation and regulations, including tariffs on steel, 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 those in the Company’s 10-Q for the quarters ended June 30, 2018 and September 30, 2018, 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, 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 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 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, well spacing, drilling and production costs, availability and cost of drilling services and equipment, 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 ultimate recovery from reserves may change significantly as development of the Company’s core assets provides 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. 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.

YTD-18 Highlights & FY-18 Expectations

~17%

Increased FY-18E BOE production growth from initial budget of >10% YoY growth

~71 net wells

Increased FY-18E net Hz completions from initial budget of ~62.5 net wells

~50%

Growth in cash flow from operations YTD-18 vs YTD-17

~1.4x

Net debt to Adjusted EBITDA[1]

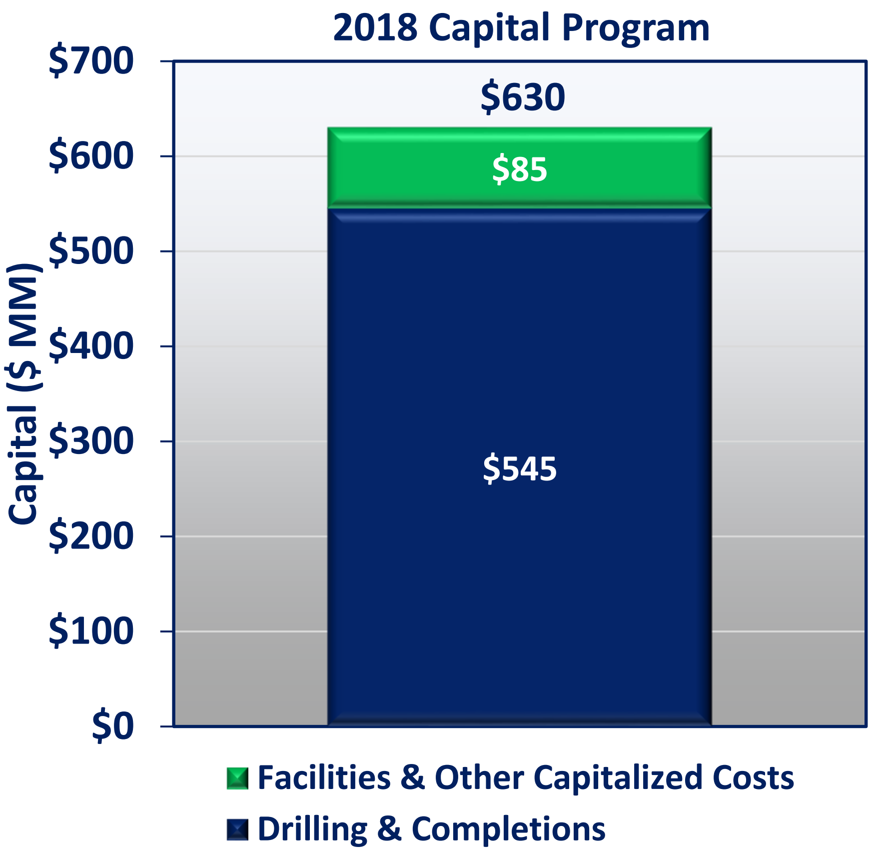
$97.1 million

Utilized, of $200 MM total authorization, to repurchase 11 MM shares through 9/30/18

[1] Net debt to last quarter annualized Adjusted EBITDA is calculated as net debt as of 9/30/18 divided by 3Q-18 Adjusted EBITDA annualized for the year. Net debt as of 9/30/18 is calculated as the face value of long-term debt of $970 MM, reduced by cash on hand of ~$50 MM. See Appendix for a reconciliation of Net Income to Adjusted EBITDA

Note: YTD statistics through 9/30/18

2018 Current Capital Program



- Completing ~71 net wells
- ~10,400' avg. Hz lateral length
- ~96% avg. working interest
- Operational efficiencies enabling a reduction from two completions crews to one in mid-November
- ~$496 MM 9-month cumulative capital expenditures:
  - Drilling & Completions - $443 MM
  - Facilities & Other Capitalized Costs - $53 MM

Expect to spend ~$135 MM of capital in 4Q-18

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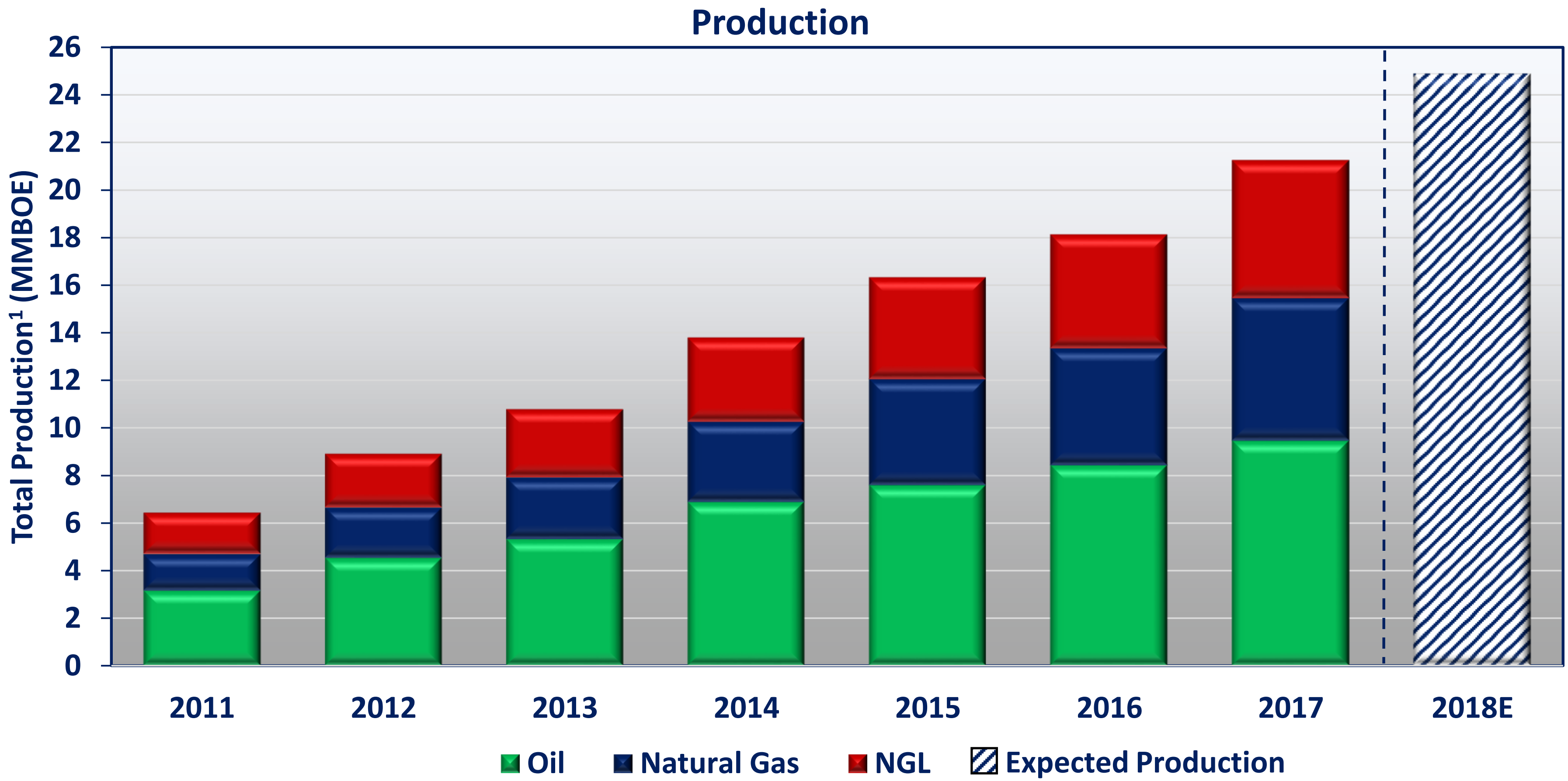
Note: Excludes non-budgeted acquisitions

