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

# Corporate Presentation
# June 2019

LAREDO PETROLEUM

# Forward-Looking / Cautionary Statements

This presentation, including any oral statements made regarding the contents of this presentation, contains forward-looking statements as defined under Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, that address activities that Laredo Petroleum, Inc. (together with its subsidiaries, the "Company", "Laredo" or "LPI") assumes, plans, expects, believes, intends, projects, estimates or anticipates (and other similar expressions) will, should or may occur in the future, including, but not limited to, the share repurchase program, which may be suspended or discontinued by the Company at any time, are forward-looking statements. The forward-looking statements are based on management's current belief, based on currently available information, as to the outcome and timing of future events.

General risks relating to Laredo include, but are not limited to, the decline in prices of oil, natural gas liquids and natural gas and the related impact to financial statements as a result of asset impairments and revisions to reserve estimates, the increase in service costs, hedging activities, possible impacts of pending or potential litigation and other factors, including those and other risks described in its Annual Report on Form 10-K for the year ended December 31, 2018, and those set forth from time to time in other filings with the Securities Exchange Commission ("SEC"). These documents are available through Laredo's website at www.laredopetro.com under the tab "Investor Relations" or through the SEC's Electronic Data Gathering and Analysis Retrieval System at www.sec.gov. Any of these factors could cause Laredo's actual results and plans to differ materially from those in the forward-looking statements. Therefore, Laredo can give no assurance that its future results will be as estimated. Laredo does not intend to, and disclaims any obligation to, update or revise any forward-looking statement.

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 "resource potential," "estimated ultimate recovery" ("EURs") or "type curve," each of which the SEC guidelines restrict from being included in filings with the SEC without strict compliance with SEC definitions. These terms refer to the Company's internal estimates of unbooked hydrocarbon quantities that may be potentially 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. "Estimated ultimate recovery," or "EURs," are based on the Company's previous operating experience in a given area and publicly available information relating o the operations of producers who are conducting operations in these areas. Unbooked resource potential or EURs do not constitute reserves within the meaning of the Society of Petroleum Engineer's Petroleum Resource Management System or SEC rules and do not include any proved reserves. Actual quantities of reserves that may be ultimately recovered from the Company's interests may differ substantially from those presented herein. Factors affecting ultimate recovery include the scope of the Company's ongoing drilling program, which will be directly affected by the availability of capital, decreases in oil, natural gas liquids and natural gas prices, well spacing, drilling costs and production costs, availability and costs of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory approvals, negative revisions to reserve estimates and other factors as well as actual drilling results, including geological and mechanical factors affecting recovery rates. Estimates of EURs may change significantly as development of the Company's core assets provides additional data. In addition, our production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases. "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.

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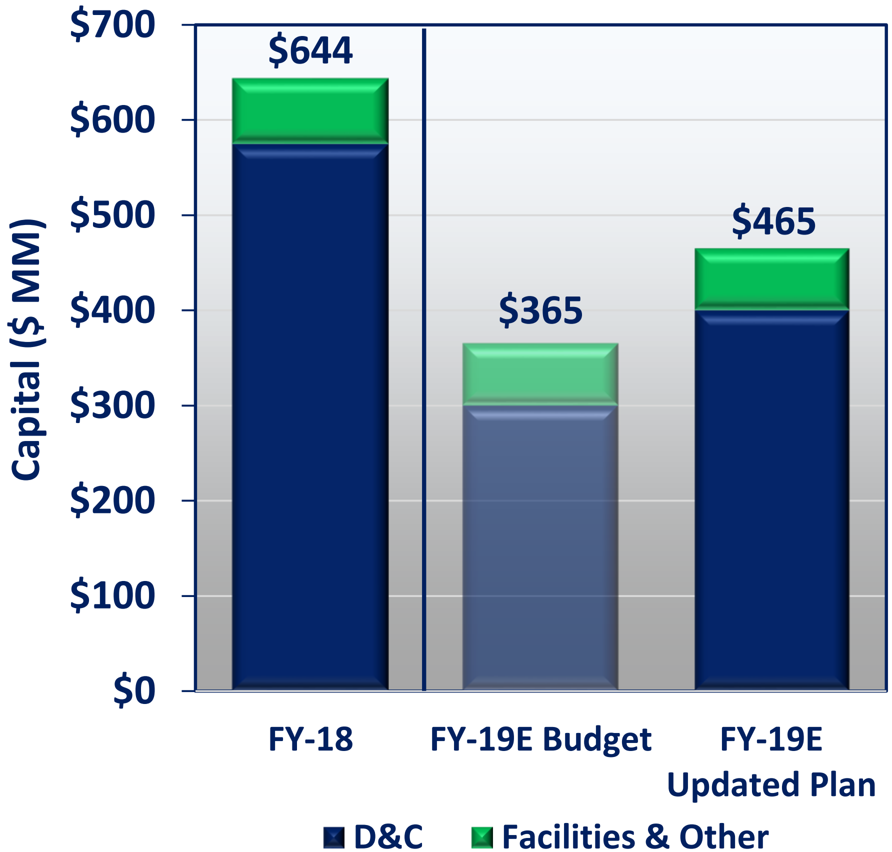
# 2019: A Transitional Year

| | |
|---|---|
| **Operating within Cash Flow** | ▪ Tailoring operational cadence & corporate cost structure to balance capital expenditures and cash flow from operations<br>▪ Protected cash flow by restructuring Bal-19 and FY-20 hedges, increasing the wtd.-avg. WTI floors to $60.42/BO & $58.79/BO for Bal-19 & FY-20, respectively |
| **Optimized Operations** | ▪ ~$700,000 of negotiated Bal-19 per-well savings, reducing YE-18 well costs by ~9% and bolstering per-well returns by ~5%<br>▪ Widening of spacing is anticipated to improve well results, rates of return and capital efficiency versus FY-18 |
| **Reconstructed Management Team** | ▪ Named new President and announced CEO succession plan<br>▪ Promoted new COO, CFO & General Counsel, and reduced officer-level positions by ~40% |
| **Right-Sized Employee Base** | ▪ ~20% reduction in employee base<br>▪ ~$20 MM of YoY FY-19E cash & non-cash G&A expense & capitalized savings<br>▪ ~$10 MM of additional annual cash & non-cash G&A expense & capitalized savings expected beyond FY-19 |

***Strategy evolution is expected to drive long-term capital efficiency improvements and higher returns versus 2018***

# 2019 Capital Program Demonstrates Flexibility & Discipline




| | FY-19E Budget | FY-19E Updated Plan |
|---|---|---|
| Average FY Rig Count | 1.8 | 2.3 |
| Average FY Completions Crew Count | 0.9 | 1.3 |
| Completions Activity | Thru July | FY-19 |
| # Gross Completions | ~36 | ~52 |
| YoY Production Growth - BOE | +9% | +11% |
| YoY Production Growth - BO | -5% | -2% |

***Higher FY-19 operational cadence underpinned by hedge restructure while maintaining focus on cash flow neutrality***

Note: Excludes non-budgeted acquisitions & includes cash & non-cash capital
FY-19E budget capital plan based on $54/BO WTI & $2.90/MMBtu HH
FY-19E updated capital plan based on $58/BO WTI & $2.90/MMBtu HH

# Restructured Hedges Underpin Updated Plan

## Original Budget – Bal-19

| | |
|---|---|
| $54.00 Per BO | $47.91 Per BO |
| Internal Price Deck | Weighted-Avg. Floor |
| ~90% | -5% |
| Hedged Production | YoY Oil Growth |

## Original Budget – FY-20

| | |
|---|---|
| $54.15 Per BO | $47.27 Per BO |
| Internal Price Deck | Weighted-Avg. Floor |
| ~20% | -13% |
| Hedged Production | YoY Oil Growth |