Consistent Production Growth

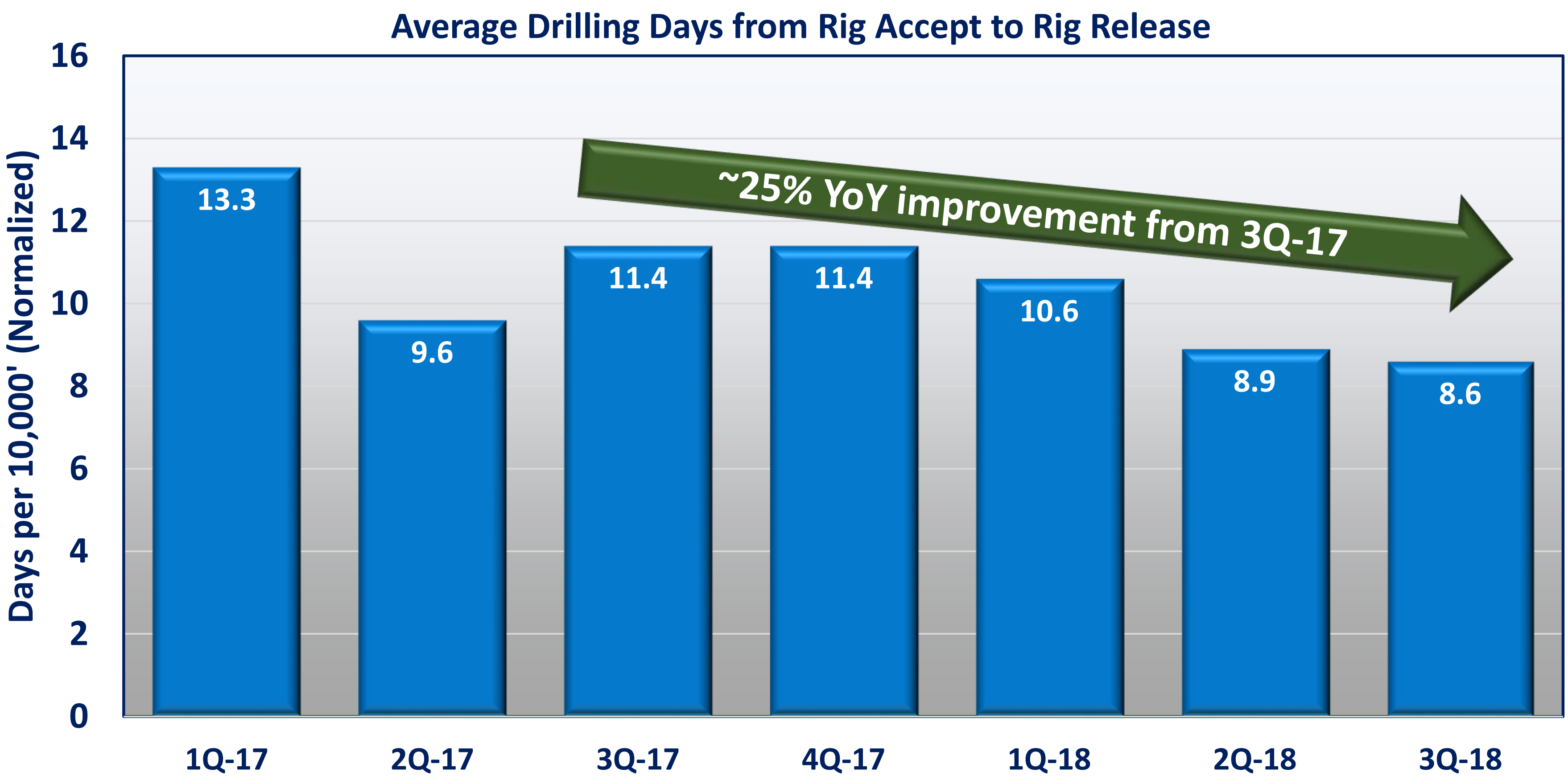


FY-18E YoY BOE production growth ~17%

~7.5% FY-18E YoY oil production growth

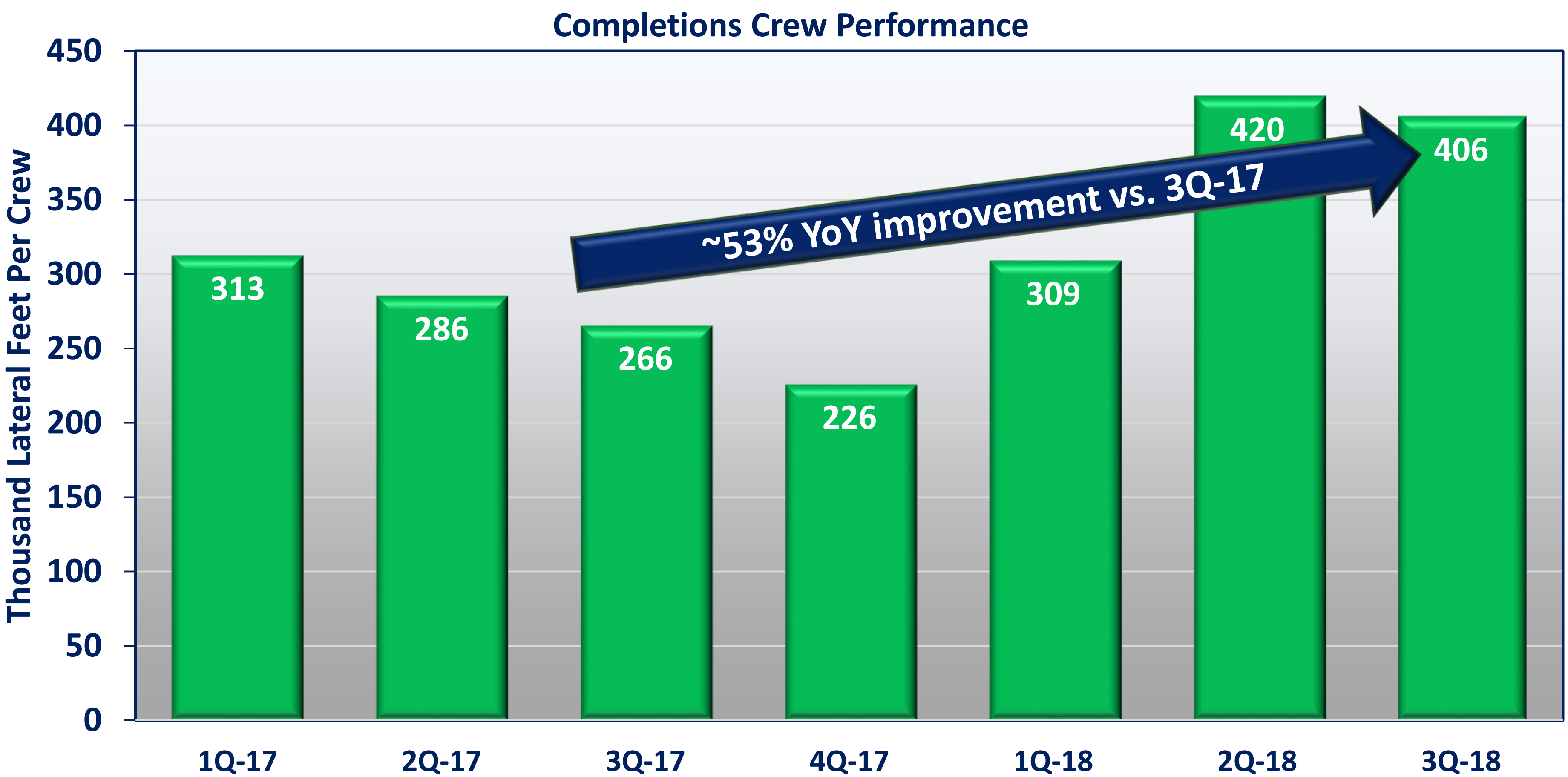
[1] 2011 - 2014 results have been converted to 3-stream using actual gas plant economics. 2011 - 2013 results have been adjusted for Granite Wash divestiture, closed August 1, 2013

Company Record Drilling Efficiencies



Integrated drilling and subsurface modeling is optimizing drilling operations

Improving Cycle Times



High-grading of completions service providers and a focus on best practices is driving efficiency improvements

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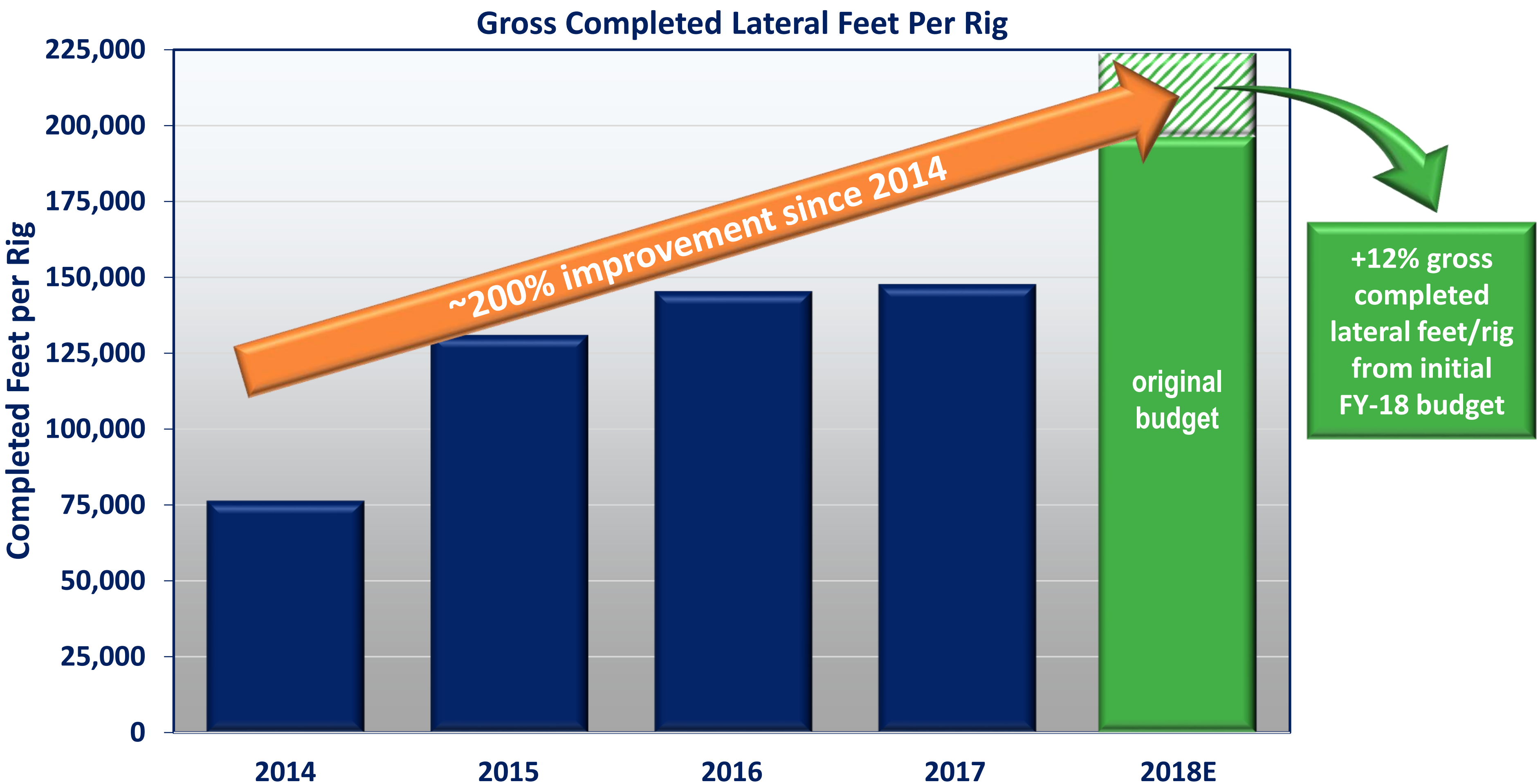
Note: Completions efficiencies data representative of annualized quarterly numbers