## Updated Plan – Bal-19

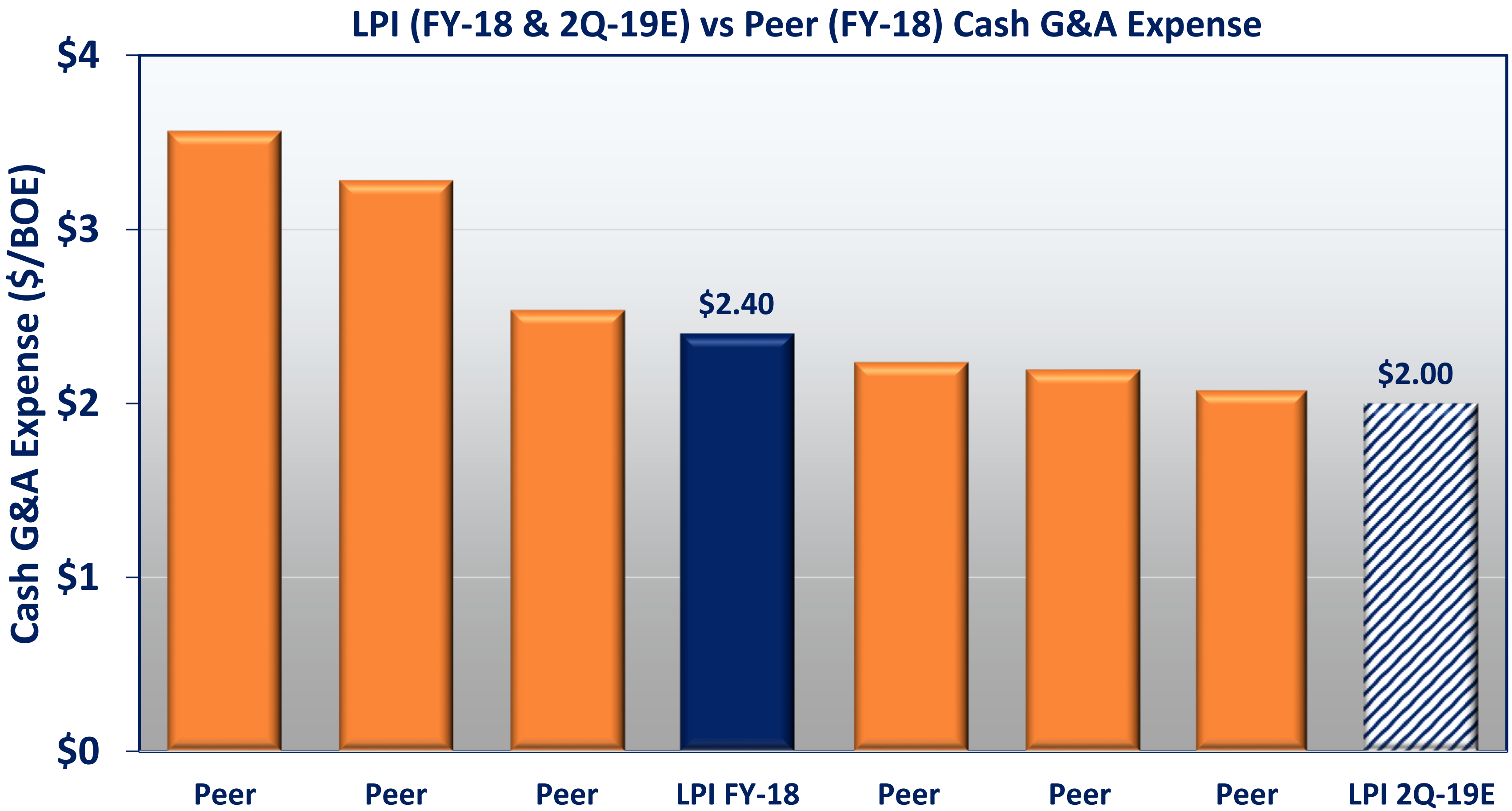
| | |
|---|---|
| $59.25 Per BO | $60.42 Per BO |
| Internal Price Deck | Weighted-Avg. Floor |
| ~90% | -2% |
| Hedged Production | YoY Oil Growth |

## Updated Plan – FY-20

| | |
|---|---|
| $58.00 Per BO | $58.79 Per BO |
| Internal Price Deck | Weighted-Avg. Floor |
| ~75% | ~flat |
| Hedged Production | YoY Oil Growth |

***Updated plan improves expected YoY oil production within protected cash flow by 3% and 19% in FY-19 & FY-20, respectively***

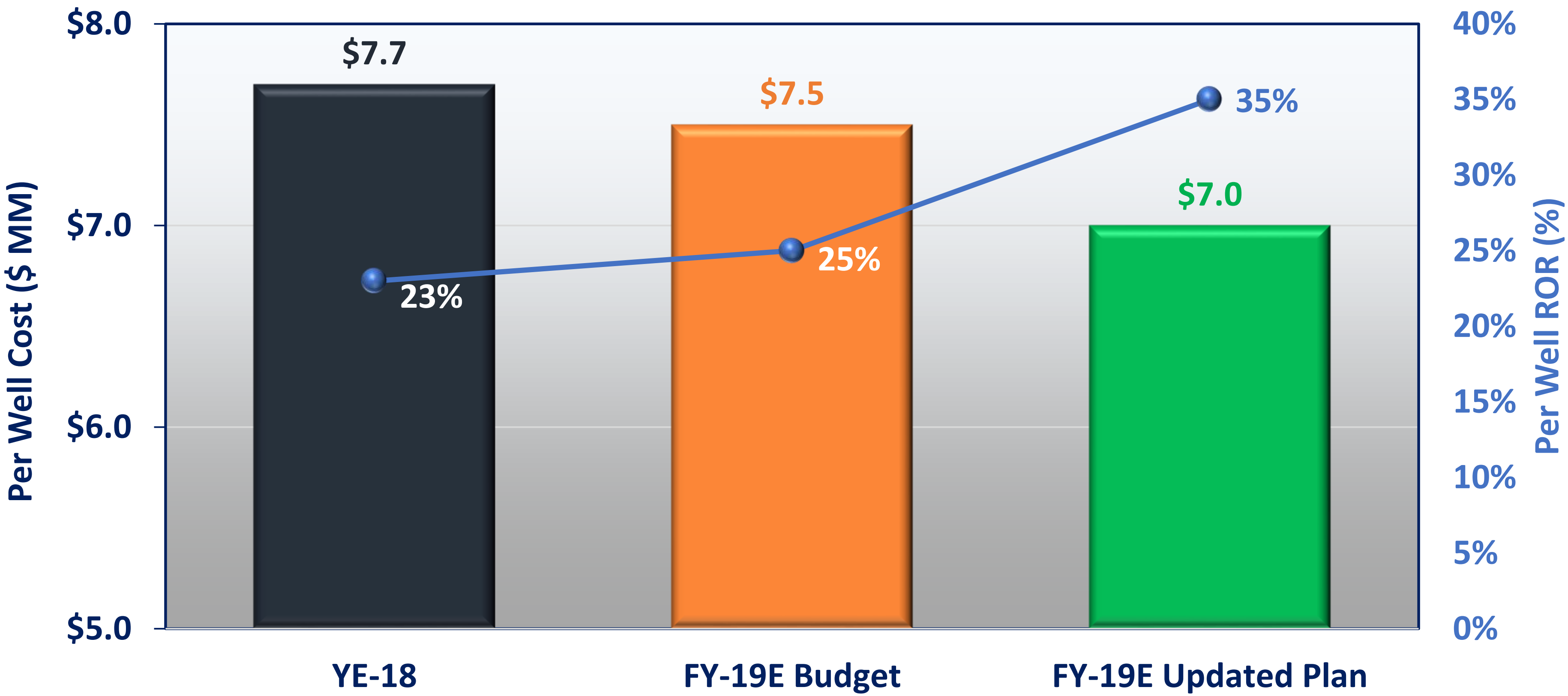
# Right Sized Our Cost Structure As Promised




**~$30 MM** YoY annualized cash & non-cash G&A expense & capitalized savings expected

Note: Peers include: CPE, CXO, PE, PXD, QEP, SM

# Improving Well Costs & Higher Pricing Bolster Well Returns




**~$700,000 Per well savings captured since YE-18**

**Higher pricing & well cost savings are improving per well returns by ~12%**

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Note: Well costs indicative of a 10,000' UWC/MWC utilizing a 2-well pad
YE-18 and FY-19E budget returns are based on pricing of $54/BO WTI & $2.90/MMBtu HH
FY-19E updated plan returns are based on pricing of $58/BO WTI & $2.90/MMBtu HH

# Delivering on Wider Spacing Earlier than Promised

| Formation | Target Landing Zone | ROR/Wide Spacing | | |
|---|---|---|---|---|
| | | Wells per DSU | Drill Pattern | Inventory |
| UWC | UW-AB<br>UW-CD<br>UWE-MWA | 4 – 8 | | 200 - 400 |
| MWC | MW-B<br>MW-C<br>MW-D | 4 – 8 | | 200 - 400 |
| LWC | LW-AB<br>LW-C | 4 | | 400 |
| Cline | CLINE-AB<br>CLINE-CD | 4 | | 400 |
| Total Well Count | | 16 - 24 | | 1,200 – 1,600 |

● 1,320’ single zone development ● 1,320’ co-development

***All second quarter completions will be developed in the UWC/MWC at 4 - 8 wells per DSU***

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

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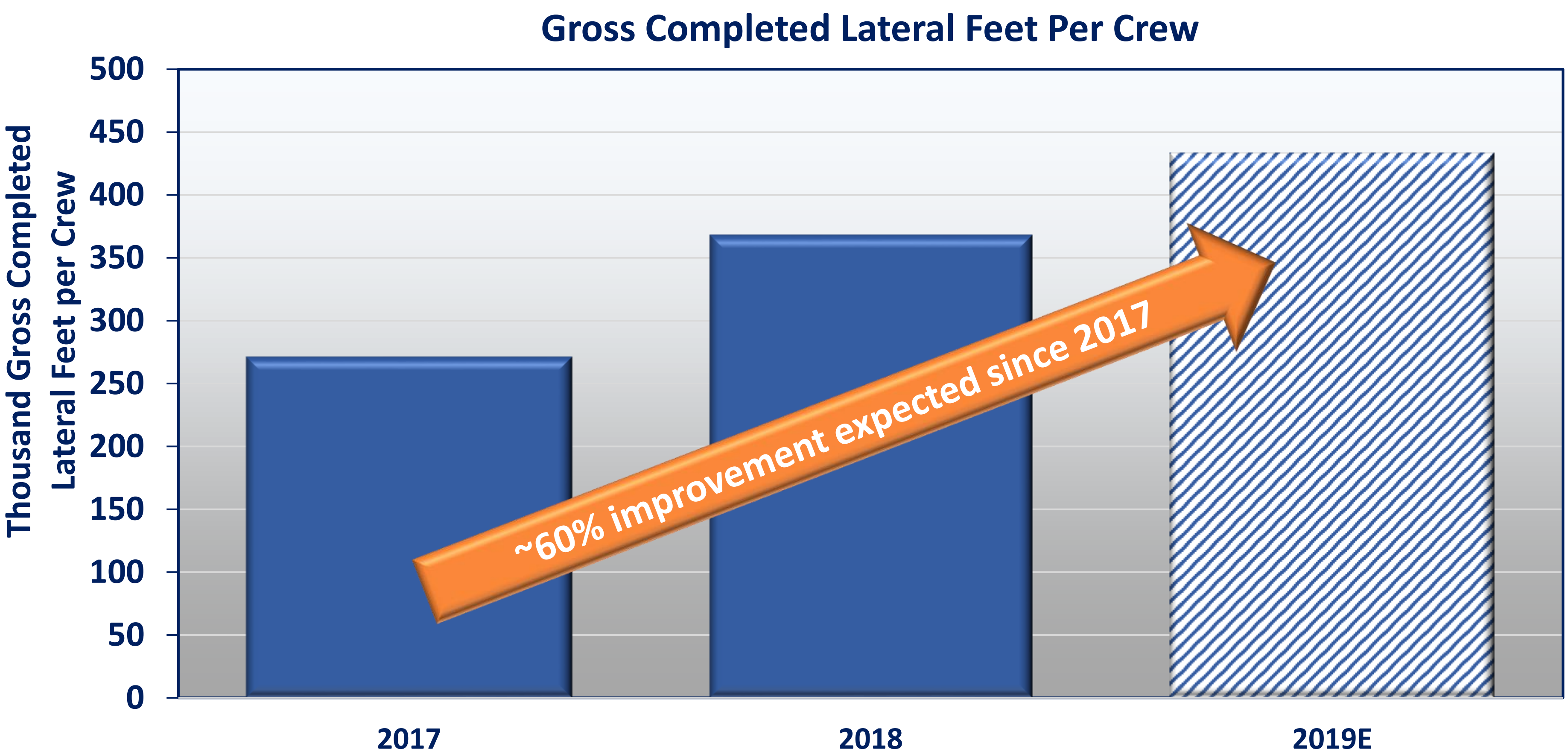
# History of Improving Efficiencies Expected to Continue




***Completions efficiencies accelerate cash flow and improve well costs***

# Contiguous Acreage & Robust Infrastructure Are Strategic Cornerstones

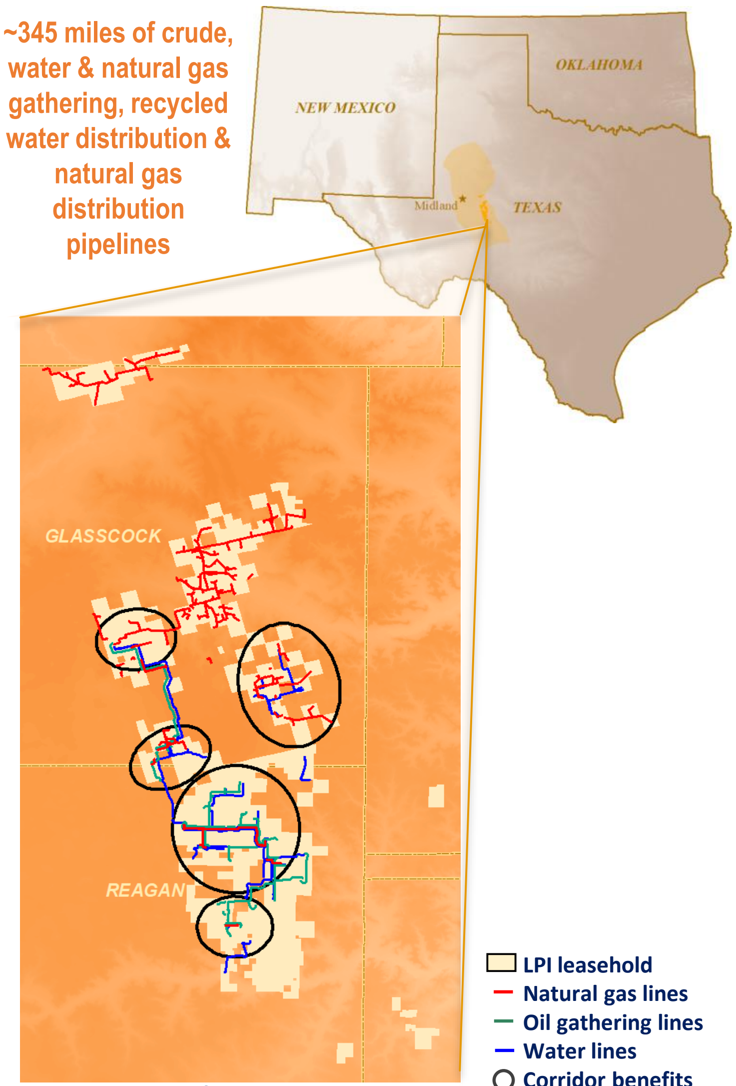
## 1Q-19 Infrastructure Impact

- ~$11 MM of net benefits from capital & LOE savings, price uplift and LMS net operating income
- $0.58/BOE reduction in unit LOE, helping to reduce operating costs
- ~130,000 truckloads eliminated from the field, yielding safer roads and a cleaner environment

**~87%**

**HBP acreage, enabling a concentrated development plan along production corridors**

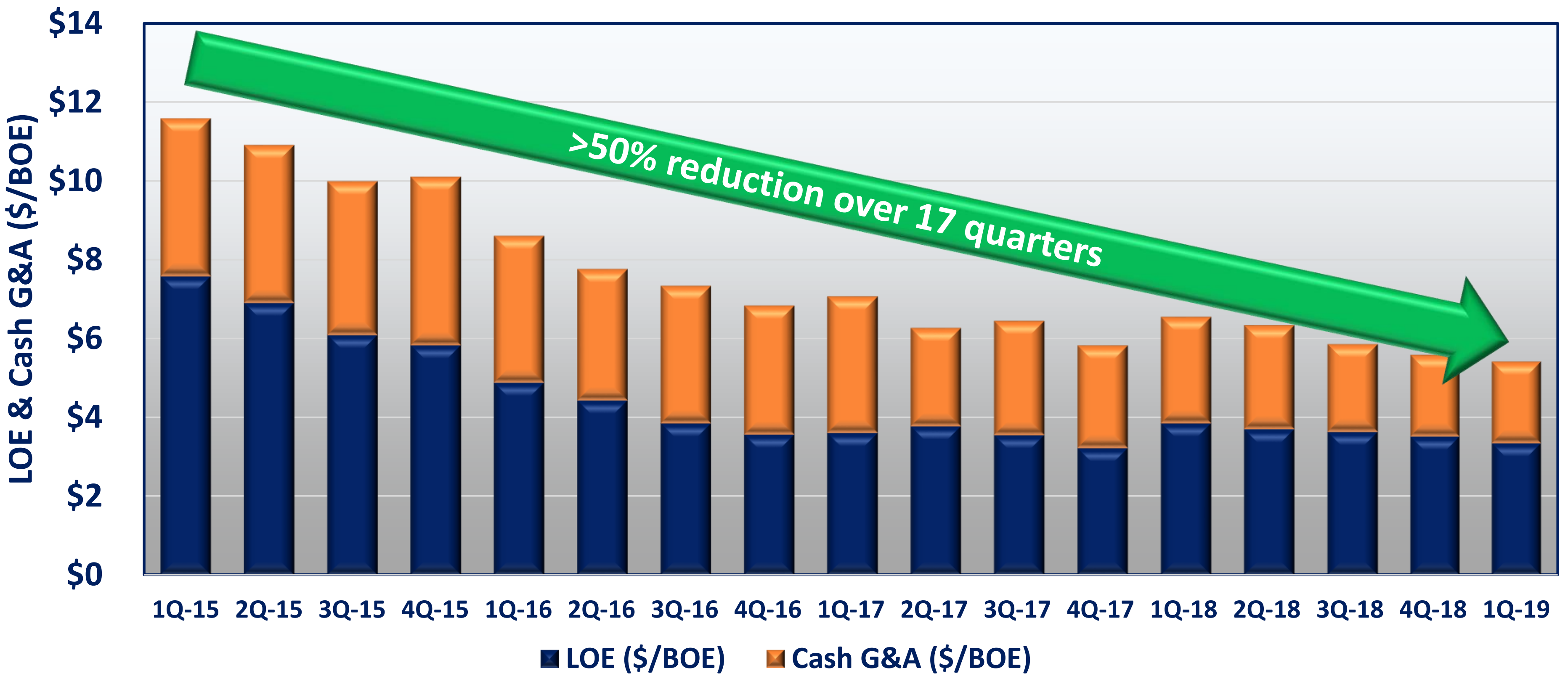
~345 miles of crude, water & natural gas gathering, recycled water distribution & natural gas distribution pipelines