Combined Efficiency Improvements



Continuous improvements from drilling & completions efficiencies enable us to do more with less

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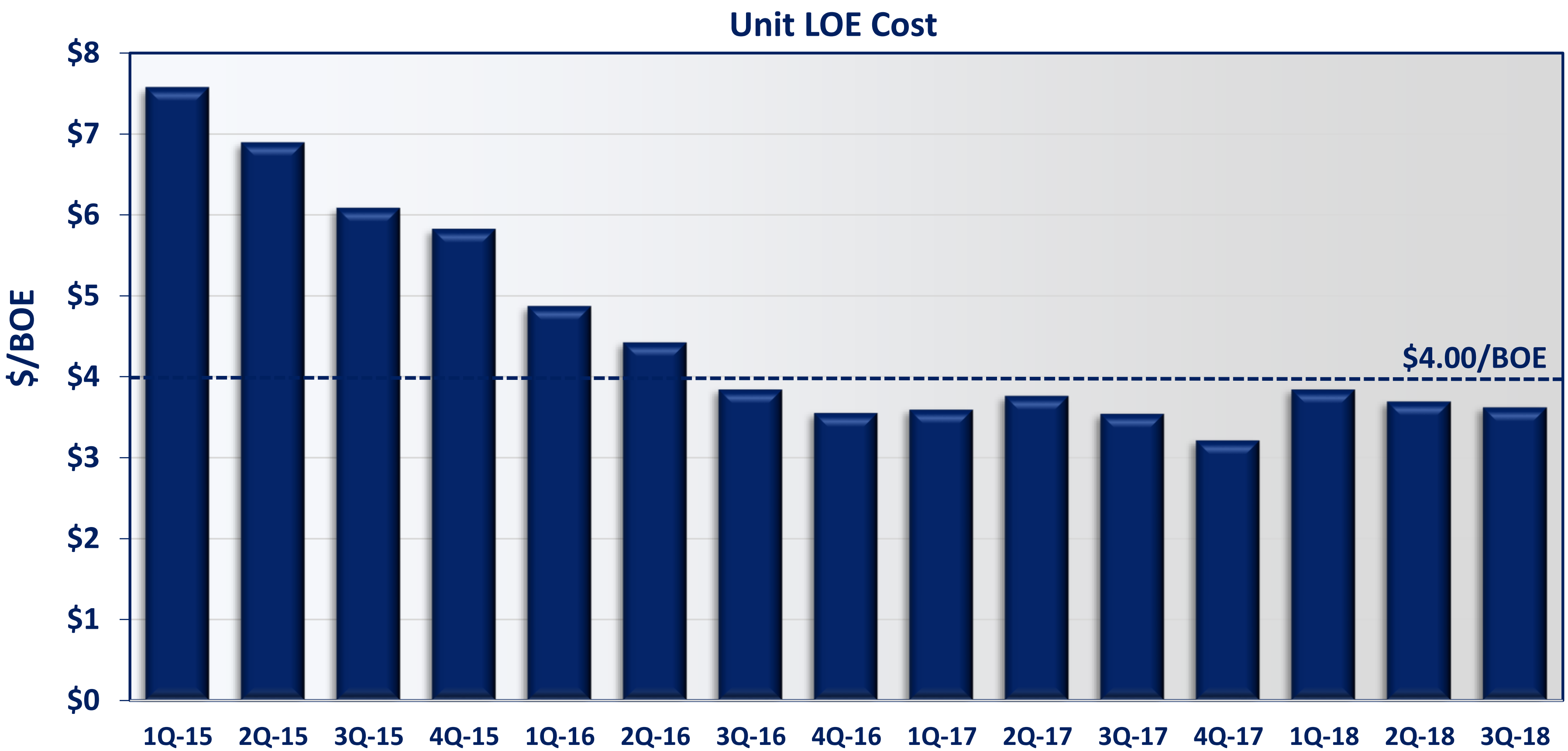
Note: Statistics as of 9/30/2018

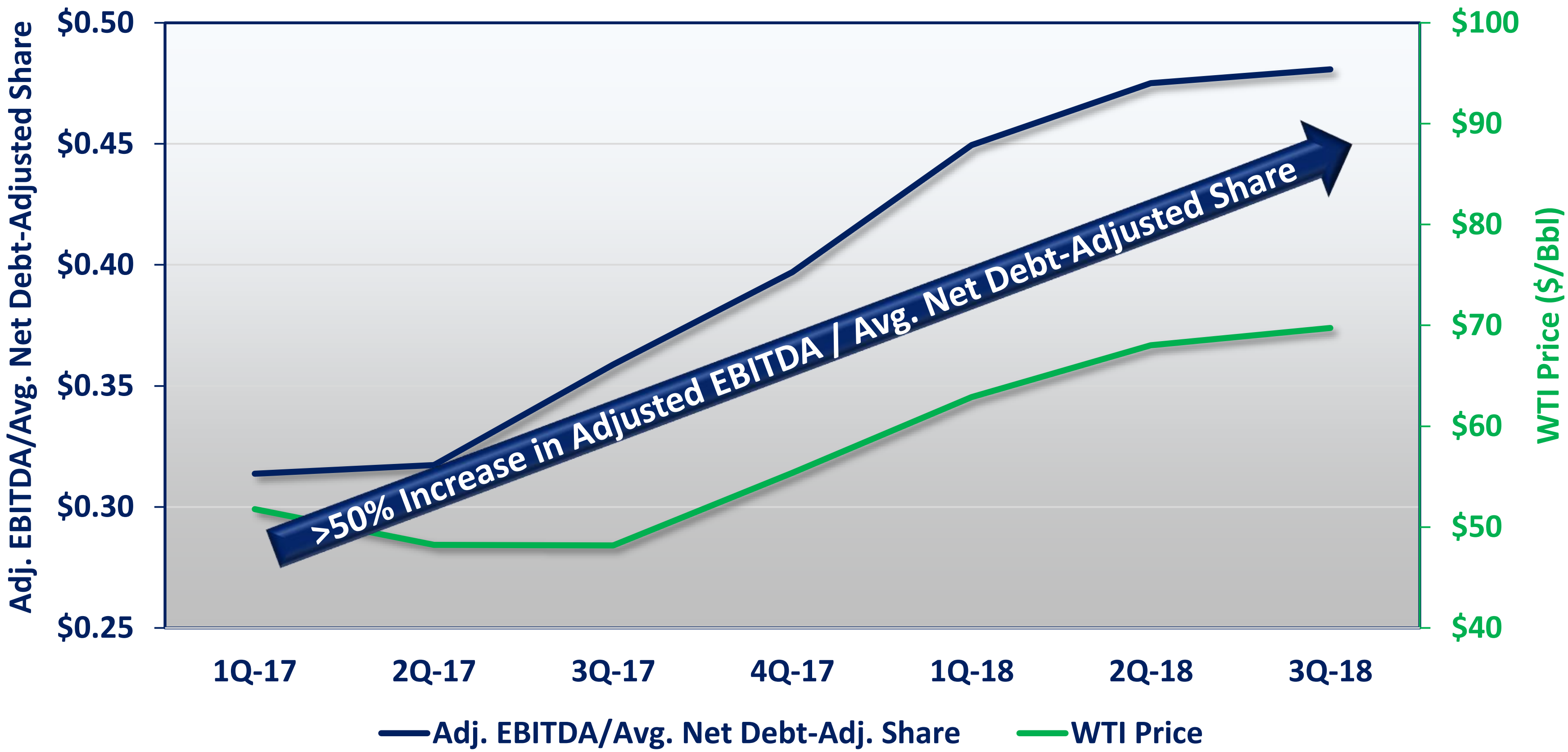
Low Operating Costs



Nine

Quarters below $4.00/BOE

Improving Per Share Value



~1.5x **Grew adjusted EBITDA per average net debt-adjusted share faster than the increase in WTI price since 1Q-17**