137,512 gross/ 122,461 net acres

Note: Map, acreage count and statistics as of 3/31/19

# Substantial Reduction in Controllable Cash Costs




***Expect to continue trending down in 2019 as the previously-executed reduction in force decreases unit G&A and field infrastructure continues to drive unit LOE costs among the lowest in the Midland Basin***

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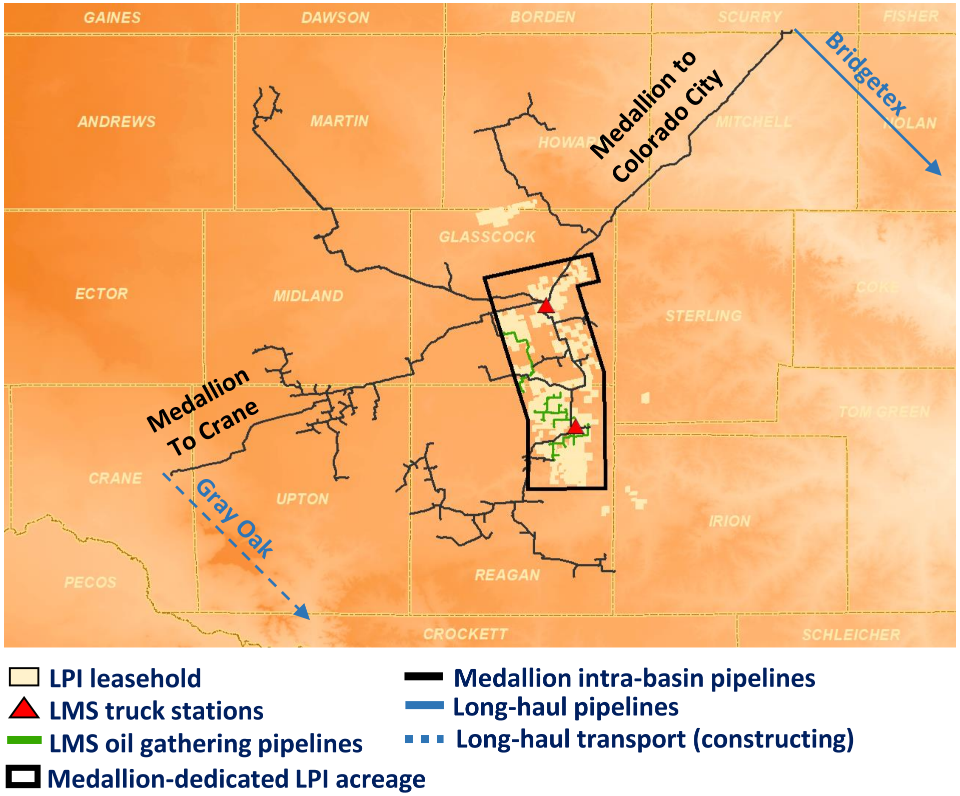
# Oil Value Enhanced Via Gulf Coast Access

**Long-Haul Connectivity Via Medallion:**

- Medallion firm transportation secured for all crude oil produced within dedication area
- Long-haul connectivity maximized, as Medallion offers delivery optionality to pipelines that connect to Cushing, Houston, Corpus Christi and Nederland markets

**Gross Physical Transportation Contracts:**

- 10 MBOPD firm transportation on Bridgetex through 1Q-22, with option to extend through 1Q-26 (USGC pricing)
- Firm transportation on Gray Oak through 4Q-26E (Brent-related pricing):
  - Year 1: 25 MBOPD
  - Years 2 - 7: 35 MBOPD
- In the event that Laredo's long-haul transportation capacity exceeds production, contracts will be fulfilled by the purchase of crude oil at Colorado City or Crane for shipment to and sale at Gulf Coast pricing



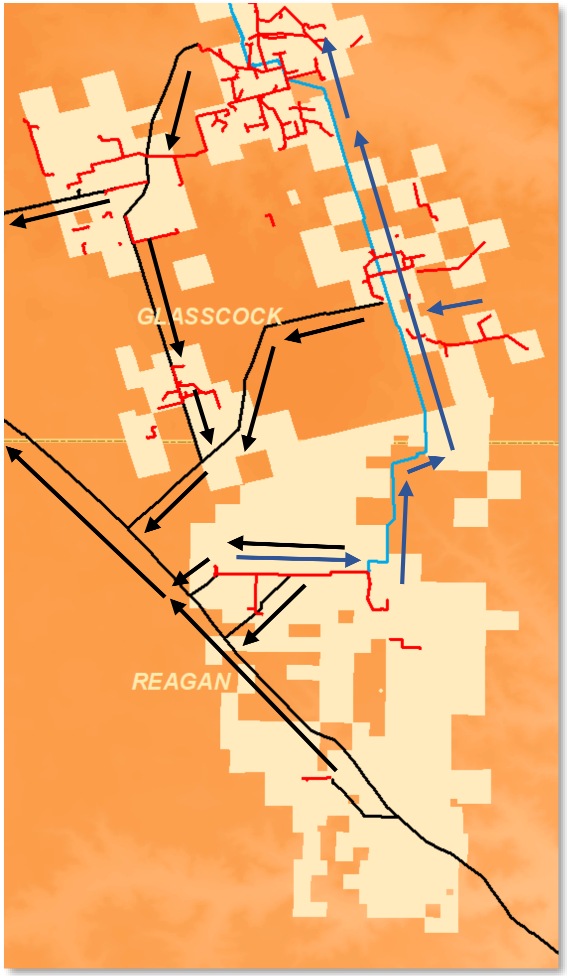

Note: Map as of 3/31/19

# Natural Gas Operational Assurance & Value Protection

- LMS assets provide field-level optionality to move production to an alternate purchaser when needed
- Targa processes ~95% of LPI's liquids-rich natural gas volumes
- ~70% of bal-19E natural gas is hedged via HH swaps & Waha/HH basis swaps

| Bal-19E ($/MMBtu) | Benchmark as of 4/18/19 | Hedged Wtd.-Avg. Floor Price[1] |
|---|---|---|
| HH | $2.64 | $3.09 |
| Waha Basis | -$1.65 | -$1.51 |
| Waha | $0.99 | $1.58 |

60% Expected improvement in natural gas prices due to HH and Waha basis hedges




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

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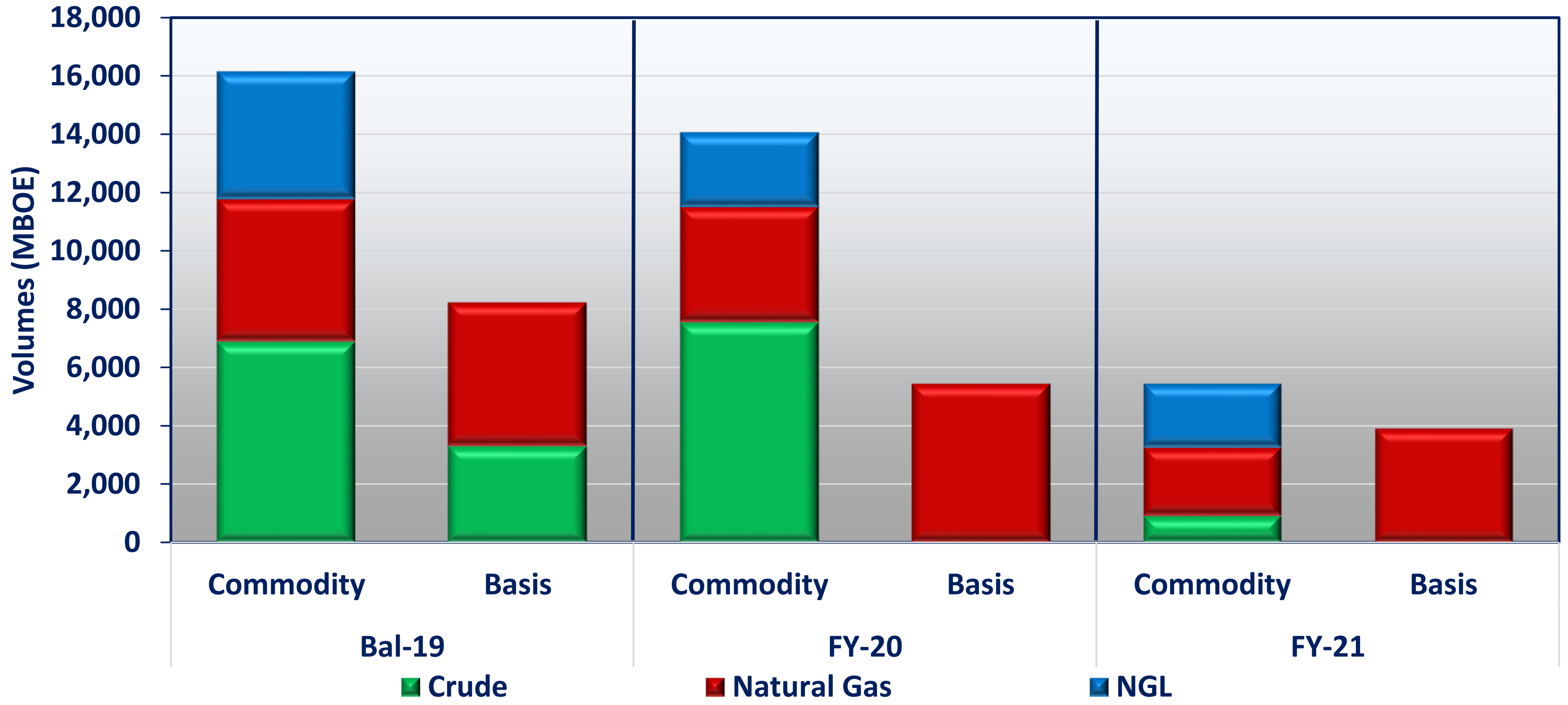
[1]Applicable to ~70% of bal-19E natural gas
Note: Map as of 3/31/19

# Hedging Underpins Continuous Operations




***Will continue to opportunistically layer in product and basis hedges exclusively with our bank group in accordance with our physical transport and expected production***

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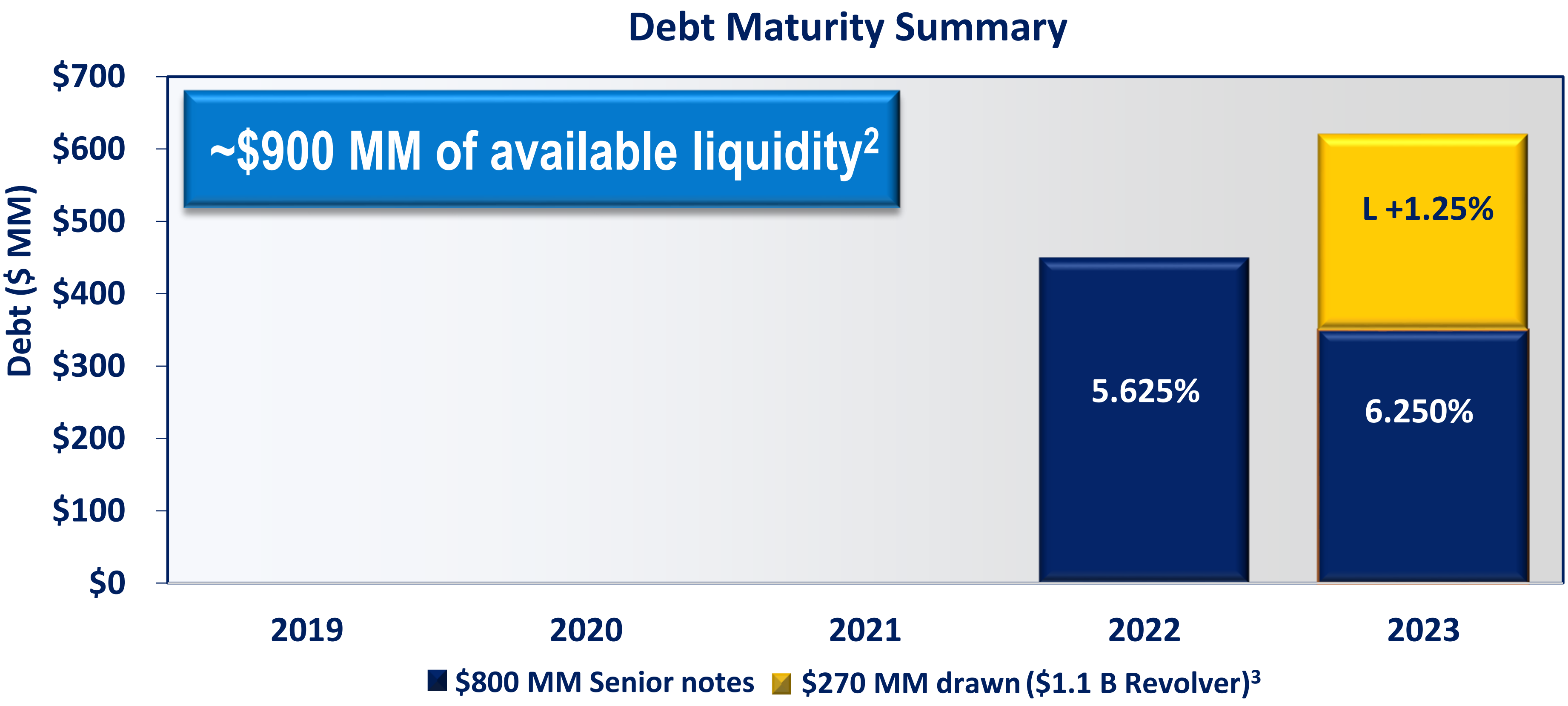
Note: Includes hedges executed through 4/30/19

# Maintaining A Strong Balance Sheet

## ~1.8x net debt to Adjusted EBITDA[1]




[1]Net debt to Adjusted EBITDA is calculated as net debt as of March 31, 2019 divided by trailing twelve-month Adjusted EBITDA ending March 31, 2019 of $568 million. Net debt as of March 31, 2019 was $1,025 million, calculated as the face value of long-term debt of $1,070 million reduced by cash and cash equivalents of $45 million. See Appendix for a reconciliation of Net Income to Adjusted EBITDA.

[2]As of 4/30/19, with $1.1 B aggregate elected commitment in place under Fifth Amended and Restated Senior Secured Credit Facility, decreased by the $270 MM outstanding on the Revolver, increased by cash on hand of ~$86 MM and reduced by ~$14.7 MM outstanding letter of credit

[3]As of 4/30/19, per the semi-annual redetermination of $1.1 B aggregate elected commitment in place under Fifth Amended and Restated Senior Secured Credit Facility

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# Redefined Development Strategy Translates to Increased Value

## Development Strategy

**wider-spacing development + measured growth**

- Reduce future oil decline rates
- Cash flow neutrality
- Increase ROR through wider-spaced development
- Improve long-term capital efficiency

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# APPENDIX

# 2Q-19 Guidance

| | 2Q-19E |
|---|---|
| Total production (MBOE/d)…… | 78.5 |
| Oil production (MBbl/d)…… | 28.5 |
| | |
| Average sales price realizations (without derivatives): | |
| Oil (% of WTI)…… | 95% |
| NGL (% of WTI)…… | 20% |
| Natural gas (% of Henry Hub)…… | 0% |
| | |
| Operating costs & expenses: | |
| Lease operating expenses ($/BOE)…… | $3.30 |
| Production and ad valorem taxes (% of oil, NGL and natural gas revenues)…… | 6.75% |
| Transportation and marketing expenses ($/BOE)…… | $0.75 |
| Midstream service expenses ($/BOE)…… | $0.15 |
| General and administrative expenses: | |
| Cash ($/BOE)…… | $2.00 |
| Non-cash stock-based compensation, net ($/BOE)…… | $0.65 |
| Depletion, depreciation and amortization ($/BOE)…… | $9.30 |