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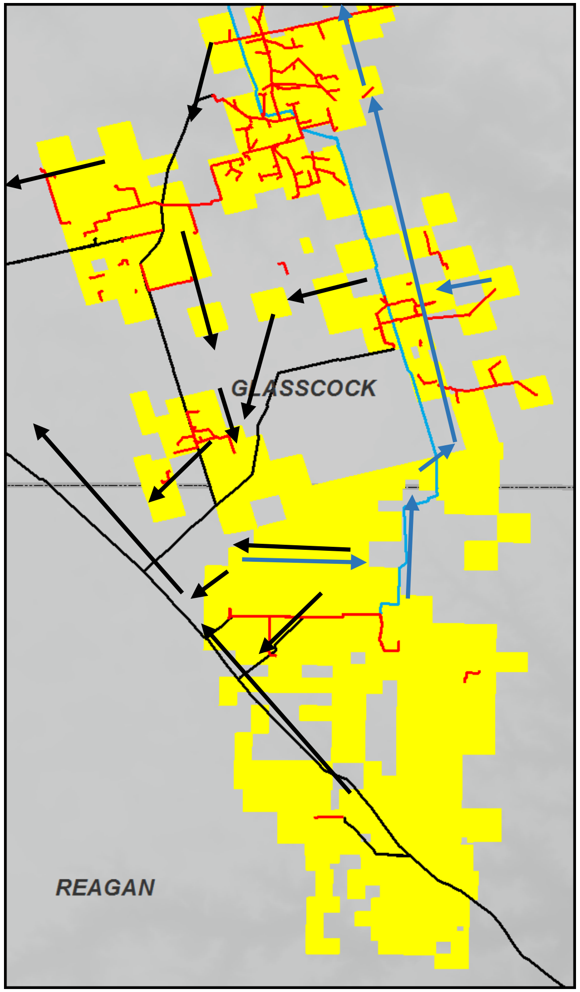
Natural Gas Operational Assurance & Value Protection

- **LMS assets provide field-level optionality to move production to an alternate purchaser when needed**
- **Targa processes >90% of LPI's liquids-rich natural gas volumes**
- **~70% of 4Q-18 natural gas is protected from a widening Waha basis via Waha product hedges & Waha/HH basis hedges[1]**

High confidence in ability to move gas to sales



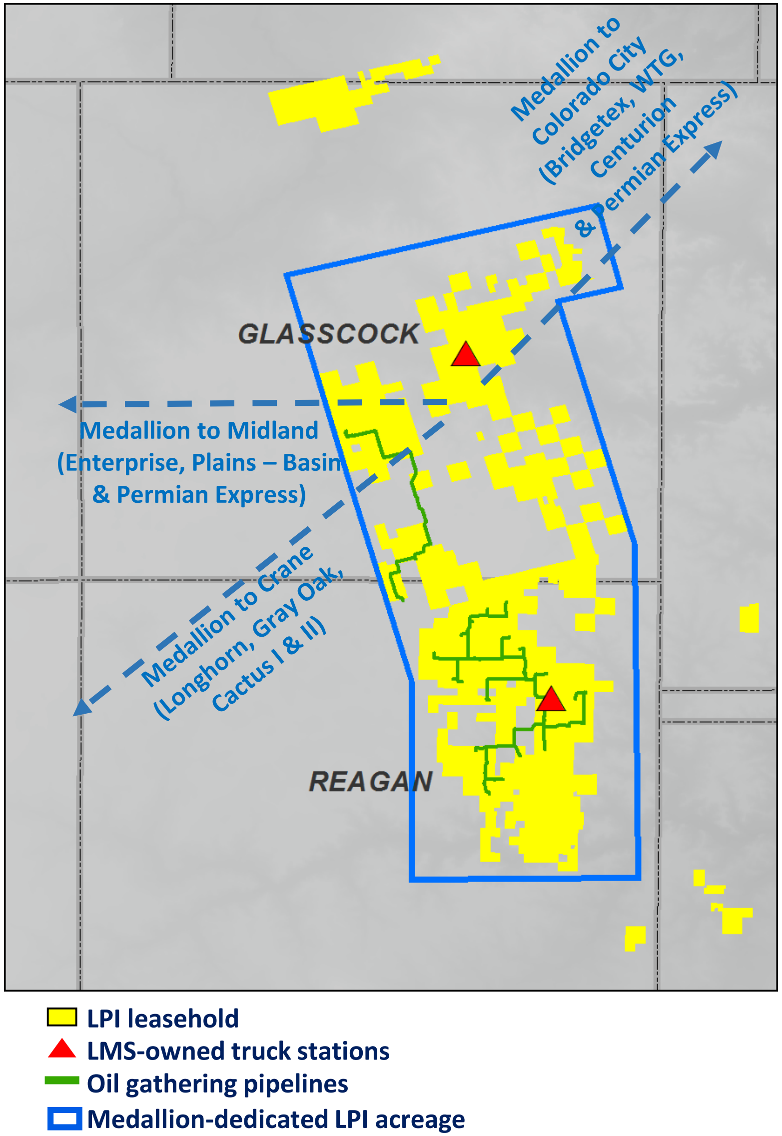
LPI leasehold
LMS natural gas pipelines
Primary 3rd-party takeaway pipelines
Secondary 3rd-party takeaway pipelines

[1]Hedge percentage assumes updated guidance of ~17% YoY total BOE volume growth from FY-17

Crude Flow Assurance Supported By LMS & Medallion Infrastructure

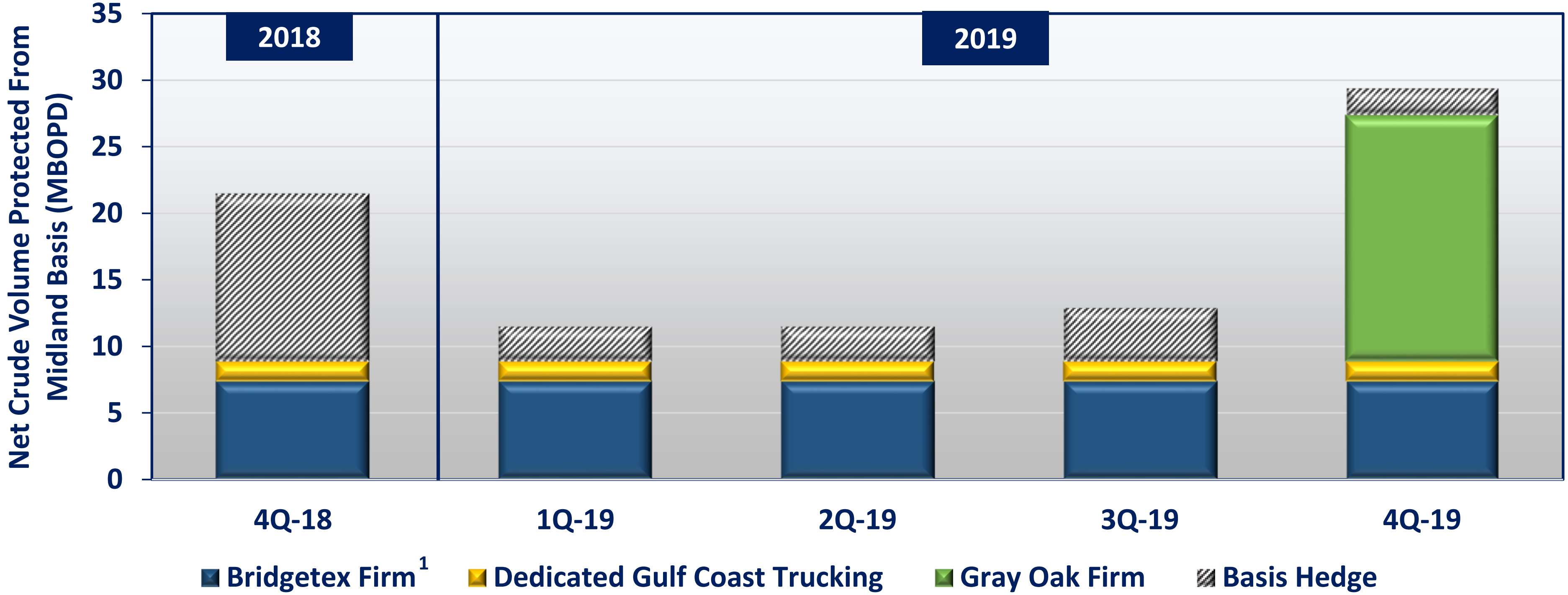
- Medallion firm transportation secured for all dedicated-acreage volumes, including expected future growth
- Long-haul connectivity maximized, as Medallion offers delivery optionality to pipelines that connect to Cushing, Houston, Corpus Christi or Nederland markets
- LMS-owned truck stations shorten hauls to <20 miles, which increases trucking efficiency and reduces costs

~100% **Firm transportation to long-haul pipes exiting the basin**



Note: Medallion connections and long-haul pipes on map are either in service or under construction

Oil Value Protected Via Gulf Coast Access & Financial Contracts



Gross Physical Transportation Contracts:

- 10 MBOPD firm transportation on Bridgetex available through 1Q-26
- 2 MBOPD (Sep-18 thru 2019) dedicated trucking arrangement to Gardendale
- Contracted firm transportation on Gray Oak through 4Q-26E
    - Year 1: 25 MBOPD
    - Years 2 - 7: 35 MBOPD