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# Transitional Year With a Focus on Cash Flow Neutrality

| | Expected Activity | 1Q-19A | 2Q-19E | 3Q-19E | 4Q-19E |
|---|---|---|---|---|---|
| *Updated Plan* | Drilling Rigs | 3 | 2 | 2 | 2 |
| | Spuds | 14 | 12 | 12 | 10 |
| | Completion Crews | 2.0 | 1.2 | 1.0 | 1.0 |
| | Completions | 20 | 12 | 9 | 11 |
| *Original Budget* | Drilling Rigs | 3 | 2 | 1 | 1 |
| | Spuds | 16 | 11 | 17 | 6 |
| | Completion Crews | 2.0 | 1.4 | 0.3 | 0 |
| | Completions | 15 | 17 | 4 | 0 |

***Cash-flow protected updated plan enables full-year completions activity***

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Note: All future quarters are approximations

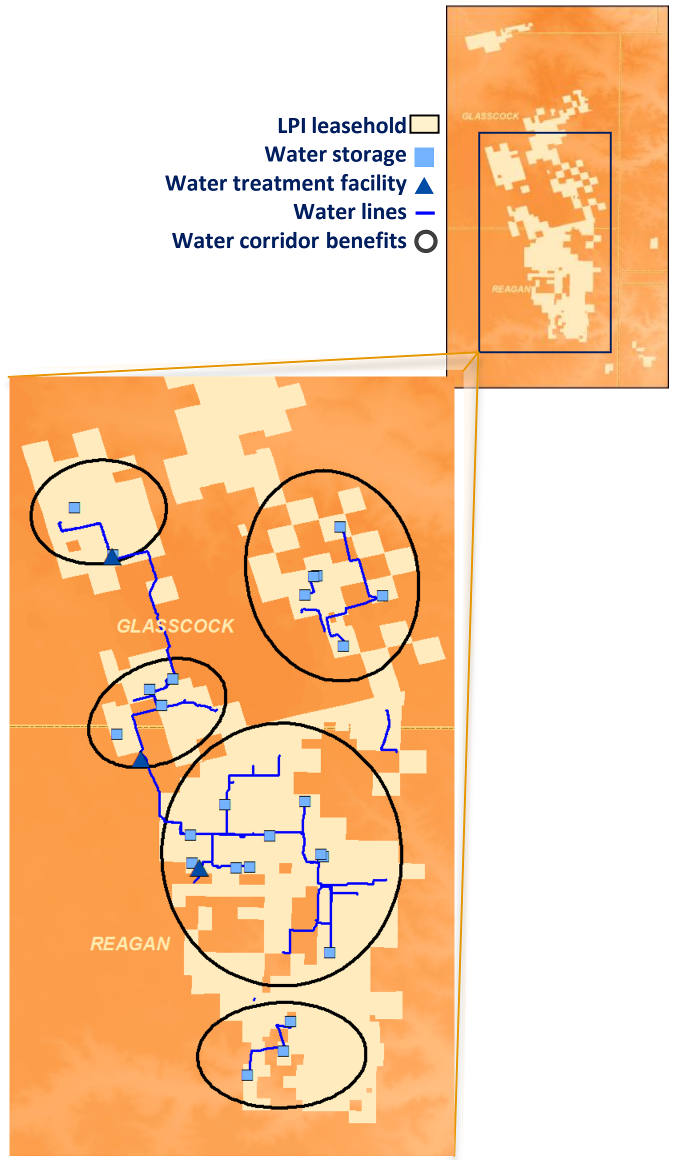
# Significant Benefits Through Water Infrastructure Investments

## Water Infrastructure

- ~115 miles of water gathering & distribution pipelines
- ~75% of produced water gathered by pipe and ~16% of produced water recycled in 1Q-19
- 54 MBWPD produced water recycling capacity
- 22.5 MMBW owned or contracted storage capacity

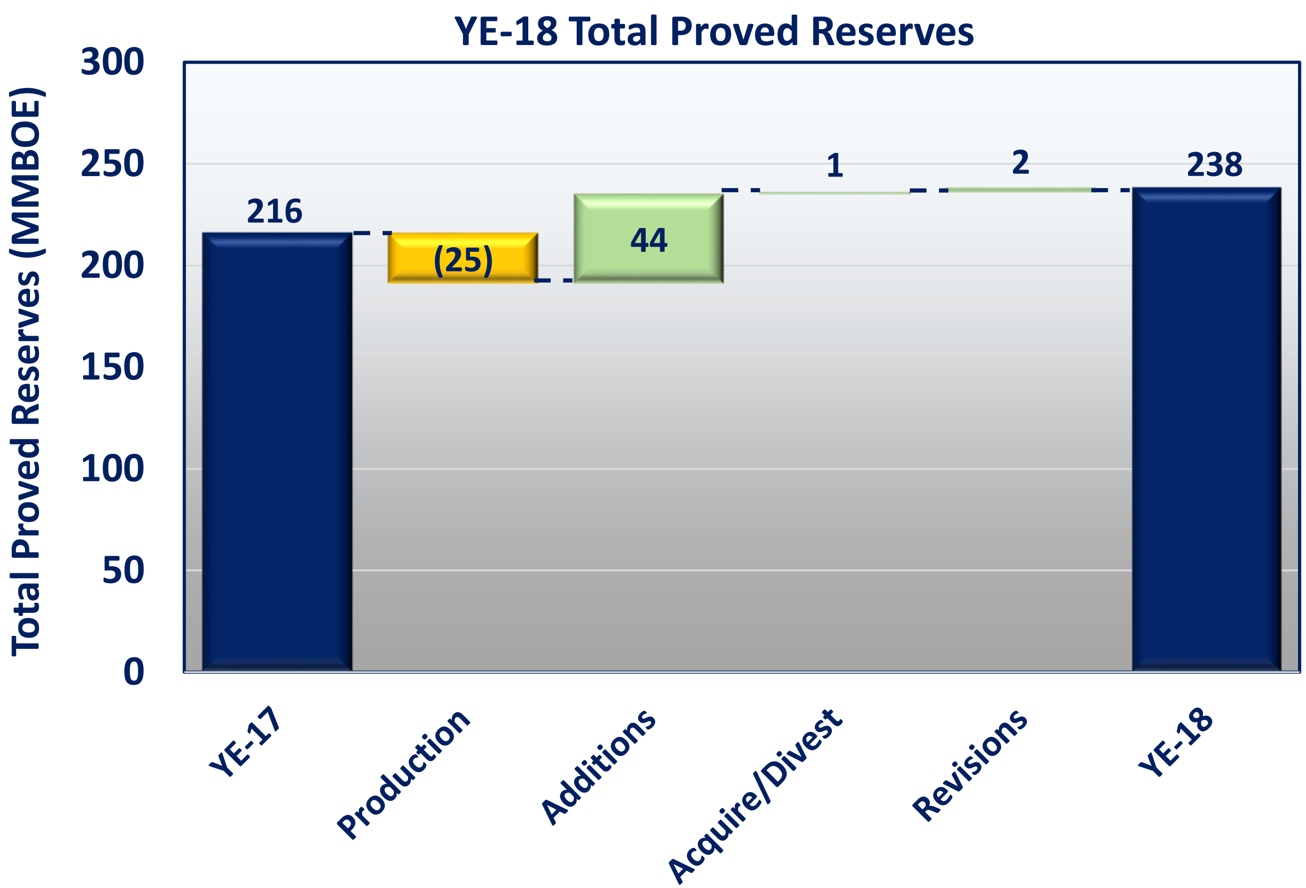
**~$6.8 MM**

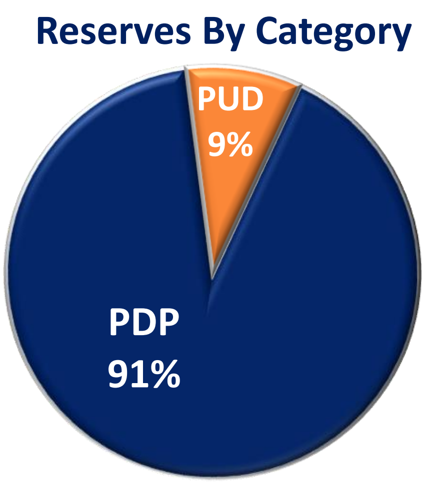
**1Q-19 net savings generated by LMS water infrastructure investments[1]**

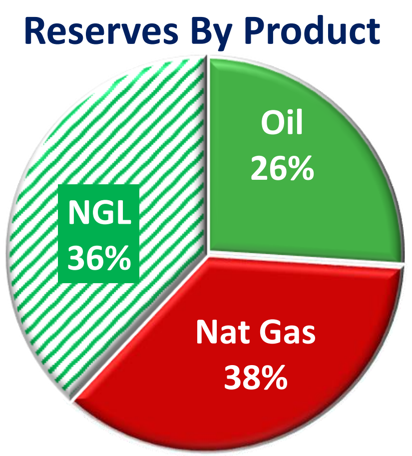



[1]Calculated utilizing a 95% WI & 72% NRI
Note: Statistics, estimates and maps as of 3/31/19