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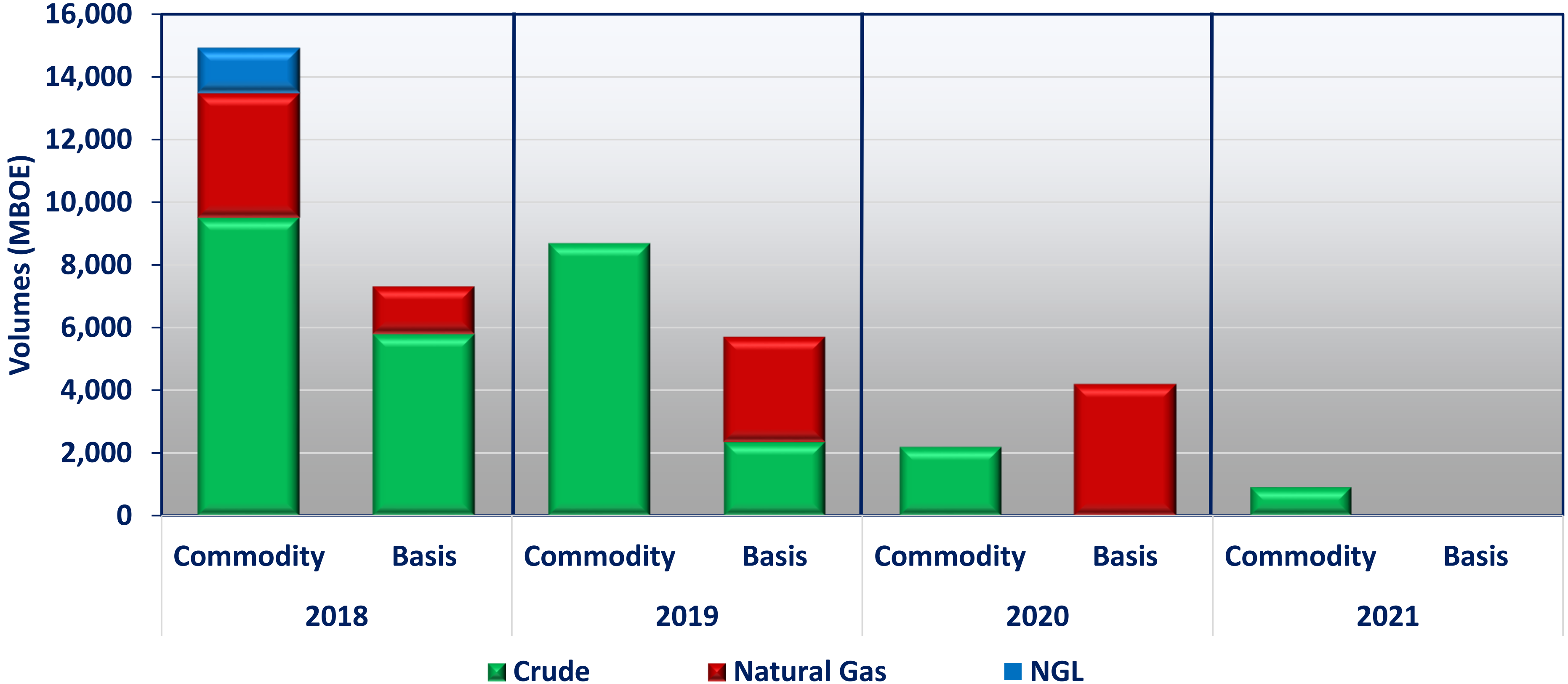
[1] Hou/Mid Jun-18 - Jun-19 basis swaps lock in gain above Bridgetex firm transport during this time period

Consistent Financial Hedging Program



~60% Total production hedged for 4Q-18E

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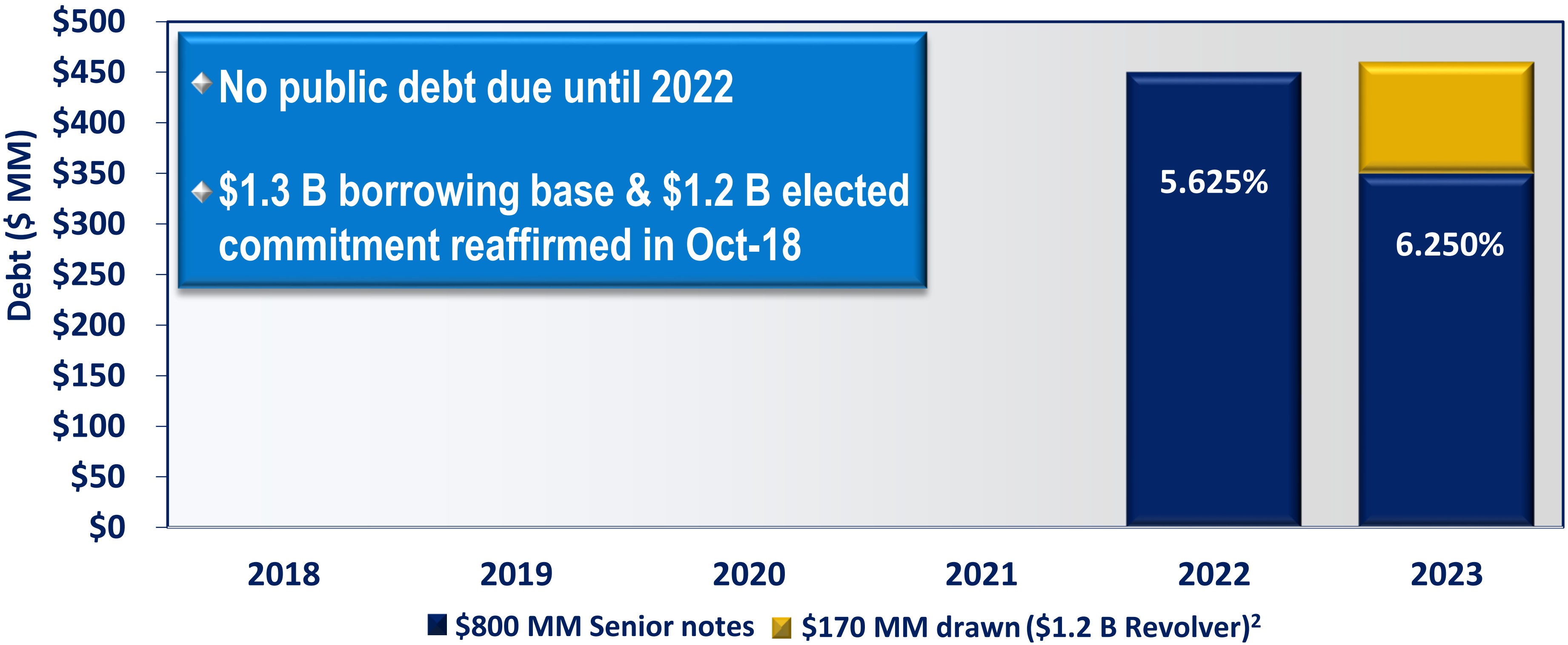
Note: Includes hedges executed through 11/26/18

Maintaining A Strong Balance Sheet

~1.4x net debt to Adjusted EBITDA[1]

Debt Maturity Summary

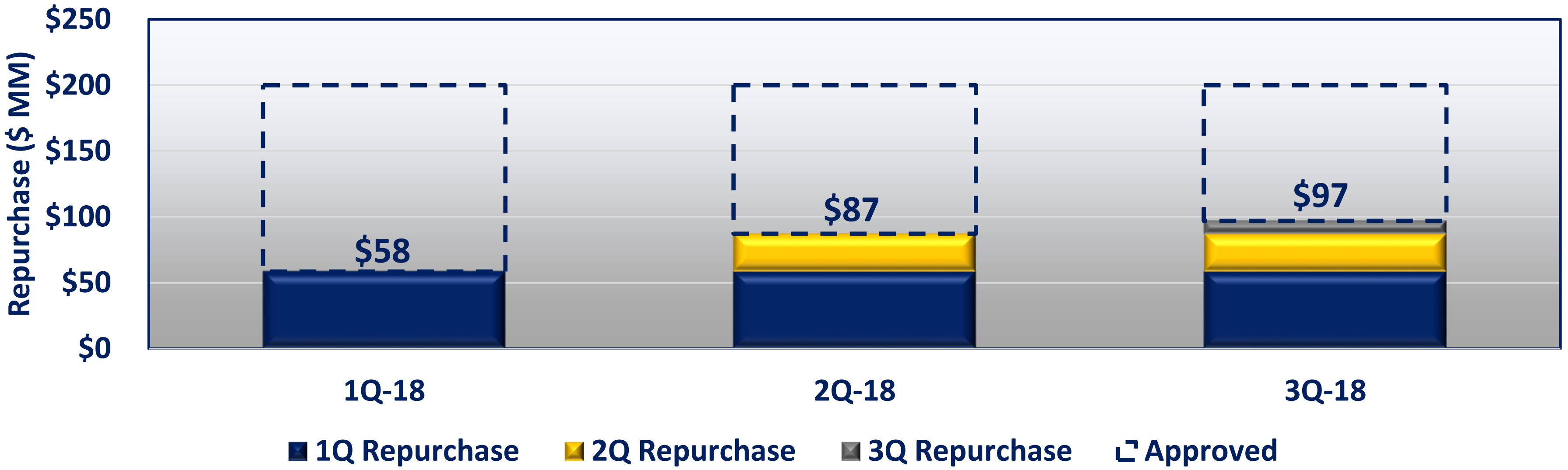


[1] Net debt to last quarter annualized Adjusted EBITDA is calculated as net debt as of 9/30/18 divided by 3Q-18 Adjusted EBITDA annualized for the year. Net debt as of 9/30/18 is calculated as the face value of long-term debt of $970 MM, reduced by cash on hand of ~$50 MM. See Appendix for a reconciliation of Net Income to Adjusted EBITDA

[2]As of 09/30/18, with $1.2 B aggregate elected commitment in place under Fifth Amended and Restated Senior Secured Credit Facility

Stock Repurchase Program

11,048,742 shares of common stock repurchased with a weighted-average share price of $8.78/share



Laredo has successfully executed ~50% of its 24-month Board-approved stock repurchase program

Note: Data through 9/30/2018

Focusing on Improving Capital Efficiency & Returns

Formation	Development Zone	Wells per DSU	
		NAV/ High Density	ROR/ Low Density
UWC	UW-AB UW-CD UWE-MWA	12 - 16 Wells	4 - 8 Wells
MWC	MW-B MW-C MW-D	12 - 16 Wells	4 - 8 Wells
LWC	LW-AB LW-C	6 - 8 Wells	4 Wells
Cline	CLINE-AB CLINE-CD	6 - 8 Wells	4 Wells
Total Well Count per DSU		36 - 48 Wells	16 - 24 Wells

Transitioning to lower-density development in 2019

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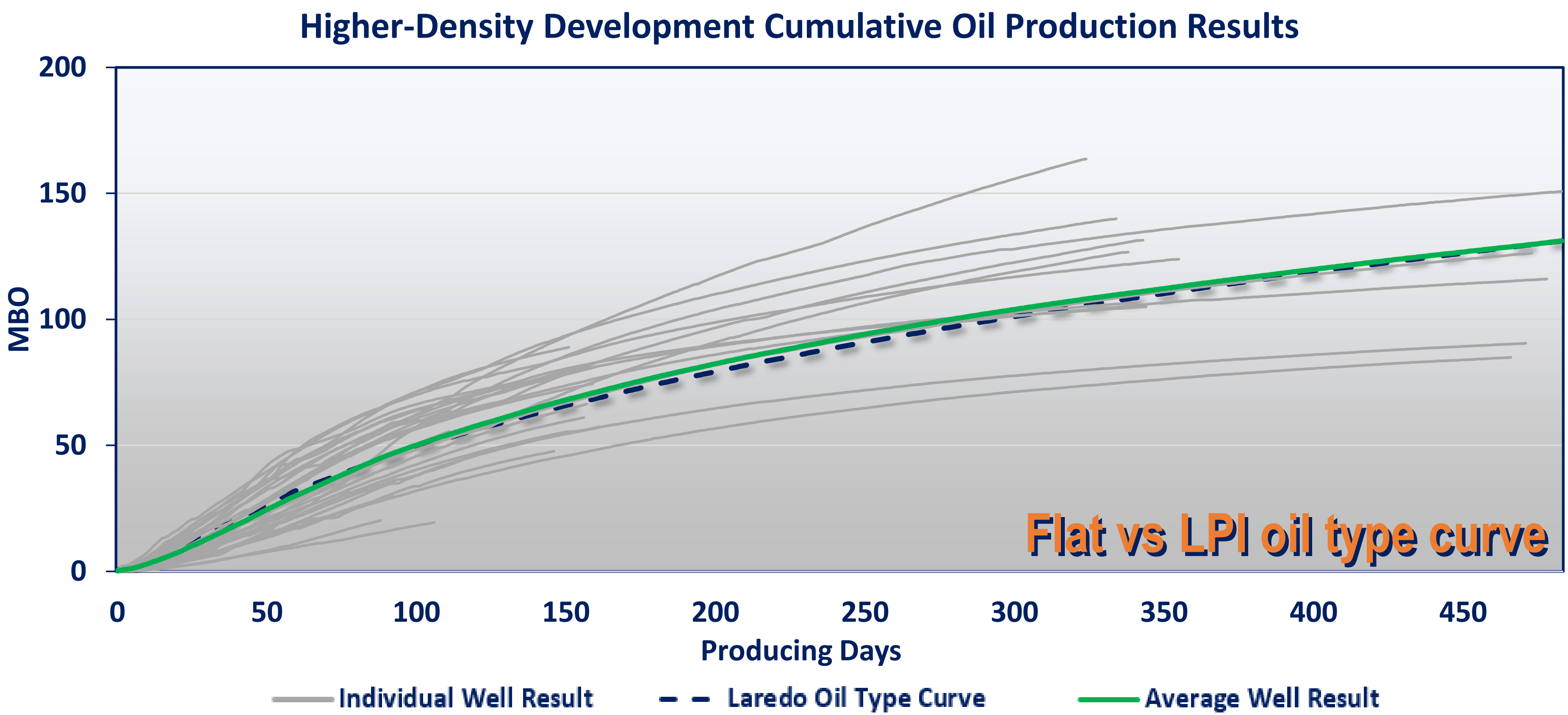
Note: Excludes ABW, Canyon and Spraberry formations
Drilling spacing unit (DSU)

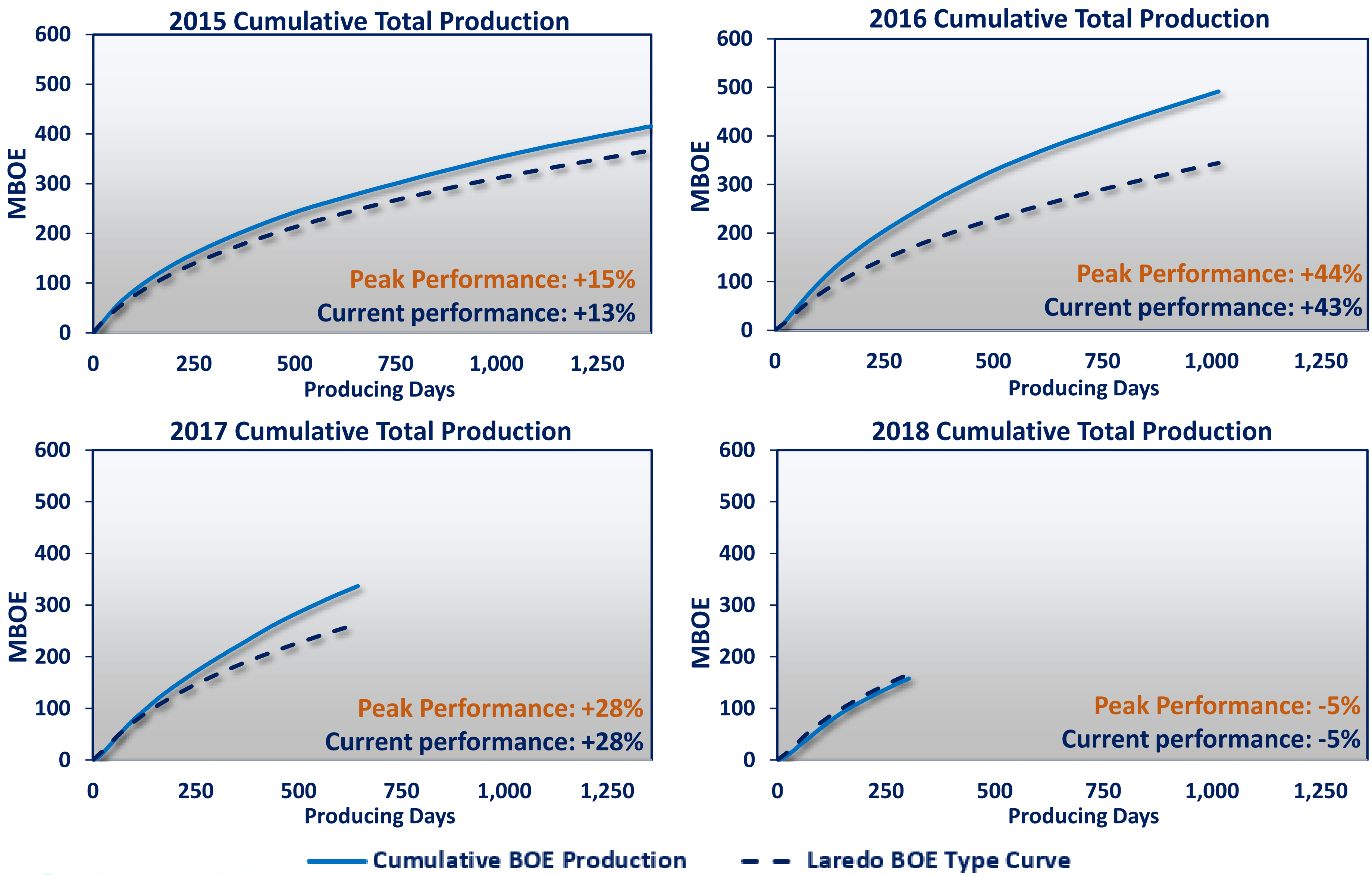
Higher-Density Development Increases Value per DSU



Higher-density packages are experiencing steeper than forecasted oil decline rates

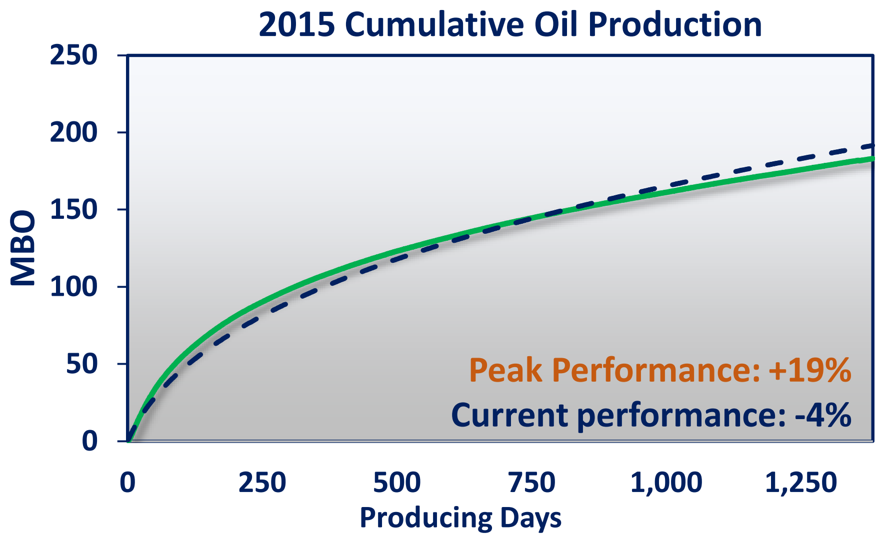
Note: Includes the 29 UWC/MWC wells from the Sugg A 157/158, Lane Trust, Fuchs & Sugg D 104 packages, normalized to 10,000' as of 11/19/18
Type curve representative of Laredo's 1.3 MMBOE UWC/MWC type curve which utilizes a 1.45 b-factor
Drilling spacing unit (DSU)