# Organically Grew Total Proved Reserves in 2018



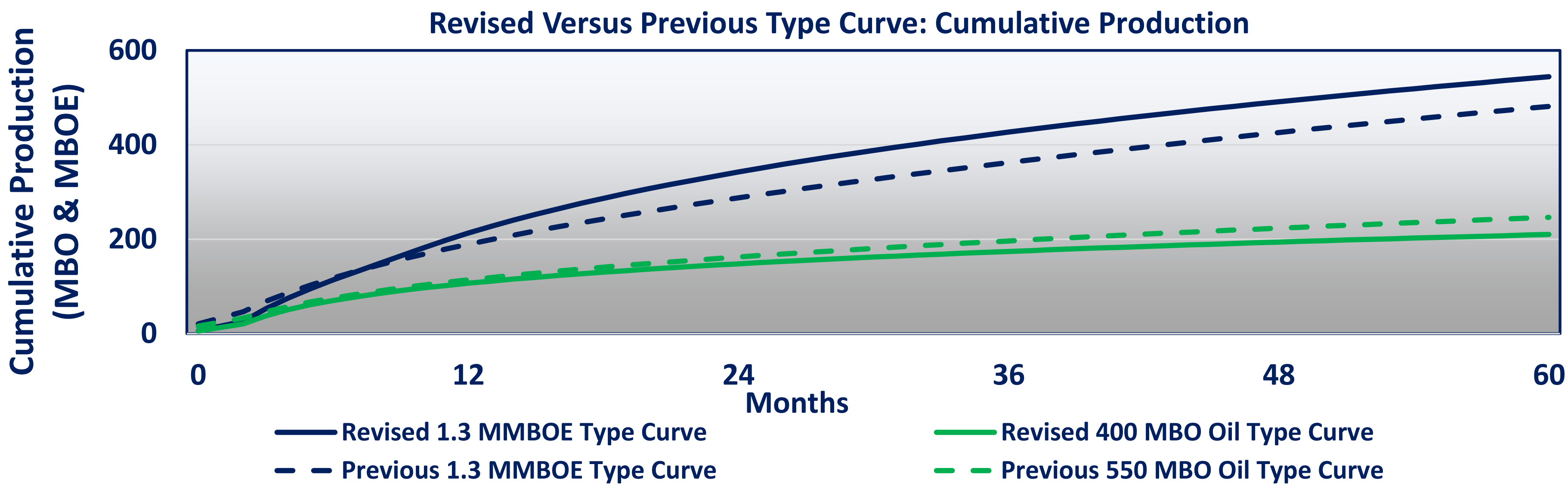




**~19%** YoY increase in total proved reserves value

Note: Based on estimated YE-18 3-stream proved reserves, prepared by Ryder Scott. Reserves have been rounded to the nearest 1 MMBOE

# Revised Type Curve Expected to Yield Similar Returns as Previous




| Revised Type Curve: Production By Year | | | |
|---|---|---|---|
| Year | Oil (MBO) | Total (MBOE) | Oil Cut (%) |
| 1 | 107 | 213 | 50% |
| 2 | 41 | 130 | 32% |
| 3 | 26 | 84 | 31% |
| 4 | 20 | 64 | 31% |
| 5 | 16 | 53 | 30% |
| 5-Year Cumulative | 210 | 544 | 39% |

| Previous Type Curve: Production By Year | | | |
|---|---|---|---|
| Year | Oil (MBO) | Total (MBOE) | Oil Cut (%) |
| 1 | 114 | 189 | 60% |
| 2 | 49 | 98 | 49% |
| 3 | 34 | 75 | 46% |
| 4 | 27 | 64 | 43% |
| 5 | 23 | 55 | 41% |
| 5-Year Cumulative | 246 | 481 | 51% |

***Similar returns driven by accelerated natural gas & NGL recoveries***

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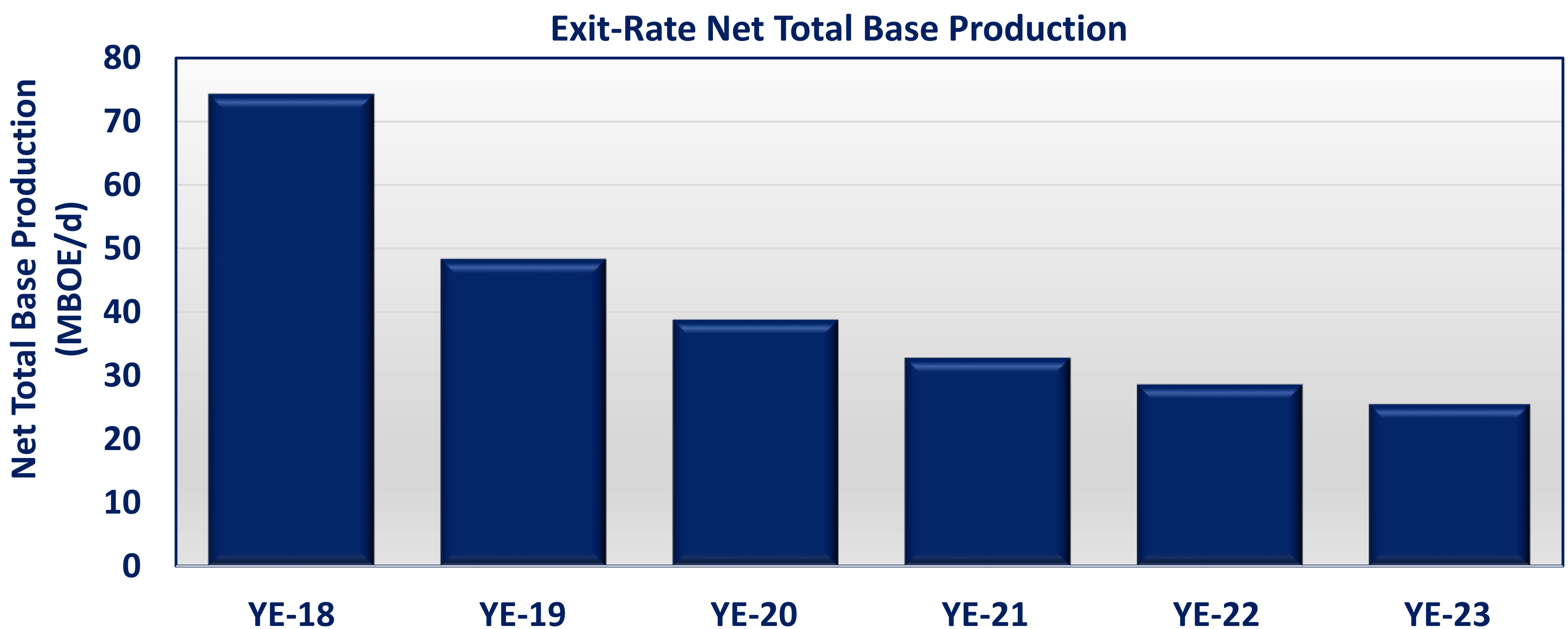
Note: Previous 1.3 MMBOE type curve included a 1.45 b-factor
Revised 1.3 MMBOE type curve includes a 1.20 b-factor
Table may not foot due to rounding

# YE-18 Total PDP Reserves 5-Year Decline

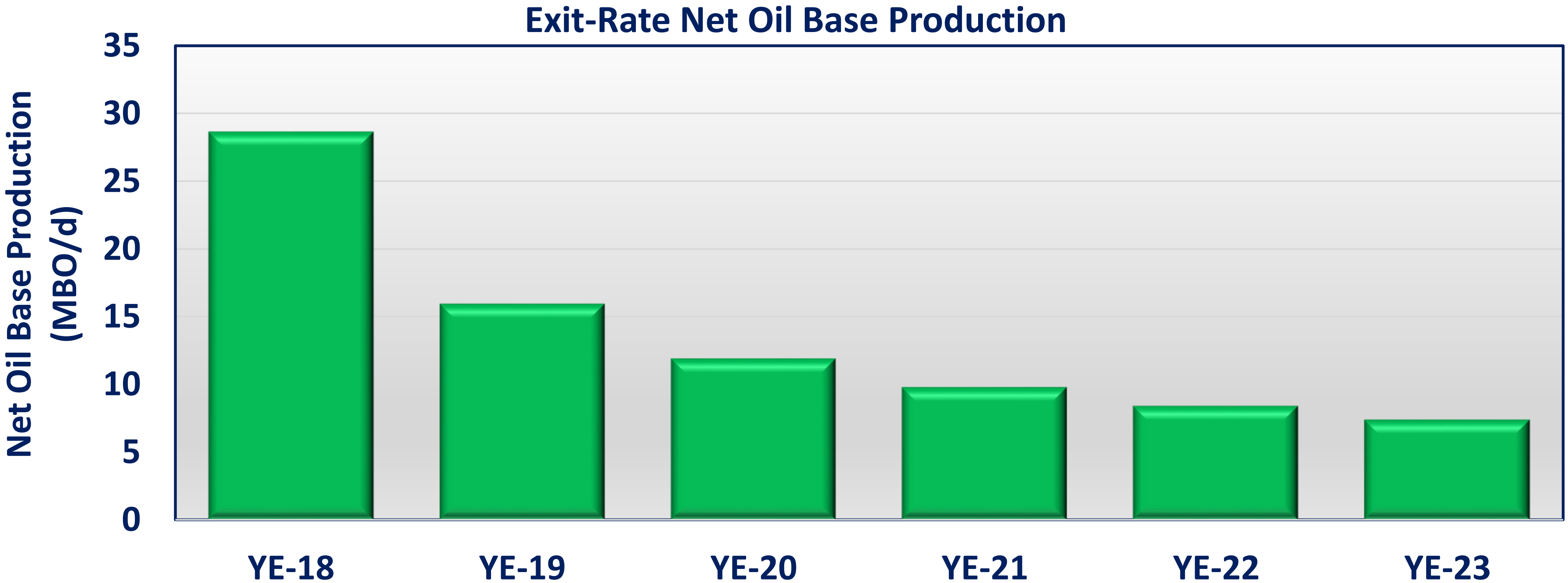



| | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 |
|---|---|---|---|---|---|
| Decline Rate | -35% | -20% | -15% | -13% | -11% |

***Natural gas and NGLs are exhibiting flatter declines, yielding shallower total decline rates than oil***

Note: Based on estimated YE-18 3-stream proved reserves, prepared by Ryder Scott

# YE-18 Oil PDP Reserves 5-Year Decline




| | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 |
|---|---|---|---|---|---|
| Decline Rate | -44% | -25% | -18% | -14% | -12% |

***Future oil decline rates expected to moderate with wider-spacing development strategy***

Note: Based on estimated YE-18 3-stream proved reserves, prepared by Ryder Scott

# Oil, Natural Gas & Natural Gas Liquids Hedges

| Hedge Product Summary | 2Q-19 - 4Q-19 | FY-20 | FY-21 |
|---|---|---|---|
| Oil total floor volume (Bbl) | 6,875,000 | 7,539,600 | 912,500 |
| Oil wtd-avg floor price ($/Bbl) | $60.42 | $58.79 | $45.00 |
| *Oil total floor volume w. deferred premium (Bbl)* | *962,500* | | |
| *Oil wtd-avg deferred premium price ($/Bbl)* | *$4.39* | | |
| Nat gas total floor volume (MMBtu) | 29,425,000 | 23,790,000 | 14,052,500 |
| Nat gas wtd-avg floor price ($/MMBtu) | $3.09 | $2.72 | $2.63 |
| NGL total floor volume (Bbl) | 4,372,500 | 2,562,000 | 2,202,775 |

| Oil | 2Q-19 - 4Q-19 | FY-20 | FY-21 |
|---|---|---|---|
| Puts | | | |
| Hedged volume (Bbl) | 962,500 | 366,000 | |
| Wtd-avg floor price ($/Bbl) | $55.00 | $45.00 | |
| *Hedged Volume w. Deferred Premium (Bbl)* | *962,500* | | |
| *Wtd-avg deferred premium price ($/Bbl)* | *$4.39* | | |
| Swaps | | | |
| Hedged volume (Bbl) | 5,912,500 | 7,173,600 | |
| Wtd-avg price ($/Bbl) | $61.31 | $59.50 | |
| Collars | | | |
| Hedged volume (Bbl) | | | 912,500 |
| Wtd-avg floor price ($/Bbl) | | | $45.00 |
| Wtd-avg ceiling price ($/Bbl) | | | $71.00 |

| Natural Gas - HH | 2Q-19 - 4Q-19 | FY-20 | FY-21 |
|---|---|---|---|
| Swaps | | | |
| Hedged volume (MMBtu) | 29,425,000 | 23,790,000 | 14,052,500 |
| Wtd-avg price ($/MMBtu) | $3.09 | $2.72 | $2.63 |

| Natural Gas Liquids | 2Q-19 - 4Q-19 | FY-20 | FY-21 |
|---|---|---|---|
| Swaps - Ethane | | | |
| Hedged volume (Bbl) | 1,787,500 | 366,000 | 912,500 |
| Wtd-avg price ($/Bbl) | $14.22 | $13.60 | $12.01 |
| Swaps - Propane | | | |
| Hedged volume (Bbl) | 1,430,000 | 1,244,400 | 730,000 |
| Wtd-avg price ($/Bbl) | $27.97 | $26.58 | $25.52 |
| Swaps – Normal Butane | | | |
| Hedged volume (Bbl) | 550,000 | 439,200 | 255,500 |
| Wtd-avg price ($/Bbl) | $30.73 | $28.69 | $27.72 |
| Swaps - Isobutane | | | |
| Hedged volume (Bbl) | 137,500 | 109,800 | 67,525 |
| Wtd-avg price ($/Bbl) | $31.08 | $29.99 | $28.79 |
| Swaps - Natural Gasoline | | | |
| Hedged volume (Bbl) | 467,500 | 402,600 | 237,250 |
| Wtd-avg price ($/Bbl) | $45.80 | $45.15 | $44.31 |

| Basis Swaps | 2Q-19 - 4Q-19 | FY-20 | FY-21 |
|---|---|---|---|
| Mid/Cush | | | |
| Hedged volume (Bbl) | 2,392,000 | | |
| Wtd-avg price ($/Bbl) | -$3.23 | | |
| Hou/Mid | | | |
| Hedged volume (Bbl) | 910,000 | | |
| Wtd-avg price ($/Bbl) | $7.30 | | |
| Waha/HH | | | |
| Hedged volume (MMBtu) | 29,425,000 | 32,574,000 | 23,360,000 |
| Wtd-avg price ($/MMBtu) | -$1.51 | -$0.76 | -$0.47 |

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Note: Open positions as of 03/31/19, hedges executed through 04/30/19
See appendix slide 'Hedge Settlement Details' for settlement details
Hedged volumes with deferred premiums outlined above are included in provided totals and are therefore not additive

# Hedge Settlement Details

Other than the oil basis swaps, the Company's oil derivatives are settled based on the month's arithmetic average of the daily settlement prices for the 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 the differential between the basis swaps' fixed differential price as compared to the differential between the arithmetic average of each day's index prices for the first nearby month on the pricing dates in each calculation period with the index prices being either (i) the Argus Americas Crude's West Texas Intermediate ("WTI") Midland-weighted average and the Cushing-based NYMEX West Texas Intermediate Light Sweet Crude Oil Futures Contract, (ii) the Argus Americas Crude's WTI Midland-weighted average and the WTI formula basis or (iii) the Argus Americas Crude's WTI Houston-weighted average and the WTI Midland-weighted average.

The Company's NGL derivatives are settled based on the month's arithmetic average of the daily average of the high and low OPIS index prices for Mont Belvieu Purity Ethane, TET and Non-TET Propane, Non-TET Normal 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 or the NYMEX index price for Henry Hub for the calculation period. The natural gas basis swaps are settled based on the differential between the basis swaps' fixed differential price as compared to the differential between the Inside FERC index price for West Texas WAHA and the NYMEX index price for Henry Hub for the calculation period.

# 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.

| *(in thousands, unaudited)* | 2Q-18 | 3Q-18 | 4Q-18 | 1Q-19 |
|---|---|---|---|---|
| Net income (loss) | $33,452 | $55,050 | $149,573 | $(9,491) |
| Plus: | | | | |
| Income tax expense (benefit) | - | 1,387 | 2,862 | (96) |
| Depletion, depreciation and amortization | 50,762 | 55,963 | 60,399 | 63,098 |
| Non-cash stock-based compensation, net | 10,676 | 8,733 | 7,648 | 7,406 |
| Accretion expense | 1,121 | 1,114 | 1,131 | 1,052 |
| Mark-to-market on derivatives: | | | | |
| (Gain) loss on derivatives, net | 45,976 | 32,245 | (112,195) | 48,365 |
| Settlements received (paid) for matured derivatives, net | 181 | (3,888) | 12,033 | 102 |
| Premiums paid for derivatives | (5,451) | (5,455) | (5,405) | (4,016) |
| Interest expense | 14,424 | 14,845 | 15,117 | 15,547 |
| Loss on disposal of assets, net | 1,358 | 616 | 1,207 | 939 |
| Adjusted EBITDA | $152,499 | $160,610 | $132,370 | $122,906 |

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