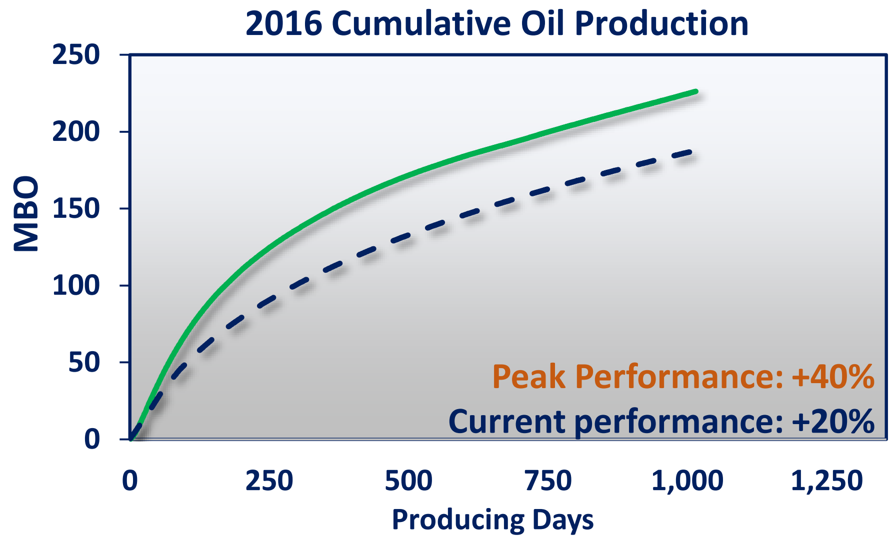
Yearly BOE Completions Performance

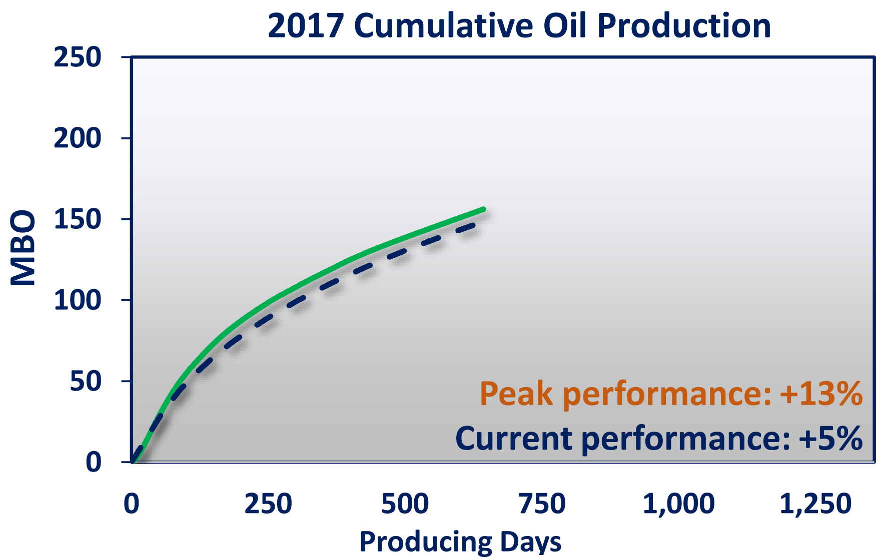


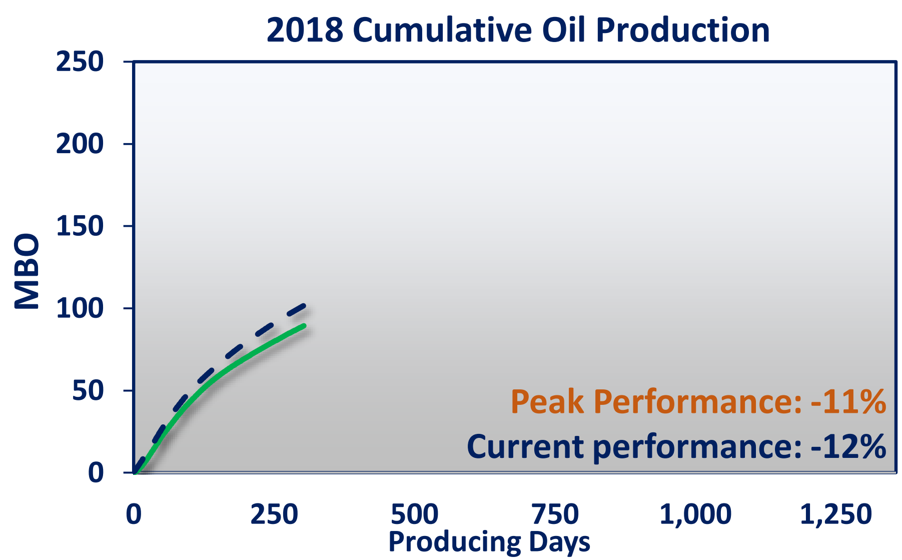
Note: Please see the Appendix slide titled, “Information For Slides 19 & 20” for relevant footnotes

Yearly Oil Completions Performance









Cumulative Oil Production — Laredo Oil Type Curve

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Note: Please see the Appendix slide titled, "Information For Slides 19 & 20" for relevant footnotes

Positioned For The Future

Operational Efficiencies
facilitated by contiguous acreage

Strong Balance Sheet
provides flexibility

Production Corridors
reducing costs & enabling
large well packages

Investment Optionality
enhances shareholder value

APPENDIX

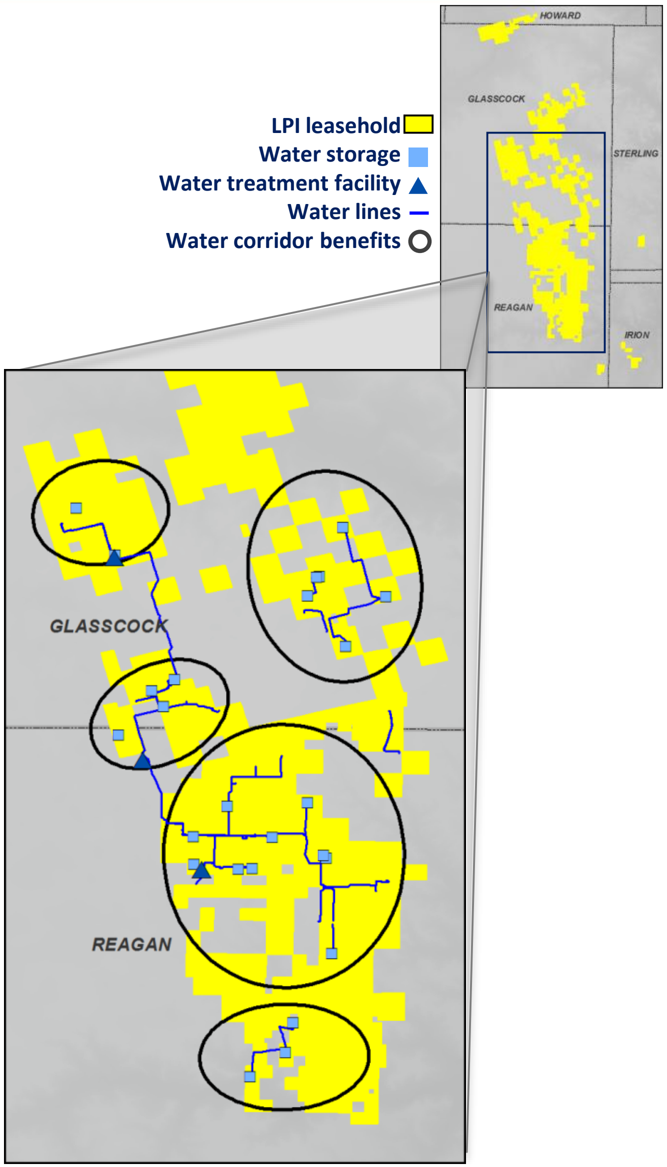
Significant Benefits Through Water Infrastructure Investments

Water Infrastructure

- ~110 miles of water gathering & distribution pipelines
- ~75% of produced water gathered by pipe and ~33% of produced water recycled in FY-18E
- 54 MBWPD recycling processing capacity
- 22.5 MMBW owned or contracted storage capacity

>$19 MM

FY-18E net savings generated by LMS water infrastructure investments[1]



[1]Calculated utilizing a 95% WI & 74% NRI

Note: Statistics, estimates and maps as of 9/30/18

Oil, Natural Gas & Natural Gas Liquids Hedges

Hedge Product Summary	4Q-18	FY-19	FY-20	FY-21
Oil total floor volume (Bbl)	2,398,175	8,687,000	2,196,000	912,500
Oil wtd-avg floor price ($/Bbl)	$47.42	$47.91	$47.27	$45.00
Nat gas total floor volume (MMBtu)	5,983,400			
Nat gas wtd-avg floor price ($/MMBtu)	$2.50			
NGL total floor volume (Bbl)	395,600			

Oil	4Q-18	FY-19	FY-20	FY-21
Puts				
Hedged volume (Bbl)	1,367,775	8,030,000	366,000	
Wtd-avg floor price ($/Bbl)	$51.93	$47.45	$45.00	
Swaps				
Hedged volume (Bbl)		657,000	695,400	
Wtd-avg price ($/Bbl)		$53.45	$52.18	
Collars				
Hedged volume (Bbl)	1,030,400		1,134,600	912,500
Wtd-avg floor price ($/Bbl)	$41.43		$45.00	$45.00
Wtd-avg ceiling price ($/Bbl)	$60.00		$76.13	$71.00

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	4Q-18	FY-19	FY-20	FY-21
Swaps - Ethane				
Hedged volume (Bbl)	156,400			
Wtd-avg price ($/Bbl)	$11.66			
Swaps - Propane				
Hedged volume (Bbl)	128,800			
Wtd-avg price ($/Bbl)	$33.92			
Swaps – Normal Butane				
Hedged volume (Bbl)	46,000			
Wtd-avg price ($/Bbl)	$38.22			
Swaps - Isobutane				
Hedged volume (Bbl)	18,400			
Wtd-avg price ($/Bbl)	$38.33			
Swaps - Natural Gasoline				
Hedged volume (Bbl)	46,000			
Wtd-avg price ($/Bbl)	$57.02			

Note: Natural gas liquids derivatives 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

Natural Gas - WAHA	4Q-18	FY-19	FY-20	FY-21
Puts				
Hedged volume (MMBtu)	2,055,000			
Wtd-avg floor price ($/MMBtu)	$2.50			
Collars				
Hedged volume (MMBtu)	3,928,400			
Wtd-avg floor price ($/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

Basis Swaps	4Q-18	FY-19	FY-20	FY-21
Mid/Cush				
Hedged volume (Bbl)	920,000	552.000		
Wtd-avg price ($/Bbl)	-$0.56	-$4.37		
Hou/Mid				
Hedged volume (Bbl)	920,000	1,810,000		
Wtd-avg price ($/Bbl)	$7.30	$7.30		
Waha/HH				
Hedged volume (MMBtu)	2,300,000	20,075,000	25,254,000	
Wtd-avg price ($/MMBtu)	-$0.62	-$1.05	-$0.76	

Note: Other than the oil basis swaps, the Company's oil derivatives are settled based on the month's average daily NYMEX index price for the first nearby month of the West Texas Intermediate Light Sweet Crude Oil Futures Contract. The oil basis swaps are settled based on either (i) the differential between the Argus Americas Crude West Texas Intermediate ("WTI") index prices for WTI Midland-weighted average for the trade month and WTI Cushing-WTI formula basis for the trade month as compared to the basis swaps' fixed differential price or (ii) the differential between the Argus Americas Crude WTI Houston-weighted average price for the trade month and the WTI Midland-weighted average price for the trade month as compared to the basis swaps' fixed differential price. The Company's NGL derivatives are settled based on the month's average daily OPIS index price for Mont Belvieu Purity Ethane, TET and Non-TET Propane, Non-TET Butane, Non-TET Isobutane and Non-TET Natural Gasoline. Other than the natural gas basis swaps, the Company's natural gas derivatives are settled based on the Inside FERC index price for West Texas WAHA for the calculation period. The natural gas basis swaps are settled based on the differential between the Inside FERC index price for West Texas WAHA for the calculation period and the NYMEX Henry Hub index price for the calculation period as compared to the basis swaps' fixed differential price

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Note: Open positions as of 9/30/2018, hedges executed through 11/26/18

4Q-18 Guidance

	4Q-18E
Production (MBOE/d)……	70.5
Crude oil production (MBbl/d)……	28.2
Price Realizations (pre-hedge):	
Crude oil (% of WTI)……	90%
Natural gas liquids (% of WTI)……	33%
Natural gas (% of Henry Hub)……	40%
Operating Costs & Expenses:	
Lease operating expenses ($/BOE)……	$3.65
Midstream service expenses ($/BOE)……	$0.15
Transportation and marketing expenses ($/BOE)……	$0.80
Production and ad valorem taxes (% of oil, NGL and natural gas revenue)……	6.25%
General and administrative expenses:	
Cash ($/BOE)……	$2.50
Non-cash stock-based compensation ($/BOE)……	$1.40
Depletion, depreciation and amortization ($/BOE)……	$9.00

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Information for Slides 19 & 20

Horizontal drilling in unconventional wells using enhanced completions techniques, including but not limited to hydraulic fracturing, is a relatively new process and, as such, forecasting the long-term production of such wells is inherently uncertain and subject to varying interpretations. As we receive and process geological and production data from these wells over time, we analyze such data to confirm whether previous assumptions regarding original forecasted production and reserves continue to appear accurate, or require modification. While all production forecasts have elements of uncertainty over the life of the related wells, we are seeing indications that the oil portion of such reserves may be less than originally anticipated.

Initial production results, production decline rates, well density, completion design and operating method are examples of the numerous uncertainties and variables inherent in the estimation of proved reserves in future periods. The quantity of proved reserves is one of the many variables inherent in the calculation of depletion. Negative revisions in the estimated quantities of proved reserves have the effect of increasing the rates of depletion on the affected properties, which decreases earnings and increases losses through higher depletion expense. We have experienced increased depletion per BOE sold for each of the last three quarters of 2018.

The table below presents our depletion per BOE sold for the periods presented:

	1Q-18	2Q-18	3Q-18
Depletion per BOE sold..	$ 7.34	$ 7.68	$ 7.94

2018 cumulative production charts include:

- All 66 wells targeting the Company's primary development formations with first oil production starting in 2018
  - Well count: 59 UWC/MWC normalized to 10,000' as of 11/19/18
- Type curve representative of Laredo's 1.3 MMBOE UWC/MWC

2017 cumulative production charts include:

- All 63 wells targeting the Company's primary development formations with first oil production starting in 2017
  - Well count: 52 UWC/MWC, 3 LWC & 8 Cline, normalized to 10,000' as of 11/19/18
- Type curve representative of a weighted average of Laredo's 1.3 MMBOE UWC/MWC, 0.9 MMBOE LWC & 1.0 MMBOE Cline type curves

2016 cumulative production charts include:

- All 45 wells targeting the Company's primary development formations with first oil production starting in 2016
  - Well count: 43 UWC/MWC & 2 Cline, normalized to 10,000' as of 11/19/18
- Type curve representative of a weighted average of Laredo's 1.3 MMBOE UWC/MWC & 1.0 MMBOE Cline type curves

2015 cumulative production charts include:

- All 56 wells targeting the Company's primary development formations with first oil production starting in 2015
  - Well count: 32 UWC, 9 MWC, 9 LWC & 6 Cline, normalized to 10,000' as of 11/19/18
- Type curve representative of a weighted average of Laredo's 1.1 MMBOE UWC, 1.0 MMBOE MWC, 0.9 MMBOE LWC & 1.0 MMBOE Cline type curves

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 depletion, depreciation and amortization, non-cash stock-based compensation, net, accretion expense, mark-to-market on derivatives, premiums paid for derivatives, interest expense, gains or losses on disposal of assets and other non-recurring income and expenses. Adjusted EBITDA provides no information regarding a company's capital structure, borrowings, interest costs, capital expenditures, working capital movement or tax position. Adjusted EBITDA does not represent funds available for discretionary use because those funds are required for debt service, capital expenditures, 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, the 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.

**** On October 30, 2017, LMS, together with Medallion Midstream Holdings, LLC, 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 Gathering & Processing, LLC ("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 were $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.**

Supplemental Non-GAAP Financial Measure Reconciliation-Continued

(in thousands)	1Q-17	2Q-17	3Q-17	4Q-17	1Q-18	2Q-18	3Q-18
Net income	$ 68,276	$ 61,110	$ 11,027	$ 408,561	$ 86,520	$ 33,452	$ 55,050
Plus:							
Income tax expense	-	-	-	1,800	-	-	1,387
Depletion, depreciation and amortization	34,112	38,003	41,212	45,062	45,553	50,762	55,963
Non-cash stock-based compensation, net	9,224	8,687	8,966	8,857	9,339	10,676	8,733
Accretion expense	928	943	951	969	1,106	1,121	1,114
Mark-to-market on derivatives:							
(Gain) loss on derivatives, net	(36,671)	(28,897)	27,441	37,777	(9,010)	45,976	32,245
Settlements (paid) received for matured derivatives, net	7,451	13,705	13,635	2,792	(2,236)	181	(3,888)
Cash settlements received for early terminations of derivatives, net	-	4,234	-	-	-	-	-
Cash premiums paid for derivatives	(2,107)	(9,987)	(1,448)	(12,311)	(4,024)	(5,451)	(5,455)
Interest expense	22,720	23,173	23,697	19,787	13,518	14,424	14,845
Gain on sale of investment in equity method investee**	-	-	-	(405,906)	-	-	-
(Gain) loss on disposal of assets, net	214	(805)	991	906	2,617	1,358	616
Loss on early redemption of debt	-	-	-	23,761	-	-	-
Income from equity method investee	(3,068)	(2,471)	(2,371)	(575)	-	-	-
Proportionate Adjusted EBITDA of equity method investee[1]	6,365	6,601	6,789	2,326	-	-	-
Adjusted EBITDA	$ 107,444	$ 114,296	$ 130,890	$ 133,806	$ 143,383	$ 152,499	$ 160,610

[1] Proportionate Adjusted EBITDA of Medallion, our equity method investee until its sale on October 30, 2017, is calculated as follows:

(in thousands)	1Q-17	2Q-17	3Q-17	4Q-17	1Q-18	2Q-18	3Q-18
Income from equity method investee	$ 3,068	$ 2,471	$ 2,371	$ 575	$ -	$ -	$ -
Adjusted for proportionate share of depreciation & amortization	3,297	4,130	4,418	1,751	-	-	-
Proportionate Adjusted EBITDA of equity method investee	$ 6,365	$ 6,601	$ 6,789	$ 2,326	$ -	$ -	$ -

LAREDO PETROLEUM